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**BEFORE THE TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE**

IN RE: PETITION OF KINGSPORT POWER COMPANY d/b/a AEP APPALACHIAN POWER FOR APPROVAL OF A STORM DAMAGE RIDER TARIFF	))))	**Docket No. 15-00024**

CONSUMER ADVOCATE'S RESPONSE TO KINGSPORT POWER COMPANY'S REQUESTS FOR PRODUCTION OF DOCUMENTS

The Consumer Advocate and Protection Division of the Office of the Attorney General, pursuant to the Authority's Order Amending Procedural Schedule entered on July 28, 2015, hereby submits its responses to Kingsport Power Company's *Requests for Production of Documents*, including corresponding attachments.

1. **Produce all class cost of service, cost allocation and rate design studies in all electric utility cases, prepared by or participated in by Mr. Novak, during his tenure with WHN Consulting (September, 2004 to present).**

RESPONSE:
The CAPD objects to the question on the grounds that it is overbroad and unduly burdensome. Nearly every project that Mr. Novak has ever undertaken during his tenure with WHN Consulting has involved some type of cost allocation or rate design. Therefore, we interpret this question to request only those projects involving a class cost of service study for electric utilities.

As stated on Page 1 of Attachment 1 to his direct testimony, Mr. Novak has been involved with the following cases involving class cost of service studies for electric utilities during his tenure with WHN Consulting.

Client	Utility	Docket
Bristol TN Essential Services	Bristol TN Essential Services	05-00251

The data supporting the analysis for the class cost of service study mentioned above is subject to individual confidentiality agreements between WHN Consulting and the utility listed above. Therefore, Mr. Novak is unable to release the details of the individual class cost of service study.

2. **Produce all testimony (in any forum) of Mr. Novak related to any class cost of service, cost allocation, and rate design issues sponsored or offered in all electric utility cases, during his tenure with WHN Consulting (September, 2004 to present).**

RESPONSE:
As stated on Page 1 of Attachment 1 to his direct testimony, Mr. Novak has been involved with the following cases involving class cost of service studies for electric utilities during his tenure with WHN Consulting.

Client	Utility	Testimony
Bristol TN Essential Services	Bristol TN Essential Services	Attachment-WHN3

The testimony referred to above is included as a separate attachment to this response.

3. **To the extent not provided in your responses to Request 1, produce all class cost of service, cost allocation, and rate design studies prepared by or participated in by Mr. Novak, as discussed in his curriculum vitae in Attachment 1, Page 1, during his tenure with WHN Consulting (September, 2004 to present). This request is specifically directed to gas and water proceedings.**

RESPONSE:
The CAPD objects to the question on the grounds that it is overbroad and unduly burdensome. Nearly every project that Mr. Novak has ever undertaken during his tenure with WHN Consulting has involved some type of cost allocation or rate design. Therefore, we interpret this question to request only those projects involving a class cost of service study for gas and water utilities.

As stated on Page 1 of Attachment 1 to his direct testimony, Mr. Novak has been involved with the following cases involving class cost of service studies for gas and water utilities during his tenure with WHN Consulting.

Client	Utility	Docket
Ohio Consumers' Counsel	Ohio-American Water Company	09-391-WS-AIR
Tennessee CAPD	Tennessee-American Water Company	10-00189
Tennessee CAPD	Tennessee-American Water Company	12-00049
Tennessee CAPD	Piedmont Natural Gas Company	11-00144
Ohio Consumers' Counsel	Vectren Energy Delivery of Ohio	07-1080-GA-AIR
Tennessee CAPD	Lynwood Utility	11-00198
Texas Attorney General	CenterPoint Energy	GUD 9902
PSS Legal Fund	Aqua North Carolina	W-218, Sub 319

The data supporting the analysis for each and every one of the class cost of service studies mentioned above is subject to individual confidentiality agreements between the client and the utility listed above. Therefore, Mr. Novak is unable to release the details of the individual class cost of service study.

4. **To the extent not provided in your responses to Request 2, produce all testimony (in any forum) of Mr. Novak related to any class cost of service, cost allocation, and rate design issues sponsored or offered by Mr. Novak as discussed in his curriculum vitae, Attachment 1, Page 1, during his tenure with WHN Consulting (September, 2004 to present). This request is specifically directed to gas and water proceedings.**

RESPONSE:
As stated on Page 1 of Attachment 1 to his direct testimony, Mr. Novak has been involved with the following cases involving class cost of service studies for gas and water utilities during his tenure with WHN Consulting.

Client	Utility	Testimony
Ohio Consumers' Counsel	Ohio-American Water Company	Attachment-WHN1
Tennessee CAPD	Tennessee-American Water Company	Attachment-WHN2
Tennessee CAPD	Tennessee-American Water Company	Attachment-WHN4
Tennessee CAPD	Piedmont Natural Gas Company	Attachment-WHN5
Ohio Consumers' Counsel	Vectren Energy Delivery of Ohio	Attachment-WHN6
Tennessee CAPD	Lynwood Utility	Attachment-WHN7
Texas Attorney General	CenterPoint Energy	Attachment-WHN8
PSS Legal Fund	Aqua North Carolina	Attachment-WHN9

The testimony referred to above is included as a separate attachment to this response.

5. **Produce all class cost of service, cost allocation, and rate design studies prepared by or participated in by Mr. Novak during his employment with the Tennessee Regulatory Authority.**

RESPONSE:
The CAPD objects to the question on the grounds that it is overbroad and unduly burdensome. Nearly every project that Mr. Novak had ever undertaken during his employment with the Tennessee Regulatory Authority involved some type of cost allocation or rate design. Therefore, we interpret this question to request only those projects involving a class cost of service study.

To the best of Mr. Novak's knowledge and belief, the Tennessee Regulatory Authority has never adopted a class cost of service study for any utility. Furthermore, to the extent that any class cost of service study was ever presented for consideration by the TRA during Mr. Novak's employment, those records have not been retained by Mr. Novak.

6. **Produce all testimony (in any forum) of Mr. Novak related to any class cost of service, cost allocation, and rate design issues sponsored or offered by Mr. Novak during his employment with the Tennessee Regulatory Authority.**

RESPONSE:

The CAPD objects to the question as overbroad and unduly burdensome. Nearly every project that Mr. Novak had ever undertaken during his employment with the Tennessee Regulatory Authority involved some type of cost allocation or rate design. Therefore, we interpret this question to request only those projects involving a class cost of service study.

To the best of Mr. Novak's knowledge and belief, the Tennessee Regulatory Authority has never adopted a class cost of service study for any utility. Furthermore, to the extent that any testimony regarding a class cost of service study was ever presented to the TRA for consideration by Mr. Novak during his employment with the Tennessee Regulatory Authority, that testimony has not been retained by Mr. Novak.

7. **Relative to documents produced in response to Requests 1-6, produce all work papers/calculations that support the ultimate numbers contained in said studies and testimony.**

RESPONSE:

The data supporting the analysis for each and every one of the class cost of service studies mentioned in response to Items 1 through 6 is subject to individual confidentiality agreements between the client and the utility. Therefore, Mr. Novak is unable to release the work papers/calculations that support the ultimate numbers contained in the individual class cost of service studies.

RESPECTFULLY SUBMITTED,

Erin Merrick

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<u>CERTIFICATE OF SERVICE</u>

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

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Senior Counsel
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Columbus, OH 43215

This the 6th day of August, 2015.

Erin Merrick

Erin Merrick

ATTACHMENT

1

EXHIBIT ________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio	)	
American Water Company To Increase Its	)	
Rates for in Its Entire Service Area for	)	Case No. 09-391-WS-AIR
Water Service and Sewer Service.	)	

DIRECT TESTIMONY
of
WILLIAM H. NOVAK

ON BEHALF OF
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
10 West Broad Street, Suite 1800
Columbus, Ohio 43215

January 4, 2010

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ATTACHMENTS

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am a Certified Management Accountant, and am also licensed to practice as a Certified Public Accountant.

My work experience has centered on regulated utilities for over 25 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee. I also served for two years as the Vice President of Regulatory

Compliance for Sequent Energy Management, a natural gas trading and optimization entity in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

Q3. ***ON WHOSE BEHALF ARE YOU TESTIFYING?***

A3. I am testifying on behalf of the Office of the Ohio Consumers' Counsel ("OCC").

Q4. ***WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?***

A4. My testimony will support certain OCC Objections to the Staff Report and address issues raised by those objections and address concerns with the Ohio American Water Company's ("OAW's" or "the Company's") Application. Specifically I will address the following:

i. OCC's Cost of Service Studies for water and wastewater service;
ii. OCC's allocation of the revenue requirement for water and wastewater service to the different customer classes;
iii. OCC's position on OAW's proposals for annual incremental step rates;
iv. OCC's proposal for uniform rates for Water-C customers;
v. OCC's rate design proposal; and
vi. OCC's position on the Company's proposals for adoption of pass-through provisions.

Q5. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A5. I have reviewed the Company's Rate Case Application as filed on June 8, 2009, along with the testimony and exhibits presented with their filing. In addition, I have reviewed the Company's workpapers related to the cost of service and rate design calculations supporting their filings. I have also reviewed the Company's responses to the relevant data requests submitted by the Staff as well the Company's responses to OCC's discovery requests in these same areas. I have also reviewed the Staff Report along with workpapers provided to the OCC in support of Staff's conclusions. In addition, I reviewed the testimony and exhibits of all parties relating to cost of service and rate design in the Company's last rate case.[1] Finally, I interviewed the Company's cost of service and rate design witnesses at the Company's regional headquarters in St. Louis, Missouri and inspected their supporting documents related to cost of service and rate design.[2]

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[1] PUCO Case No. 07-1112-WS-AIR.

[2] Witnesses Grubb, Verdouw and Herbert. Interview took place on October 20, 2009.

I. WATER & WASTEWATER COST OF SERVICE STUDIES

Q6. PLEASE BRIEFLY EXPLAIN THE COMPANY'S COST ALLOCATION PROCESS IN ITS COST OF SERVICE STUDIES FOR THE WATER AND WASTEWATER DIVISIONS.

A6. The purpose of any Cost of Service Study ("COSS") is to arrive at the cost of serving each customer class and present a systematic approach to allocating this cost (or total revenue requirement) to the different classes of customers. The COSS then provides a measure of guidance for the Commission to consider how to best adjust individual rates for each customer class to produce the revenue requirement.

In this case, the Company has developed a COSS for its water operations using twenty-one (21) separate allocation factors to segregate its proposed revenue requirement of $40,343,374 to each customer class. For wastewater service, the Company has developed a separate COSS using ten (10) allocation factors to segregate its proposed revenue requirement of $4,631,093 to each customer class. A summary of the costs allocated by the Company using each of their proposed allocation factors appears in Attachment WHN-2 with the final results presented below.

Company Proposed Cost of Service		
Customer Class	**Water**	**Wastewater**
Residential	$26,595,399	$4,238,574
Commercial	5,568,674	392,515
Industrial	2,768,311	
Special Contracts	955,067	
Public Authorities	2,123,065	
Sales for Resale	1,577,491	
Private Fire	755,367	
Total	**$40,343,374**	**$4,631,089**

Source: Attachment WHN-2

Q7. DO YOU AGREE WITH THE COMPANY'S METHODOLOGY FOR ALLOCATING ITS REVENUE REQUIREMENTS IN THIS CASE?

A7. No. Six of the twenty-one allocation factors used in the Company's water COSS are based on judgment without any substantiation whatsoever.[3] Likewise, and as discussed further below and in Attachment WHN-3, three of the ten wastewater allocators are also based on the Company's judgment.[4] In addition, I disagree with the Company's use of Allocation Factor 1A in the water COSS to avoid allocating costs that vary with the amount of water consumed by other water utilities under special contracts with the Company. I also disagree with the Company's use of Factor 20 in the water COSS to allocate customer related management fees. I have prepared a detailed critique for each allocation factor used by the Company that I disagree with, and included it in Attachment WHN-3 to my testimony. I do not

[3] Water COSS Allocation Factors 2, 3, 4, 5, 6 and 7.

disagree with the Company's use of the remaining Factors that are not specifically mentioned in my testimony.[5]

Q8. HOW DO YOU KNOW THAT SPECIFIC ALLOCATION FACTORS USED IN THE COMPANY'S WATER AND WASTEWATER COSS ARE BASED ON JUDGMENT?

A8. Attachment WHN-4 includes discovery requests issued by the OCC asking the Company to provide supporting documentation for allocation factors 2, 3, 4, 5, 6 and 7 in the water COSS and allocation factors 1, 2 and 3 in the wastewater COSS.[6] The Company's response to each of these discovery requests indicates that the allocation factors in question were calculated based solely on the judgment of the Company and that no supporting information was available.

Q9. WHY IS IT INCORRECT FOR THE COMPANY TO USE ITS OWN JUDGMENT FACTORS IN ITS PROPOSED WATER AND WASTEWATER COSS?

A9. In this case, millions of dollars in costs are being allocated to the different customer classes based on the Company's best "hunch." In my opinion, it is

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[4] Wastewater COSS Allocation Factors 1, 2 and 3.

[5] For this case, OCC does not disagree with the Company's calculation of allocation factors 8 – 19 in the Water COSS and factors 4 – 10 in the Wastewater COSS.

[6] Specifically, they are Ohio-American Water Company responses to OCC Interrogatories 087, 089, 091, 093, 094, 100, 072, 073, and 074.

unacceptable to use "judgment factors" for a COSS because the result is a COSS that cannot be either verified or independently corroborated. This is clearly not the intent behind the requirement for a properly calculated COSS to be submitted for review that is to be relied upon by the Commission.

Q10. WHY DO YOU DISAGREE WITH THE CALCULATION OF FACTOR 1A IN THE COMPANY'S WATER COSS?

A10. The purpose of Factor 1A is to allocate costs which vary with the amount of water consumed. Factor 1A is based on the average daily consumption for each customer class *with the exception* of special contracts with other water utilities. Since the stated purpose of Factor 1A is to allocate those costs that vary with the amount of water consumed, it seems inappropriate and unjust to exclude special contracts from other water usage in the calculation.

Q11. WHY DO YOU DISAGREE WITH THE CALCULATION OF FACTOR 20 IN THE COMPANY'S WATER COSS?

A11. Factor 20 is used by the Company to allocate uncollectible expense and customer related management fees. To calculate Factor 20, the Company takes the ratio of the number of customers in each customer class to total customers and then applies this ratio to the uncollectible expense and customer related management fees. It is unjust and unreasonable to use Factor 20 to allocate the customer related management fees since these costs *are not* caused directly by the customer, but instead allocated to Ohio from the Company's corporate offices. For comparison, the Company allocates each of its management fees with the following allocation factors:

Company Allocation of Management Fees			
Type	**Cost**	**Allocator**	**Residential %**
Management Fees – Customer Related	*$981,206*	*20*	*91.32%*
Management Fees – Employee Related	*$203,765*	*16*	*71.13%*
Management Fees – Water Quality Related	*$75,944*	*1*	*46.41%*
Management Fees – Other	*$2,333,220*	*15*	*72.49%*

Source: Attachment WHN-3

Q12. WHAT RECOMMENDATION ARE YOU MAKING FOR THE COMMISSION TO CONSIDER THAT WILL ELIMINATE THE JUDGMENT ISSUES USED BY THE COMPANY IN THE DEVELOPMENT OF ALLOCATION FACTORS 2, 3, 4, 5, 6 AND 7 IN THE WATER COSS?

A12. For Allocation Factors 2, 3, 4, 5, 6 and 7 contained in the water COSS, I recommend replacing them with Allocation Factor 1, which is the average daily consumption for all customer classes. This substitution requires no arbitrary judgment to be imposed and results in the fairest allocation of costs since it is based on the average percentage of total water consumed for each customer class. These factors are discussed in greater detail in Attachment WHN-3.

Q13. WHAT RECOMMENDATION ARE YOU MAKING FOR THE COMMISSION TO CONSIDER THAT WILL ELIMINATE THE JUDGMENT ISSUES USED BY THE COMPANY IN THE DEVELOPMENT OF ALLOCATION FACTORS 1, 2 AND 3 IN THE WASTEWATER COSS?

A13. For Allocation Factors 1, 2 and 3 contained in the wastewater COSS, I recommend substituting the average daily consumption which is a subset of Factor 1. Again, this substitution requires no arbitrary judgment to be imposed and results in the fairest allocation of costs since it is based on the average percentage of the total service consumed. These factors are discussed in greater detail in Attachment WHN-3.

Q14. WHAT RECOMMENDATION ARE YOU MAKING FOR THE COMMISSION TO CONSIDER THAT WILL PROPERLY CALCULATE FACTOR 1A IN THE WATER COSS?

A14. To properly calculate Factor 1A, I recommend that special contracts with other water utilities be included in the calculation. This adjustment makes Factor 1A equal to Factor 1. This change is discussed in more detail in on Page 2 of Attachment WHN-3.

Q15. WHAT RECOMMENDATION ARE YOU MAKING FOR THE COMMISSION TO CONSIDER THAT WILL PROPERLY CALCULATE FACTOR 20 IN THE WATER COSS?

A15. Instead of allocating customer related management fees with Factor 20, I advocate using Factor 1, since these costs *should* vary with the amount of water consumed.

Q16. HAVE YOU PREPARED AN ALTERNATIVE WATER AND WASTEWATER COSS FOR THE COMMISSION TO CONSIDER THAT ELIMINATES THE ISSUES DESCRIBED ABOVE?

A16. Yes. I've modified the Company's water and wastewater COSS to properly consider my proposals to remedy the defects described above. A summary of the costs allocated using the OCC's modified allocation factors, with the Company's proposed revenue requirements, appears in Attachment WHN-5.

Q17. WHAT IS THE IMPACT OF THE OCC'S ALTERNATIVE WATER AND WASTEWATER COSS FROM THAT PROPOSED BY THE COMPANY?

A17. A comparison of the costs allocated to each customer class, from Attachments WHN-2 and WHN-5, using the Company's proposed revenue requirements, are shown below:

Comparison of Company & OCC Cost of Service Studies Using Company Proposed Revenue Requirements				
Customer Class	**Water**		**Wastewater**	
	Company	**OCC**	**Company**	**OCC**
Residential	$26,595,399	$22,652,307	$4,238,574	$4,140,654
Commercial	5,568,674	5,771,935	392,515	490,435
Industrial	2,768,311	3,448,391		
Special Cont.	955,067	1,621,432		
Public Auth.	2,123,065	2,329,453		
Sales for Resale	1,577,491	3,993,034		
Private Fire	755,367	526,822		
Total	**$40,343,374**	**$40,343,374**	**$4,631,089**	**$4,631,089**

Source: Attachments WHN-2 and WHN-5

II. ALLOCATION OF OCC REVENUE REQUIREMENTS

Q18. HAVE YOU REVIEWED THE OCC'S REVENUE REQUIREMENT CALCULATION?

A18. Yes. The OCC's proposed revenue increase is presented on Exhibit SBH-6 of OCC witness Hines' testimony. The OCC's proposed increase in rates produces a total Revenue Requirement of $33,837,909 for water and $3,824,860 for wastewater.[7]

[7] These revenue requirement amounts are reduced by the OCC's Other Revenues of $1,158,713 for water and $8,327 for wastewater to get the total cost of service by customer class.

Q19. HAVE YOU PREPARED A NEW COSS THAT IMPLEMENTS THE OCC'S WATER AND WASTEWATER REVENUE REQUIREMENT ALONG WITH YOUR ADJUSTMENTS TO THE COMPANY'S COSS AS DESCRIBED EARLIER IN YOUR TESTIMONY?

A19. Yes. This study for water and wastewater service is contained in Attachment WHN-6 to my testimony. A summary of the costs allocated using the OCC's COSS along with the OCC's Revenue Requirement is presented below.

OCC Proposed Cost of Service with OCC Revenue Requirements		
Customer Class	**Water[8]**	**Wastewater[9]**
Residential	$18,244,612	$3,413,222
Commercial	4,656,020	403,311
Industrial (Inc. Spec. Contracts)	4,147,474	0
Public Auth. (Inc. Spec. Contract)	5,170,885	0
Private Fire	460,205	0
Other Revenues	1,158,713	8,327
Total	**$33,837,909**	**$3,824,860**

Source: Attachment WHN-6, Schedule 1, Page 4 and Schedule 2, Page 1.

Q20. HOW DO YOU PROPOSE TO ALLOCATE THE OCC'S REVENUE REQUIREMENTS TO THE DIFFERENT CONSUMER CLASSES?

A20. In order to allocate OCC's Revenue Requirement, I first compared the results from the OCC's COSS with the Company's current revenues, including Special Contract revenues at regular tariff rates. This calculation is detailed in Attachment WHN-7 with the summary results shown below. The table below also

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[8] Attachment WHN-6, Schedule 1.

[9] Attachment WHN-6, Schedule 2.

demonstrates the calculated Revenue-to-Cost Ratio ("R/C") for each customer class.[10]

OCC Cross Subsidy Calculation-Current Revenues				
Customer Class	**OCC Cost of Service (1)**	**Current Revenues (2)**	**Subsidy (2) – (1)**	**Revenue to Cost Ratio (2) ÷ (1)**
Water:				
Residential	$18,244,612	$21,091,140	$2,846,528	1.16
Commercial	4,656,020	4,963,906	307,886	1.07
Industrial	4,147,474	3,221,561	-925,913	0.78
Public Authorities	5,170,885	3,043,409	-2,127,476	0.59
Private Fire	460,205	614,247	154,042	1.33
Other Revenue	1,158,713	1,158,713	0	1.00
Total	**$33,837,909**	**$34,092,976**	**$255,067**	
Wastewater:				
Residential	$3,413,222	$3,362,680	$-50,542	0.99
Commercial	403,311	442,531	39,220	1.10
Other Revenue	8,327	8,327	0	1.00
Total	**$3,824,860**	**$3,813,538**	**$-11,322**	

Source: Attachment WHN-7.

As shown in the table above, the cost of service for residential water customers is only $18,244,612, but Residential water rates produce $21,091,140 in current revenues. The resulting R/C ratio for this class of 1.16 indicates that the Residential customers' rates are meeting the cost of providing their service and subsidizing other customer classes by 16% of their cost.

[10] As explained in Answer 6 above, the purpose of the Cost of Service study is to arrive at the cost of serving each customer class and present a systematic approach to allocating this cost (or total revenue requirement) to each customer class. Once the costs for the customer classes are determined, it would then be compared to the revenues accrued from the same classes to arrive at their Revenue-to-Cost-Ratios ("R/C"). A revenue-to-cost-ratio less than 1.00 indicates that the class **receives** a rate subsidy from other customers while a ratio greater than 1.00 indicates that the class **pays** a rate subsidy to other customers. A revenue-to-cost ratio equal to one indicates that the class pays exactly its cost of service; it neither receives nor pays a subsidy to the other classes.

Likewise, the cost of service for residential wastewater customers is $3,413,222, but residential wastewater rates only produce $3,362,680 in current revenues. The resulting R/C ratio of 0.99 indicates that residential wastewater customers are receiving a small subsidy from commercial wastewater customers.

I recommend that the Commission allocate the Company's revenue requirements in a manner that would eliminate these subsidies between customer classes – with the exception of Public Authority customers as explained below – by setting rates closer the cost of providing utility service to each customer class.

Q21. WHY HAVE YOU INCLUDED REVENUES FROM SPECIAL CONTRACTS AT THE REGULAR TARIFF RATES INSTEAD OF THE CONTRACT RATES IN YOUR SUBSIDY CALCULATION?

A21. My analysis indicated that special contract customers[11] receive a discounted rate from the already subsidized tariff rates for other industrial and public authority tariffs. I do have some concern over the proper treatment of the delta revenues[12] from these special contract customers as well as the proper regulatory approval process for special contracts. The issue here is that for certain contracts that were approved by the PUCO, the Commission said that the special contracts would not

[11] Whirlpool, Poet, US Yachiyo and Consumers' Ohio Water (Ashtabula County).

[12] Delta revenue is a defined term in Ohio Administrative Code ("OAC") 4901:1-38-01(c). Specifically, "delta revenue" means the deviation resulting from the difference in rate levels between the otherwise applicable rate schedule and the result of any reasonable arrangement approved by the commission.

impact residential rates. That being the case, no cost for revenue deficiency should be allocated to any customer class, including the residential class. For those contracts that have expired or were never approved by the Commission, there is no authority for causing residential customers to subsidize the special contract rates. Finally, delta revenues from competitive response contracts typically are borne by the Company as the primary beneficiary. In order to properly calculate the total subsidy for each customer class, it was necessary to combine the special contract customers with the other industrial and public authority customer classes.

Q22. DID THE PUCO STAFF PROPOSE A SIMILAR REVENUE REQUIREMENT ALLOCATION?

A22. No. On page 36 of the Staff Report, the PUCO Staff *appears* to first accept the results of the Company's COSS where they state that "Staff reviewed the Applicant's cost of service study and found it to be reasonable with consideration for Staff's comments below." However, on page 37 of the Staff Report, the PUCO Staff adopts the Company's proposed revenue distribution percentages as a means to allocate their proposed revenue requirements to the different customer classes without a separate COSS calculation.

The Staff's methodology here is incorrect. The Company's proposed revenue distribution to the different customer classes is based upon its own revenue requirement calculation that is <u>included</u> in the Company's COSS. The PUCO Staff has no COSS of their own nor have they attempted to adapt the Company's COSS to their revenue requirement calculation. Since the PUCO Staff's revenue requirement calculation is *materially different*[13] from the Company's, it is inappropriate for the PUCO Staff to adopt the Company's proposed revenue distribution to allocate their revenue requirements to the different customer classes.

To briefly illustrate, the PUCO Staff's calculation of "income available for return" is materially different than the Company's.[14] However, the Company has allocated only their own calculation of income available for return within their COSS. The PUCO Staff has not calculated a separate COSS to allocate their calculation of income available for return and instead just adopts the Company's resulting revenue distribution. Since the PUCO Staff's income available for return is *materially different* from the Company's, it is inappropriate for the PUCO Staff to adopt the Company's revenue distribution allocation.

[13] Staff Report, Schedule A-1.

[14] See Staff Report, Schedule A-1, Page 81, Line 5 – Required Operating Income.

Q23 WHY ARE YOU PROPOSING TO ALLOCATE THE WATER REVENUE DEFICIENCY TO THE INDUSTRIAL AND SPECIAL CONTRACT CUSTOMERS?

A23. As shown on page 38 of the Staff Report, neither the Company nor the PUCO Staff have proposed to allocate any increase in their revenue requirement to the industrial and special contract customers, even though the cost to serve these customers is *actually greater* than the revenues that they generate.[15]

The rates for special contract customers were initially set based upon their individual competitive alternatives for water service. However, since the time that these competitive rates were set, the Company has indicated that OAW's cost of providing water service has increased substantially.[16] As a result, it is likely that the cost of obtaining alternative water supplies for these customers has also increased. Therefore, it is only just and reasonable that the revenue requirement be allocated to the Special Contract customers since their current revenues do not cover the costs of providing service to them. Moreover, if the purpose of the discount to these industrial customers is a competitive response, then a calculation of the delta revenues should be done and this delta revenue should be recovered

[15] See Company Water COSS, Section E-3.2, Schedule A, Page 1 of 33.

[16] Direct testimony of Company witness Little, Pages 4, 10.

from the Company's shareholders.[17] My allocation is another way of achieving the objective that customers not subsidize the Company's competitive response activities. Indeed, in electric cases, the Commission has generally not required other customers to subsidize a competitive response while requiring them to do so when the special contract is to enable economic development.[18]

Q24. WHAT IF THE IMPACT OF A RATE INCREASE TO SPECIAL CONTRACT CUSTOMERS CAUSES THEM TO CONSIDER LEAVING THE SYSTEM?

A24. The Company can file a new special contract with the PUCO if it decides that competitive conditions warrant such a change. Obviously, in setting the current contract rates, the PUCO did not intend for them to perpetually remain in effect. That is why these contracts all have termination dates. Instead, they were based upon a competitive environment at a single point in time. In this case, as well as in the Company's previous rate case, no evidence has been presented to show that any increase to special contract customers will have a detrimental impact upon their operations. Instead, both the Company and the PUCO Staff have not allocated any of their proposed increase in rates to Special Contract customers,

[17] Given that OAW has already confirmed that these contracts are "competitive" in nature, the resulting delta revenues should not be paid by OAW's other customers. See Company response to PUCO S075 confirming that these contracts are competitive in nature.

[18] For cases addressing the treatment of delta revenue in the context of economic development see 09-0119-EL-AEC and 09-0516-EL-AEC with the PUCO Opinion & Orders issued on July 15, 2009 and October 15, 2009.

with the resulting impact being felt by all other customers, including residential customers.

III. RATE DESIGN

Q25. HOW DO YOU PROPOSE THAT RATES SHOULD BE DESIGNED TO ACHIEVE YOUR RECOMMENDED ALLOCATION OF REVENUE REQUIREMENTS?

A25. First, I propose that the Commission adopt customer class rate schedules for OAW similar to what they have done for gas and electric utilities. Currently, all of the Company's customers purchase their water and wastewater service off a single rate schedule. Under a customer class tariff structure, each customer class (Residential, Commercial, etc.) will have its own set of tariff rates. Customer class rate schedules will allow the Commission to "sculpt" rates to a particular customer class without impacting the rates for the other customer classes.

Next, I propose that the Commission adopt the appropriate rate for monthly service charges. The Company has three separate fixed monthly charges for customer service, water softening and reverse osmosis. The PUCO Staff has presented their proposed charges for these three services in the Staff Report.[19]

Q26. DO YOU AGREE WITH THE MONTHLY SERVICE CHARGES AS RECOMMENDED IN THE STAFF REPORT?

A26. I disagree with the PUCO Staff's recommendation of the monthly customer service charge of $9.51 for 5/8" meters, and instead support the Staff's calculation of $9.13 for this charge. As shown on Page 51 of the Staff Report, the PUCO Staff actually calculates a monthly customer charge of $9.13 for 5/8" meter service. However, it is mentioned on Page 48 of the Staff Report, that the Staff "recommends maintaining the current customer charge of $9.51 for 5/8 inch meters." It is unclear from the Staff Report exactly why the PUCO Staff does not recommend approval of its calculated charge of $9.13 for 5/8" meter service. With this one exception, I am in agreement with the remaining monthly service charges as proposed by the PUCO Staff.

Q27. WHAT IS YOUR POSITION REGARDING MOVING TOWARD UNIFORM RATES?

A27. I support the concept of uniform tariffs and a uniform rate design for OAW. However, it must be achieved while avoiding rate shock. If all of my recommendations with regard to rate design, i.e. shifting costs to eliminate interclass subsidies except for Public Authority customers, are adopted, then uniform rates can be obtained in this case because there would be no rate shock. On the other hand, if the PUCO does not adopt my rate design proposal to

[19] Staff Report, Pages 40-43 and 47-51.

eliminate interclass subsidies, then a more gradual approach towards uniform rates might be necessary to avoid rate shock.

Q28. HOW DO YOU PROPOSE TO DESIGN RATES FOR THE REMAINING REVENUE REQUIREMENT?

A28. For the remaining revenue requirement for <u>water service</u>, I recommend that the existing usage rates for each customer class be adjusted to eliminate all of the customer class subsidies described above, with the exception of Public Authority customers. I also recommend that the rate differentials between the Water-A and Water-C service territories be eliminated in order to create uniform rate schedule for each customer class.

For the remaining revenue requirement for <u>wastewater service</u>, I also recommend that the existing usage rates for each customer class be adjusted to eliminate all of the customer class subsidies.

Q29. WHY ARE YOU PROPOSING TO MAINTAIN THE EXISTING RATE SUBSIDY FOR PUBLIC AUTHORITY CUSTOMERS?

A29. Public Authority customers provide services that benefit all customer classes in OAW's service territory. There is a time lag facing Public Authority customers in securing additional sources of funding (e.g., taxes) that will enable them to pay their full cost of service. However, this measure is only temporary because over time, all customers--including Public Authority customers--should pay their full cost of service.

Q30. HAVE YOU PREPARED A RATE DESIGN CALCULATION BASED ON THE OCC'S REVENUE REQUIREMENT THAT ACHIEVES THE PROPOSALS YOU HAVE OUTLINED?

A30. Yes. Attachment WHN-7 contains the complete calculation for my rate design proposal. A comparison of OCC's proposed rates with the proposed rates from the Company's filing is presented below.

	Company Proposed Rates[20]	**OCC Proposed Rates[21]**
Customer Charges:		
5/8" Meter	$11.39	$9.13
3/4" Meter	14.41	12.05
1.0" Meter	20.43	17.90
1.5" Meter	35.51	32.53
2.0" Meter	53.60	50.09
3.0" Meter	95.81	91.04
4.0" Meter	156.11	149.56
8.0" Meter	306.86	295.84
Flat Rate Charges:		
Residential	$98.37	$71.74
Commercial	98.37	77.83
Service Charges:		
Softening-Water A	$0.3415	$0.3415
Softening-Water C	0.5745	0.5745
Reverse Osmosis	1.4994	1.4994

[20] Company filing, Schedule E-4.1.

[21] Attachment WHN-7.

Private Fire Service Charges:		
2.0" Diameter	$10.30	$6.66
2.5" Diameter	16.16	10.44
3.0" Diameter	23.19	14.99
4.0" Diameter	41.20	26.63
6.0" Diameter	92.78	59.95
8.0" Diameter	164.98	106.61
10.0" Diameter	257.76	166.56
12.0" Diameter	371.15	239.84
Sprinkler Head	1.26	0.82

	Block 1	**Block 2**	**Block 3**
Usage Charges (Per Ccf):			
Water:			
Residential	$4.6855	$3.3701	$1.5133
Commercial	5.0828	3.6559	1.6416
Industrial & S/C	7.2781	5.2348	2.3506
Public Authority & S/C	5.1147	3.6788	1.6519
Wastewater:			
Residential	$8.3839	$5.9215	$2.3114
Commercial	7.5282	5.3171	2.0754

Source: Attachment WHN-7

Q31. HAVE YOU MEASURED THE IMPACT OF THE RATE INCREASE TO EACH CUSTOMER CLASS FROM YOUR PROPOSED RATE DESIGN?

A31. Yes. The impact of my proposed rate design to each customer class is also shown in Attachment WHN-7. A summary of these calculations are presented below.

Impact of OCC Proposed Rate Design		
Customer Class	**Water**	**Wastewater**
Residential	-6.81%	1.50%
Commercial	1.05%	-8.86%
Industrial & Special Contracts	38.70%	
Public Authorities & Special Contracts	0.00%	
Private Fire	-19.29%	
Total	**-0.78%**	**0.30%**

Source: Attachment WHN-7, Schedule 1

Q32. WHAT IS THE SUBSIDY FOR EACH CUSTOMER CLASS AFTER THE IMPLEMENTATION OF YOUR RATE DESIGN?

A32. After the implementation of my rate design, all subsidies between rate classes are eliminated with the exception of Public Authority. The detailed subsidy calculation is presented in Attachment WHN-7 with the summary results presented below.

OCC Cross Subsidy Calculation-Proposed Revenues				
Customer Class	**OCC Cost of Service (1)**	**OCC Rate Design (2)**	**Subsidy (2) – (1)**	**Revenue to Cost Ratio (2) ÷ (1)**
Water:				
Residential	$18,244,612	$19,655,090	$1,410,478	1.08
Commercial	4,656,020	5,016,038	360,018	1.08
Industrial	4,147,474	4,468,150	320,676	1.08
Public Authorities	5,170,885	3,043,445	-2,127,440	0.59
Private Fire	460,205	495,759	35,554	1.08
Other Revenues	1,158,713	1,158,713	0	1.00
Total	**$33,837,909**	**$33,837,195**	**$- 714**	
Wastewater:				
Residential	$3,413,222	$3,413,120	-$102	1.00
Commercial	403,311	403,323	12	1.00
Other Revenues	8,327	8,327	0	1.00
Total	**$3,824,860**	**$3,824,770**	**$- 90**	

Source: Attachment WHN-7, Schedule 1

Q33. HOW MUCH WILL THE AVERAGE RESIDENTIAL WATER AND WASTEWATER BILL CHANGE UNDER YOUR PROPOSED RATE DESIGN?

A33. According to my calculations, the Company's average residential customer uses 10.21 Ccf of water per month in the Company's Water-A service territory and 6.09 Ccf of water per month in the Company's Water-C service territory. Based on my proposed rate design, this means that the average residential monthly bill in the Company's Water-A service territory will decrease by $5.02 or -8.10% (from $61.99 to $56.97), while the monthly bill in the Company's Water-C service territory will decrease by $2.57 or -6.38% (from $40.23 to $37.66). The average residential wastewater bill (Water-C Customers only) will increase by $0.75 or 1.50% (from $50.30 to $51.05).

IV. STEP RATES

Q34. HAVE YOU REVIEWED THE COMPANY'S PROPOSAL TO INCREASE THEIR RATES IN THREE SEPARATE ANNUAL STEPS?

A34. Yes.

Q35. WHAT IS THE COMPANY'S PROPOSAL REGARDING THE THREE-STEP RATE INCREASE?

A35. In addition to the Company's proposed increase of approximately $8.8 million in this immediate case, the Company is also requesting a further three-step increase of $9.5 million effective in April 2011; $3.5 million effective in April 2012; and $3.2 million effective in April 2013.[22] These proposed changes will increase customer rates by a total of $25 million or approximately 68% over presently existing rates.

Q36. WHAT IS THE STAFF'S POSITION REGARDING THE REQUESTED THREE-STEP RATE INCREASE?

A36. The Staff is opposed to the Company's proposed three-step increase. As stated in the Staff Report, the Staff believes that it is not appropriate to establish rates based upon the Company's five-year business plan.[23] In addition, the Staff also points out the impracticalities of investigating and approving each step increase within the 90 day timeframe proposed by the Company.

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[22] PUCO Staff Report, page 2.

[23] PUCO Staff Report, page 22.

Q37. ***WHAT IS YOUR OPINION REGARDING THE REQUESTED THREE-STEP RATE INCREASE?***

A37. It is my position that the Commission should reject the proposal. The Company states in its testimony that costs would be lower through the adoption of step rates since the external costs of filing a new rate case would be eliminated, and this cost reduction would then be passed on to customers. However, while there may not be any question that certain rate case costs would be eliminated, so too would the Company's incentive to minimize their prudently incurred costs of providing service. Since the Company would be guaranteed recovery of all costs through an annual adjustment, there would be no incentive for them to minimize their costs of service. Also, there is no procedure outlined in the Company's proposal for resolving disputes between parties as to exactly what costs were prudently incurred in the interim step rate process. Moreover, to the extent that there could be decreases in certain categories of costs, there would be no opportunity to offset any cost increases by these decreased costs in arriving at an appropriate revenue requirement. Finally, I have been advised by counsel regarding Ohio's ratemaking laws as set forth under Ohio Revised Code section 4909.18, among other statutes. Based in part of the advice that I have received, it is my opinion that the implementation of any step rate increase proposal is inconsistent with ratemaking laws as set forth under Ohio Revised Code section 4909.18, among other statutes.

Q38. CAN THE COMPANY'S FILED COSS BE RELIED UPON FOR THE DETERMINATION OF THE STEP INCREASES?

A38. No, they can not. As discussed earlier, the Company's COSS in this case cannot be relied upon because the Company used judgment factors that cannot be independently verified or corroborated. As a result, any future step increases that rely upon the Company's COSS in this case should also be rejected. This means that any future step increase in rates would need to be accompanied with a corresponding COSS.

Any change in rates should be based upon a properly calculated COSS. Since a properly calculated COSS related to future step rates has not been filed, in my opinion, the PUCO should reject the Company's proposals for step rate increases.

V. UNIFORM TARIFF RATES

Q39. HAVE YOU REVIEWED THE COMPANY'S PROPOSAL TO ADOPT UNIFORM RATE BLOCKS AND RATES FOR ITS WATER-C SERVICE TERRITORY?

A39. Yes. The Company's proposed rate design advocates for a move towards uniform rate blocks and uniform volumetric rates in order to match the tariffs of Water-C customers with those of Water-A.[24]

Q40. DO YOU AGREE WITH THE COMPANY'S PROPOSAL FOR UNIFORM RATE BLOCKS AND RATES?

A40. Not entirely. The Company moves towards uniform rates in a piecemeal approach. I propose to move completely towards uniform rates along with the elimination of rate subsidies as discussed earlier in my testimony.

VI. PASS-THROUGH PROVISIONS

Q41. HAVE YOU REVIEWED THE COMPANY'S AUTOMATIC PASS-THROUGH PROVISIONS?

A41. Yes. The Company has separately proposed a Purchased Water Adjustment, an Infrastructure Recovery Replacement Charge Rider, and an Unavoidable Expense Rider (collectively "pass-through provisions").[25]

Q42. PLEASE DESCRIBE THE INFRASTRUCTURE REPLACEMENT RIDER.

A42. The Infrastructure Replacement Charge Rider would allow the Company to recover the costs for new plant additions as they are placed in service rather than

[24] Direct testimony of Company witness Grubb, Page 17.

[25] Testimony of Company witness Grubb, Page 19.

waiting until the next rate case to realize recovery. However, such a proposal would appear to significantly reduce the Company's risk and therefore its return on equity award. Unfortunately, no such reduction in risk is recognized in the Company's Application. In addition, the Company's proposal for annual step rates (described above in Section III) would seem to make this rider obsolete.

Q43. PLEASE DESCRIBE THE UNAVOIDABLE EXPENSE RIDER.

A43. The Unavoidable Expense Rider would allow the Company to recover increases in select expenses automatically each year without the need for a rate case.[26] However, the rider would also eliminate the Company's incentives to be cost efficient since these costs would be automatically recovered. In addition, the Company's proposal for annual step rates (described above in Section III) would seem to make this rider obsolete.

Q44. PLEASE DESCRIBE THE PURCHASED WATER ADJUSTMENT RIDER.

A44. The Purchased Water Adjustment Clause would allow the Company to automatically pass through its charges for water rate increases that have been approved by regulatory bodies in other states instead of waiting for a rate case to recover these cost changes.

[26] Testimony of Company witness Grubb, Page 20.

Q45. WHAT IS THE STAFF'S RECOMMENDATION ON THESE PASS-THROUGH PROVISIONS?

A45. The Staff recommends that the Commission reject all three pass-through provisions proposed by the Company.[27]

Q46. WHAT IS YOUR RECOMMENDATION ON THESE PASS-THROUGH PROVISIONS?

A46. In its testimony, the Company attempts to provide justification for these pass-through provisions by pointing to similar riders allowed by the Commission for gas and electric utilities.[28] However, these other riders largely relate to wholesale energy costs and other costs (e.g., environmental recovery, capacity costs, reserve margin for switched load) that are completely outside the control of the utility *and* generally volatile in nature. There are no similarly related wholesale costs for a water utility which would warrant pass-through treatment. I therefore recommend that the Commission reject all three pass-through proposals. It appears likely from the Company's testimony that they intend to be filing annual rate cases for at least the next three years, either through step increases or actual rate case filings. Therefore the Company's rationale for these three automatic pass-through provisions is not justified, and only serves to reduce the Company's business risk without a corresponding adjustment to the equity return.

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[27] Staff Report, pages 23 – 26.

[28] Direct testimony of Company witness Grubb, Page 21.

Q47. DOES THIS COMPLETE YOUR TESTIMONY?

A47. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available. I also reserve the right to supplement my testimony in the event that the PUCO Staff fails to support the recommendations made in the Staff Report and /or changes any position in the Staff Report.

CERTIFICATE OF SERVICE

I hereby certify that a copy of *Direct Testimony of William H. Novak on Behalf of the Office of the Ohio Consumers' Counsel* was provided to the persons listed below via first class U.S. Mail, postage prepaid, this 4th day of January, 2010.

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ATTACHMENT

2

EXHIBIT ________

BEFORE
THE TENNESSEE REGULATORY AUTHORITY

In The Matter Of The Petition Of	)	
Tennessee American Water Company To	)	
Change And Increase Certain Rates and	)	
Charges So As To Permit It To Earn A	)	Docket No. 10-00189
Fair And Adequate Rate Of Return On Its	)	
Property Used and Useful In Furnishing	)	
Water Service To Its Customers.	)	

DIRECT TESTIMONY
of
WILLIAM H. NOVAK

ON BEHALF OF
THE CONSUMER ADVOCATE AND PROTECTION DIVISION
OF THE
TENNESSEE ATTORNEY GENERAL'S OFFICE

January 5, 2011

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ATTACHMENTS

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am a Certified Management Accountant, and am also licensed to practice as a Certified Public Accountant.

My work experience has centered on regulated utilities for over 25 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee. I also served for two years as the Vice President of Regulatory

Compliance for Sequent Energy Management, a natural gas trading and optimization entity in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am testifying on behalf of the Consumer Advocate & Protection Division ("CAPD" or "the Consumer Advocate") of the Tennessee Attorney General's Office.

Q4. HAVE YOU PRESENTED TESTIMONY IN ANY PREVIOUS TAWC RATE CASES?

A4. Yes. I presented testimony in Dockets U-86-7402, U-87-7534, 89-15388, 91-05224 and 93-06946 concerning Tennessee-American Water Company ("TAWC" or "the Company") rate cases as well as other generic tariff and rulemaking matters. In addition, I have advised the TRA on issues in other TAWC rate cases in dockets where I did not present testimony.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A5. My testimony will support and address the CAPD's positions and concerns with respect to the Company's Petition. Specifically, I will address the following:

i. CAPD's proposed test period;

ii. CAPD's position on TAWC's proposed Cost of Service Study; and

iii. CAPD's position on TAWC's proposed Weather Normalization Adjustment.

Q6. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A6. I have reviewed the Company's Rate Case Application as filed on September 17, 2010, along with the testimony and exhibits presented with their filing. In addition, I have reviewed the Company's workpapers related to the Cost of Service and Weather Normalization calculations supporting their filings. I have also reviewed the Company's responses to the relevant data requests submitted by the TRA as well the Company's responses to CAPD's discovery requests in these same areas. Finally, I have reviewed the testimony and exhibits of all parties relating to Cost of Service and Weather Normalization in the Company's last rate case.[1]

I. TEST PERIOD

Q7. WHAT TEST PERIOD IS THE CAPD PROPOSING IN THIS CASE?

A7. The CAPD is proposing to use the twelve months ended September 30, 2010 as the appropriate test period, with adjustments for known and reasonably anticipated changes through the attrition year ending December 31, 2011. The CAPD's proposed test period utilizes the most recent information that the Company did not have available at the time they filed their case.

Q8. IS THERE A PRECEDENT FOR UPDATING THE TEST PERIOD WITHIN A RATE CASE?

A8. Yes. The TRA and its predecessor the Tennessee Public Service Commission have often updated the test period within a rate case when it may not be reflective of future operating conditions.[2] This is due to the fact that the operating results within the test period can become "stale" between the date that the rate case is first filed by the Company and the time that a decision is made and an order is developed. Updating the test period to reflect the most recent operating results helps to eliminate any concerns over obsolete data.

Q9. HAVE YOU REVIEWED THE COMPANY'S TESTIMONY REGARDING THE USE OF MULTIPLE TEST PERIODS?

A9. Yes. The Company expresses several concerns over the TRA's use of multiple test periods in their last rate case.[3] However, the underlying cause of the Company's concerns with multiple test periods appears to rest with the normalization adjustments that either may, or may not have been taken into

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[1] TRA Docket No. 08-00039.
[2] See Attachment WHN-2 for examples from Dockets 93-06946, 92-02987 and 89-10491.
[3] Direct testimony of Company witness Miller, Page 17.

account in order to produce the attrition period or going level amounts to set rates with.

In this case, both the Company and the CAPD have used the same attrition period for setting rates (the twelve months ending December 31, 2011) even though they are proposing two different test periods. Naturally, the normalizing adjustments (eg. compound growth rates, compound inflation rates) would be not be identical since the starting point of the test period adjustments are different, even though the attrition period is the same. It therefore appears to me that the Company's arguments against the use of multiple test periods are really just an excuse to avoid investigating another party's normalizing adjustments.

Again, the CAPD would urge the TRA to completely adopt its proposed test period for the twelve months ended September 30, 2010 which contains the most recent and relevant information for setting rates during the attrition period. However, if the TRA is inclined to consider the use of multiple test periods, then the CAPD would urge the TRA to closely examine the underlying normalization adjustments from each party.

II. COST OF SERVICE STUDY

Q10. PLEASE BRIEFLY EXPLAIN THE PURPOSE OF THE ALLOCATION PROCESS IN THE COMPANY'S COST OF SERVICE STUDY.

A10. The purpose of any Cost of Service Study ("COSS") is to arrive at the cost of serving each customer class and present a systematic approach to allocating this cost (or total revenue requirement) to the different classes of customers. The COSS then provides a measure of guidance for the TRA to consider how to best adjust individual rates for each customer class to produce the total revenue requirement. In this case, the Company has developed a COSS using twenty-three (23) separate allocation factors.[4]

Q11. DO YOU AGREE WITH THE COMPANY'S COSS METHODOLOGY IN THIS CASE?

A11. No. Many components of the 23 allocation factors used in the Company's COSS are based on judgment without any substantiation whatsoever.[5] In my opinion, it is unacceptable to use "judgment factors" for a COSS because the result is a COSS that cannot be independently verified or corroborated.

[4] Direct testimony and exhibits of Company witness Herbert, Schedule C.
[5] Direct testimony of Company witness Herbert, page 10, lines 1 – 5.

However, the Company has chosen not to implement the results of its COSS for setting proposed rates. Instead, the Company proposes to "…increase service charges and volumetric rates so that each class receives approximately the same increase.[6] This approach to rate design is also acceptable to the Consumer Advocate. Therefore, our objection to the Company's COSS becomes a moot issue for this case since its results are not proposed to be implemented. Nevertheless, the CAPD would still like to go on record in this docket as opposing the Company's COSS methodology in order to avoid Company objections to its implementation in future rate cases.

<u>III. WEATHER NORMALIZATION ADJUSTMENT</u>

Q12. MR. NOVAK, ARE YOU FAMILIAR WITH THE WEATHER NORMALIZATION MECHANISMS ADOPTED BY TRA REGULATED UTILITIES?

A12. Yes. I helped develop the current Weather Normalization Adjustment (WNA) rules for gas utilities in Tennessee.[7] I also presented testimony on the development for the first ever approved WNA for a public utility in the state of Virginia.[8] In addition, I developed the TRA Staff's WNA model, and I have testified on weather normalization issues and procedures in a number of rate cases.

[6] Direct testimony of Company witness Herbert, page 11, lines 8 – 10.
[7] Docket G-86-1.
[8] Case Number PUE-02-00237 before the Virginia State Corporation Commission.

Q13. HAS THIS AGENCY EVER EXPLICITLY OR TACITLY APPROVED A WEATHER NORMALIZATION ADJUSTMENT FOR TAWC?

A13. No. To my knowledge neither the TRA nor the Tennessee Public Service Commission ("TPSC") have ever directly addressed or approved a WNA for TAWC. The Company has discussed this issue at length in their direct testimony[9] and many of their conclusions are incorrect. I believe that I have some unique information on the history of this issue that may help the TRA better understand its evolution into the current case.

Q14. PLEASE DISCUSS THE CONSIDERATION OF WEATHER NORMALIZATION IN THE COMPANY'S 1989 RATE CASE.

A14. In Docket 89-15388, the Company filed a rate case for an increase of $2,609,365 in revenues. Unfortunately for the Company, they made a number of calculation errors to their own detriment in their development of this case which they never corrected.[10] Although not a part of their filed rate case, the Company attempted to demonstrate to the Staff the unfavorable impact of abnormal weather on their financial results in order to alleviate certain omissions from their case. **<u>This was the first occasion that a weather adjustment for TAWC had ever been discussed by the Company</u>**.

[9] Direct testimony of Company witness Miller, page 50.
[10] See Attachment WHN-3.

In order to fully examine the impact of weather on the Company's rate case, I adapted the Staff's weather normalization model for gas utilities. The Staff's weather model considered the impact of heating degree days, cooling degree days and rainfall on the Company's residential and commercial sales per customer through a series of linear regressions. The results of this study would have actually been to ***increase*** rather than reduce the Company's pro forma revenues (with a resulting decrease to the amount of the revenue request). However, the correlation factors from my analysis were too poor to suggest a direct causal relationship between weather and customer water usage, so I therefore disregarded its results.

I provided a copy of my analysis to the Company in order to dispute their claims as to the impact of abnormal weather on water sales. However, the other adjustments to the Company's case that were being considered by the Staff in this case were not enough to overcome the impact of the Company's own detrimental omissions. As a result, I recommended that the Company's rate request be granted in full as stated earlier, and therefore the issue of weather normalization was moot.

Q15. PLEASE DISCUSS THE CONSIDERATION OF WEATHER NORMALIZATION IN THE COMPANY'S 1991, 1993 AND 1996 RATE CASES.

A15. In Dockets 91-05224, 93-02943 and 96-00969 the Company witnesses adopted the Staff's weather normalization model that I had provided to them in the 1989 rate case.[11] However, my own recollection is that the Staff continued to exclude the impacts of weather since the resulting linear regression correlations continued to show no material direct causal relationship between weather and water sales. In any event, the issues in these three cases were settled between the parties **with no recognition of weather normalization**.

Q16. WHY IS IT IMPORTANT FOR THE TRA TO BE AWARE OF THE CONSIDERATION OF WEATHER NORMALIZATION IN THESE OLDER CASES?

A16. Because the Company now states in their direct testimony that the TRA Staff first proposed a weather adjustment for TAWC.[12] In addition, the Company has stated in testimony before the Kentucky Public Service Commission that weather normalization has been used in Tennessee since 1989.[13] As described above, this is certainly not the case. Also, while the Company may well have indeed filed each of their rate cases since 1991 with adjustments for weather, all of these rate cases except for the last two were resolved through "black box" settlements with no specific resolution of any weather normalization issue. In addition, in the 2006 and

[11] See Attachment WHN-4
[12] Direct testimony of Company witness Miller, page 50, lines 2 – 16.
[13] See CAPD Data Request #123.

2008 rate cases that were fully litigated, the Company's proposed WNA adjustments were never explicitly adopted by the TRA.

Q17. HAVE YOU REVIEWED THE WNA PROPOSED BY COMPANY WITNESS SPITZNAGEL IN THE CURRENT CASE?

A17. Yes. Dr. Spitznagel uses a series of regression analyses based upon the individual months of the year and the Palmer Modified Drought Index. Based on Dr. Spitznagel's weather study, the Company has reduced the residential and commercial water sales for their test period by 98,697 cubic feet, resulting in a corresponding revenue reduction of $318,523.[14]

Q18. DO YOU AGREE WITH DR. SPITZNAGEL'S PROPOSED WEATHER NORMALIZATION ADJUSTMENT?

A18. No. In my opinion, the results of Dr. Spitznagel's proposed weather normalization adjustments are of insufficient quality for consideration within a rate case. Specifically, the correlation factors from Dr. Spitznagel's regression analyses are too low to support a direct causal link between weather and customer sales volumes. Interestingly, this is exactly the same conclusion that I first came to in the Company's 1989 rate case described above.

[14] See TRA Data Request #102.

Q19. PLEASE FURTHER EXPLAIN THE TERM "CORRELATION" AS IT IS APPLIED HERE FOR WEATHER NORMALIZATION STUDIES.

A19. Simply put, correlation refers to the variations in sales volumes that can be explained by changes in weather. A correlation factor of 1.00 would mean that 100% of the variation in sales volume is explained by weather. Likewise, a correlation of 0.00 would mean that weather has no impact on sales volumes.

Q20. WHAT CORRELATION FACTOR WAS ACHIEVED BY THE COMPANY'S PROPOSED WEATHER NORMALIZATION?

A20. The Company's weather normalization produces an average correlation of 55.70% for residential sales and 30.28% for commercial sales as shown in the table below. In my opinion, these correlation averages are materially deficient to be used as a basis for setting customer rates.

Tennessee-American Water Company Company Weather Normalization Regression Correlation Factors[15]		
Month	**Residential**	**Commercial**
January	63.48%	23.97%
February	34.16%	2.66%
March	46.00%	9.71%
April	61.95%	26.89%
May	57.85%	7.51%
June	30.21%	12.76%
July	18.63%	51.23%
August	61.43%	31.55%
September	61.78%	74.80%
October	73.79%	42.71%
November	87.68%	64.44%
December	71.48%	15.10%

[15] Direct testimony of Company witness Spitznagel, Appendix B.

Average	**55.70%**	**30.28%**

Q21. WHAT IS YOUR BASIS FOR STATING THAT THESE CORRELATION AVERAGES ARE TOO LOW FOR USE IN SETTING CUSTOMER RATES?

A21. The TRA has long recognized a causal relationship between weather and sales for gas utilities. As shown in the table below, the weather normalization correlation averages from the last rate cases[16] for the major gas utilities under the TRA's jurisdiction are 96.63%, 97.72% and 97.46%. These superior correlation factors indicate a strong causal link between gas sales and weather. Although weather can help explain a portion of water sales variances for TAWC (on average 55.70% for residential and 30.28% for commercial), it is not significant enough to be used as a basis for setting customer rates.

Comparison of Gas Utility Weather Normalization Regression Correlation Factors	
Utility/Customer Class	**Correlation Factor**
Chattanooga Gas Company:[17]	
Residential	99.94%
Commercial	99.35%
C-1	96.58%
C-2	99.32%
Multi-Family	87.98%
Average	**96.63%**
Nashville Gas Company:[18]	

[16] Weather normalization was discontinued in the 2009 rate case for Chattanooga Gas Company with the implementation of a decoupling mechanism. The data presented is from their 2006 rate case.
[17] Attachment WHN-5.
[18] Attachment WHN-6.

Residential	98.65%
Residential-Value	98.32%
Residential-Standard	98.47%
Commercial	99.17%
Small General Service-Value	97.81%
Small General Service-Standard	98.41%
Medium General Service-Value	93.00%
Medium General Service-Standard	97.94%
Average	**97.72%**
Atmos Energy Corporation:[19]	
Residential-Bristol	97.45%
Residential-Knoxville	98.78%
Residential-Nashville	97.49%
Residential-Paducah	98.88%
Commercial-Bristol	97.43%
Commercial-Knoxville	94.79%
Commercial-Nashville	97.16%
Commercial-Paducah	97.73%
Average	**97.46%**

Q22. DOES THIS COMPLETE YOUR TESTIMONY?

A22. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available.

[19] Attachment WHN-7.

CERTIFICATE OF SERVICE

I hereby certify that a copy of *Direct Testimony of William H. Novak on Behalf of the Consumer Advocate & Protection Division of the Tennessee Attorney General's Office* was provided to the persons listed below via first class U.S. Mail, postage prepaid, this 5th day of January, 2011.

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ATTACHMENT

3

WHN CONSULTING

19 Morning Arbor Place
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August 30, 2006

Dr. R. Michael Browder
General Manager
Bristol Tennessee Essential Services
PO Box 549
Bristol, TN 37621-0549

RE: Audit of BTES Cost Allocation Manual

Dear Dr. Browder:

In accordance with the agreed upon procedures filed with the Tennessee Regulatory Authority ("TRA" or the "Authority") on May 22, 2006 in Docket 05-00251, we have examined the Cost Allocation Manual (the "CAM") of Bristol Tennessee Essential Services ("BTES" or the "Company").

As stated in the agreed upon procedures, the purpose of this examination was to:

1. Determine if the methods used to allocate costs to the appropriate business units are sufficient so that the operating results of each business unit present fairly, in all material respects, the financial position and results of operations of each business unit;
2. Determine if the CAM produces fair and reasonable results; and
3. To the extent consistent with purposes (1) and (2), minimize the time and expense necessary to record and audit the transactions.

With these requirements in mind, this examination does not provide an opinion on whether the financial statements of BTES taken as a whole are fairly presented in all material respects, but whether the CAM itself was developed in a manner that will produce fair and reasonable results. In addition, this examination does not include a review to determine whether the Company is in compliance with the CAM, and instead only examines the development of the CAM itself.

We feel that the two findings detailed in the audit report have been adequately addressed by the Company's management and are immaterial to the overall results of the CAM. In our opinion, subject to the limitations detailed above, the methodology described in the CAM to allocate common costs to the different business units of BTES is sufficient so that the financial position and results of operations for each business unit will be presented fairly in all material respects when these procedures are employed. In addition, the time and expense necessary to record, maintain and audit the ongoing changes to the CAM appear to be minimal.

Our complete audit report is attached. If you have any questions, please let me know.

Sincerely,

William H. Novak

BRISTOL TENNESSEE ESSENTIAL SERVICES
AUDIT OF COST ALLOCATION MANUAL METHODOLOGY

PRPARED BY WHN CONSULTING
AUGUST 30, 2006

BRISTOL TENNESSEE ESSENTIAL SERVICES
AUDIT OF COST ALLOCATION MANUAL METHODOLOGY
TABLE OF CONTENTS

1. BACKGROUND

On March 21, 2006, the Tennessee Regulatory Authority ("TRA") issued its order approving the application of Bristol Tennessee Essential Services ("BTES" or the "Company") for a Certificate of Convenience and Necessity ("CCN") to provide competing local telecommunication services.[1] Final approval of the CCN by the TRA was conditioned on a Settlement Agreement (the "Agreement") dated February 10, 2006, between BTES and the other parties in this docket.

One component of the Agreement requires BTES to submit to an independent audit of its cost allocation procedures. According to the Agreement, the purpose of the audit is to:

1. Determine if the methods used to allocate costs to the appropriate business units are sufficient so that the operating results of each business unit present fairly, in all material respects, the financial position and results of operations of each business unit;

2. Determine if the Cost Allocation Manual ("CAM") produces fair and reasonable results; and

3. To the extent consistent with purposes (1) and (2), minimize the time and expense necessary to record and audit the transactions.

With these requirements in mind, this audit does not provide an opinion on whether the financial statements taken as a whole are fairly presented in all material respects, but whether the CAM itself was developed in a manner that will produce fair and reasonable results. In addition, this audit does not include an examination to determine whether the Company is in compliance with the CAM, and instead only examines the development of the CAM itself.

On April 17, 2006, BTES executed a contract with WHN Consulting ("WHN") for an independent audit of its cost allocation procedures. On May 22, 2006, a work plan for the completion of the audit was submitted to the TRA for its consideration by WHN.

[1] TRA Docket No. 05-00251.

2. PROCEDURES

We began our examination with a review of the existing legal statutes, rules and regulations for the allocation of costs by BTES. The existing requirements for allocations are as follows:

1. Loans made by one business unit to another must be at the highest rate of interest on earned or invested funds in accordance with TCA § 7-52-402 and § 7-52-603.
2. The Telephone business unit must make in lieu of tax payments and record state, local and federal taxes in accordance with TCA § 7-52-404.
3. The Telephone business unit must pay an amount for attachments to poles owned by other business units at the highest rate charged to any other entity in accordance with TCA § 7-52-405 and § 7-52-603.
4. The Cable & Internet business unit must make tax payments in accordance with TCA § 7-52-606.
5. The Company must comply with the Code of Federal Regulations, Title 47, Section 64.901 through 64.905 regarding allocation of costs by the Federal Communications Commission.
6. The Company must comply with the Code of Federal Regulations, Title 47, Section 32.27 regarding affiliate transactions by the Federal Communications Commission.

In addition to these requirements, the Company must also comply with the terms and conditions of the Agreement with the other parties in TRA Docket 05-00251.

We next asked the Company to provide us with their workpapers and supporting calculations for the CAM through a series of data requests. In addition, we conducted an on-site inspection and review of the cost allocation procedures at the Company's offices in Bristol, Tennessee.

Finally, we identified the common costs to be allocated. For this process, BTES provided us with a set of pro forma consolidated financial statements that reflected the actual operating results of the electric business unit for the twelve months ended June 30, 2005 along with the projected operating results of the Cable & Internet business unit and the Telephone business unit for their third year of operation. We then examined the specific allocation factors that BTES proposed to apply to the common costs contained within these consolidated financial statements.

The results of our examination of each individual allocation method are presented herein.

3.1 BALANCE SHEET ALLOCATIONS – PLANT IN SERVICE

The Company has calculated their total consolidated pro forma plant in service in the CAM to be $92,320,823.[2] This amount was calculated by taking the directly assigned plant in service for each business unit[3] and adding an allocated amount of the projected total joint plant in service[4] and existing fiber optic infrastructure plant in service.[5] The results of these pro forma calculations are presented below.

Plant in Service:	Electric	Cable & Internet	Telephone	Total
Directly Assigned Plant	$66,193,627	$8,370,001	$1,536,155	$76,099,783
Joint Plant	6,823,256	3,701,616	2,089,622	12,614,494
Existing Fiber Infrastructure	2,356,498	799,000	451,048	3,606,546
Total	**$75,373,381**	**$12,870,617**	**$4,076,825**	**$92,320,823**
Percentage	**81.64%**	**13.94%**	**4.42%**	**100.00%**

The allocation of the Joint Plant in Service to each business unit based on the number of homes passed (potential customers) appears appropriate. It matches the common plant that can't be specifically identified with the number of potential customers that will theoretically provide future revenues to recover the cost of the Joint Plant in Service.

Likewise, the allocation of the Existing Fiber Optic Infrastructure based on the expected number of customers after the third year of operations also appears appropriate. This existing plant is allocated based on the near term, full build-out of operations by the Cable & Internet and Telephone business units.

In addition to the Joint Plant in Service, when applicable, the poles owned by the Electric business unit are leased to the Cable & Internet and Telephone business units at the highest rate paid by an outside party for comparable pole attachments. This lease rate is appropriate and in accordance with TCA § 7-52-405 and § 7-52-603.

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[2] BTES Cost Allocation Manual, Appendix C, Page C-5.

[3] The directly assigned plant consists of the actual Electric plant at June 30, 2005 along with the projected Cable & Internet and Telephone plant after the first full year of operations.

[4] The total joint plant in service is an estimate of the fiber optic cable and electronics that will be added to the system over a four-year period. It is allocated to each business unit based on the number of homes passed by each business unit.

[5] The existing fiber optic infrastructure plant in service represents the balance at June 30, 2005 and is allocated to the different business units based on the expected number of customers in each business unit after the third year of operations.

4.1 INCOME STATEMENT ALLOCATIONS -- SUBSTATION ALLOCATOR

The Company uses the Substation Allocator to allocate those common expenses related to the systematic recovery of the plant in service devoted to the joint fiber infrastructure.

The Substation Allocator is calculated by taking the substation equipment related to the joint fiber infrastructure for each business unit, and dividing it by the total of all substation equipment related to the joint fiber infrastructure of BTES.

In developing the CAM, the Company calculated pro forma Substation Allocators of 61.02%, 33.37%, and 5.71% respectively for the Electric, Cable & Internet, and Telephone business units.[6] These factors were calculated by first allocating the total of the joint substation equipment to the different business units using the Joint Substation Equipment Allocators, and then adding in the direct assigned substation equipment to each business unit. These pro forma allocation factors were calculated by the Company as follows:

	Allocator[7]	Total
Joint Substation Equipment		**$208,893**
Electric	74.61%	$155,864
Cable & Internet	18.52%	38,694
Telephone	6.86%	14,335
Total	**100.00%**	**$208,893**

	Joint Equipment	Direct Equipment	Total Equipment	Substation Percentage
Electric	$155,864	$0	$155,864	61.02%
Cable & Internet	38,694	46,529	85,223	33.37%
Telephone	14,335	0	14,335	5.61%
Total	**$208,893**	**$46,529**	**$255,422**	**100.00%**

[6] BTES Cost Allocation Manual, Appendix C, Page C-6.

[7] During the course of this audit, the Company discovered an error in the original Substation Allocation calculation. The corrected allocation factors of Joint Substation Equipment are 56.59%, 27.75% and 15.66% respectively for the electric, cable & internet, and telephone business units and are based on the total Joint Plant and the Existing Fiber Infrastructure Plant allocated to each business unit. However, the methodology for calculating these factors remains the same.

In developing the CAM, the Company allocated the following pro forma amounts with the Substation Allocator:

Substations:	Electric	Cable & Internet	Telephone	Total
Depreciation	$1,952.64	$1,067.84	$179.52	$3,200.00
Taxes	1,525.50	834.25	140.25	2,500.00
Return On Investment	6,327.77	3,460.47	581.76	10,370.00
Total	**$9,805.91**	**$5,362.56**	**$901.53**	**$16,070.00**
Percentage	**61.02%**	**33.37%**	**5.61%**	**100.00%**

The Return on Investment ("ROI") component of the allocation represents the carrying costs of the substation assets owned by the Electric business unit that are used by the Cable & Internet and Telephone business units. The ROI applied is 6.65%, and is based on the consolidated return earned by BTES on its total net investment in utility plant. The ROI billing is necessary for the Company to comply with the terms of TCA § 7-52-402 and § 7-52-603 regarding loans from one business unit to another. However, the book entry to record the ROI allocated to the Electric business unit ($6,327.77) needs to be reversed out since these assets are already recorded on the Electric business unit's books.[8]

The Substation Allocator is the appropriate allocator of those expenses related to the systematic recovery of the fiber infrastructure plant in service. The Substation Allocator correctly recognizes the fiber infrastructure plant devoted to each business unit and then allocates those common expenses related to this plant to each of the business units.

[8] See Section 5 for a further discussion on this issue.

4.2 INCOME STATEMENT ALLOCATIONS -- SERVICES ALLOCATOR

The Company uses the Services Allocator to allocate a number of common administrative expenses related to supporting all of the business units.

The Services Allocator is calculated by taking the number of services (active customers) for each business unit, and dividing it by the total of all business unit services of BTES.

In developing the CAM, the Company calculated pro forma Services Allocators of 65.34%, 22.15%, and 12.51% respectively for the Electric, Cable & Internet, and Telephone business units. These factors were calculated by first taking the existing number of electric customers and then adding the projected number of cable & internet and telephone customers after three years of build-out. The total projected services were then divided into the services for each individual business unit to determine each allocation factor. These pro forma allocation factors were calculated by the Company as follows:

	Electric	Cable & Internet	Telephone	Total
Total Services	32,000	10,850	6,125	48,975
Percentage	**65.34%**	**22.15%**	**12.51%**	**100.00%**

In developing the CAM, the Company allocated the following pro forma amounts with the Services Allocator:

Services Allocator:	**Electric**	**Cable & Internet**	**Telephone**	**Total**
Postage	82,328.40	27,909.00	15,762.60	126,000.00
Bills	32,931.36	11,163.60	6,305.04	50,400.00
Delinquents	5,488.56	1,860.60	1,050.84	8,400.00
Support	39,988.08	13,555.80	7,656.12	61,200.00
Bristol Telephone	791.92	268.46	151.62	1,212.00
Online	7,840.80	2,658.00	1,501.20	12,000.00
Legal	25,482.60	8,638.50	4,878.90	39,000.00
HP Support	5,496.40	1,863.26	1,052.34	8,412.00
Loomis Fargo	4,116.42	1,395.45	788.13	6,300.00
Pitney Bowes	3,267.00	1,107.50	625.50	5,000.00
Postmaster	15,681.60	5,316.00	3,002.40	24,000.00
Collection Expense	0.00	0.00	0.00	0.00
Total	**$223,413.14**	**$75,736.17**	**$42,774.69**	**$341,924.00**
Percentage	**65.34%**	**22.15%**	**12.51%**	**100.00%**

The Services Allocator is an appropriate allocator of the common administrative expenses that can't be separated into a specific business unit. The Services Allocator correctly recognizes the number of active customers for each business unit, and then allocates those common administrative expenses to each of the business units based upon the number of services supplied.

4.3 INCOME STATEMENT ALLOCATIONS -- GENERAL ALLOCATOR

The Company uses the General Allocator to allocate the common operations & maintenance ("O&M") expenses related to supporting all of the business units.

The General Allocator is calculated by taking the O&M expense for each business unit, and dividing it by the total O&M expense for all business units of BTES.

In developing the CAM, the Company calculated pro forma General Allocators of 81.99%, 9.13%, and 8.88% respectively for the Electric, Cable & Internet, and Telephone business units.[9] These factors were calculated by first taking the pro forma O&M expense for each business unit and subtracting those O&M expenses that were to be allocated with the General Allocator. The total net O&M expense was then divided into the net O&M expense each individual business unit to determine each allocation factor. These pro forma allocation factors were calculated by the Company as follows:

	Total O&M Expense	**Less Allocated Expenses**	**General Allocator**	**Percent**
Electric	$5,250,287	$810,934	$4,439,353	81.99%
Cable & Internet	584,520	90,355	494,165	9.13%
Telephone	568,404	87,098	481,306	8.88%
Total	**$6,403,211**	**$988,387**	**$5,414,824**	**100.00%**

[9] BTES Cost Allocation Manual, Appendix C, Page C-1. Note that a rounding error exists in the CAM where the electric business unit states an allocation factor of 81.98% that should be 81.99%, and the telephone business unit states an allocation factor of 8.89% that should be 8.88%.

In developing the CAM, the Company allocated the following pro forma amounts with the General Allocator:

	Electric	Cable & Internet	Telephone	Total
General Allocator:				
Water and Sewer	1,151.03	128.17	124.80	1,404.00
Trash Collection	1,934.80	215.45	209.79	2,360.04
Extermination	305.00	33.96	33.07	372.03
Elevator Maintenance	2,709.56	301.72	293.79	3,305.07
Maintenance	22,532.49	2,509.11	2,443.15	27,484.75
Depreciation	18,754.33	2,088.39	2,033.49	22,876.21
Taxes	14,132.54	1,573.73	1,532.36	17,238.63
Return on Investment	59,803.98	6,659.47	6,484.42	72,947.87
Audit Expense	24,597.00	2,739.00	2,667.00	30,003.00
Dir. & Officers Liability	35,978.85	4,006.43	3,901.11	43,886.39
General Liability	21,348.47	2,377.26	2,314.77	26,040.50
Crime	10.17	1.13	1.10	12.40
Umbrella	48,843.08	5,438.92	5,295.95	59,577.95
Board Members	23,613.12	2,629.44	2,560.32	28,802.88
Total	**$275,714.42**	**$30,702.18**	**$29,895.12**	**$336,311.72**
Percentage	**81.99%**	**9.13%**	**8.88%**	**100.00%**

The Return on Investment ("ROI") component of the allocation represents the carrying costs of the plant assets owned by the Electric business unit that are used by the Cable & Internet and Telephone business units.[10] The ROI applied is 6.65%, and is based on the consolidated return earned by BTES on its total net investment in utility plant. The ROI billing is necessary for the Company to comply with the terms of TCA § 7-52-402 and § 7-52-603 regarding loans from one business unit to another. However, the book entry to record the ROI allocated to the Electric business unit ($59,803.98) needs to be reversed out since these assets are already recorded on the Electric business unit's books.[11]

The General Allocator is an appropriate allocator of the common O&M expenses that can't be separated into a specific business unit. The General Allocator correctly segregates the common O&M expenses based on the net direct O&M expenses of all business units.

[10] These plant assets include structures and improvements, communications, office furniture, power operating equipment and tool, shop and garage equipment.

[11] See Section 5 for a further discussion on this issue.

4.4 INCOME STATEMENT ALLOCATIONS -- EMPLOYEE HOURS ALLOCATOR

The Company uses the Employee Hours Allocator to allocate the common ancillary employee expenses related to supporting all of the business units.

The Employee Hours Allocator is calculated by taking the projected pro forma employee hours for each business unit, and dividing it by the total projected pro forma employee hours for all business units of BTES.

In developing the CAM, the Company calculated pro forma Employee Hours Allocators of 79.86%, 13.12%, and 7.02% respectively for the Electric, Cable & Internet, and Telephone business units. These factors were calculated by first taking the existing number of employee hours for the electric business unit, and then adding the projected employee hours of the cable & internet and telephone business units after three years of build-out. The total employee hours were then divided into the projected employee hours for each individual business unit to determine each allocation factor. These pro forma allocation factors were calculated by the Company as follows:

	Electric	Cable & Internet	Telephone	Total
Employee Hours	114,617	18,833	10,070	143,520
Percentage	**79.86%**	**13.12%**	**7.02%**	**100.00%**

In developing the CAM, the Company allocated the following pro forma amounts with the Employee Hours Allocator:

Employee Hours Allocator:	**Electric**	**Cable & Internet**	**Telephone**	**Total**
Verizon	11,979.00	1,968.00	1,053.00	15,000.00
KMC Telcom	16,291.44	2,676.48	1,432.08	20,400.00
Desktop Coop	64,207.44	10,548.48	5,644.08	80,400.00
Picnic	3,240.35	532.35	284.84	4,057.54
Awards Banquet	3,733.75	613.41	328.21	4,675.37
Christmas Party	9,096.78	1,494.49	799.64	11,390.91
Office Supplies	147,581.28	24,245.76	12,972.96	184,800.00
Total	**$256,130.04**	**$42,078.97**	**$22,514.81**	**$320,723.82**
Percentage	**79.86%**	**13.12%**	**7.02%**	**100.00%**

The Employee Hours Allocator is an appropriate allocator of the common ancillary employee expenses that can't be separated into a specific business unit. The Employee Hours Allocator correctly segregates the common employee expenses based on the total hours worked in all business units.

4.5 INCOME STATEMENT ALLOCATIONS -- VEHICLE ALLOCATOR

The Company uses the Vehicle Allocator to allocate the cost of their vehicle fleet to the different business units.

The Company allocates the total cost of each vehicle by using the same allocation method applied to the employee that the vehicle is assigned. The Vehicle Allocator is calculated by taking the average for each employee's Salary, Wage & Benefit Allocator that have vehicles assigned to them. In developing the CAM, the Company calculated pro forma Vehicle Allocators of 87.90%, 8.24%, and 3.86% respectively for the Electric, Cable & Internet, and Telephone business units.[12] These pro forma allocation factors were calculated by the Company as follows:

Vehicle Number	Allocation[13] Method	Electric	Cable & Internet	Telephone	Total
16	General	81.98%	9.13%	8.89%	100.00%
30	General	81.98%	9.13%	8.89%	100.00%
31	Dept Avg	80.36%	9.84%	9.80%	100.00%
32	C&I Cust	82.29%	12.57%	5.14%	100.00%
34	Time Sheet	20.00%	70.00%	10.00%	100.00%
35	Time Sheet	96.00%	2.00%	2.00%	100.00%
36	Time Sheet	96.00%	2.00%	2.00%	100.00%
37	Time Sheet	96.00%	2.00%	2.00%	100.00%
38	Time Sheet	65.00%	25.00%	10.00%	100.00%
40	Time Sheet	96.32%	2.20%	1.48%	100.00%
41	Time Sheet	98.00%	1.00%	1.00%	100.00%
43	Time Sheet	98.50%	1.00%	0.50%	100.00%
44	Estimated	92.00%	6.00%	2.00%	100.00%
48	Time Sheet	96.00%	2.00%	2.00%	100.00%
59	Time Sheet	98.50%	1.00%	0.50%	100.00%
60	Time Sheet	98.00%	1.00%	1.00%	100.00%
61	Time Sheet	98.00%	1.00%	1.00%	100.00%
63	Time Sheet	98.50%	1.00%	0.50%	100.00%
70	General	81.98%	9.13%	8.89%	100.00%
73	Time Sheet	98.50%	1.00%	0.50%	100.00%
79	Time Sheet	92.00%	5.00%	3.00%	100.00%
Average		**87.90%**	**8.24%**	**3.86%**	**100.00%**

[12] BTES Cost Allocation Manual, Appendix C, Page C-3.
[13] See Section 4.6 Income Statement Allocations – Salaries, Wages & Benefits, for a full description of each allocator.

In developing the CAM, the Company allocated the following vehicle costs through the individual pro forma allocations of each vehicle:

Vehicle Allocator:	Electric	Cable & Internet	Telephone	Total
Auto Fleet Expense	$160,043.02	$15,002.89	$7,028.05	$182,073.96
Total	**$160,043.02**	**$15,002.89**	**$7,028.05**	**$182,073.96**
Percentage	**87.90%**	**8.24%**	**3.86%**	**100.00%**

The individual components of the Vehicle Allocator are the most appropriate allocator of the auto fleet expense since it matches the allocation to each of the business units for each employee that is assigned a vehicle.

Finding #1:
The Company needs to separately calculate and allocate the Return on Investment ("ROI") related to the net book value of its vehicle fleet to the different business units.

The ROI represents the carrying cost of the vehicle fleet owned by the Electric business unit and used by the Cable & Internet and Telephone business units. The ROI that should be applied is the consolidated return earned by BTES on its total net investment in utility plant which is 6.65% for the twelve months ended June 30, 2005. The ROI billing is necessary for the Company to comply with the terms of TCA § 7-52-402 and § 7-52-603 regarding loans from one business unit to another.

The ROI calculation for the vehicle fleet is similar in concept to the ROI components allocated by the Company for the Substation Allocator (Section 4.1) and the General Allocator (Section 4.3). The ROI for the vehicle fleet is calculated as follows:

Gross Vehicle Plant @ June 30, 2005	$1,947,755.91
Less Accumulated Depreciation on Vehicle Plant @ June 30, 2005	1,449,394.96
Net Vehicle Plant @ June 30, 2005	$498,360.95
Consolidated Rate of Return Factor @ June 30, 2005	6.65%
Vehicle ROI to be allocated to the different business units	**$33,141.00**

The Vehicle ROI can then be allocated to the different business units by applying the Vehicle Allocation factors as follows:

Vehicle Allocator:	Electric	Cable & Internet	Telephone	Total
Percentage	**87.90%**	**8.24%**	**3.86%**	**100.00%**
ROI	**$29,130.94**	**$2,730.82**	**$1,279.24**	**$33,141.00**

In order to maintain a constant vehicle allocation factor calculation, the ROI for the vehicle fleet should be calculated and applied separately from the other vehicle allocation factors. In addition, the book entry to record the ROI allocated to the Electric business unit ($29,130.94) needs to be reversed out since these assets are already recorded on the Electric business unit's books.[14]

<u>Company Response to Finding #1:</u>
The Company concurs with Finding #1 and will implement its recommendation on a prospective basis.

[14] See Section 5 for a further discussion on this issue.

4.6 INCOME STATEMENT ALLOCATIONS -- SALARIES, WAGES & BENEFITS

The Company has 69 employees whose time is allocated in accordance with the functions that they provide. These individual allocations produce a weighted average allocation for total salary, wages & benefits of 83.80%, 10.52% and 5.68% respectively for the Electric, Cable & Internet and Telephone business units. The individual allocation methods making up this total are presented and described below.

	Positions	Electric	Cable & Internet	Telephone	Total
Timesheets	37	87.03%	8.85%	4.11%	100.00%
General Allocator	8	81.98%	9.13%	8.89%	100.00%
Department Average	4	89.48%	5.51%	5.01%	100.00%
Estimated	1	92.00%	6.00%	2.00%	100.00%
Comm/Ind Customers	1	78.77%	17.32%	3.91%	100.00%
Materials Issued	1	97.50%	1.25%	1.25%	100.00%
Customer Activity	9	80.00%	10.00%	10.00%	100.00%
Total Services	2	65.34%	22.15%	12.51%	100.00%
Customer Calls	4	10.00%	70.00%	20.00%	100.00%
Vehicles	2	87.90%	8.24%	3.86%	100.00%
Total/Average	**69**	**83.80%**	**10.52%**	**5.68%**	**100.00%**

Timesheets:
The employees that directly assign their time to the different business units through timesheets include the Company's Foremen, Linemen, Groundmen, Apprentices, System Engineers, Meter Readers, Engineer Assistants, Network Supervisors, Technicians and Managers. Since these employees can track their time to a particular project or job within each business unit, the direct assignment of their time through timesheets is the most appropriate allocation method.

General Allocator:
This group of employees includes the General Manager, Accounting & Finance Director, General Accountants, Accounting Secretaries, Administrative Secretaries, Project Coordinator, and Maintenance employees. These employees perform multiple services for the different business units without any precise means of allocation. Therefore the General Allocator appears to be the most appropriate allocator of their time.

Department Average:
This group of employees includes the Director of Management Services, the Director of Operations & Safety, the Director of Engineering. The time for these employees is allocated to the different business units based on the department average of the employees that they supervise. The Engineering Secretary's time follows the Director of Operations & Safety. This method appears to be the most reasonable since the result of their time should most closely track the employees below them.

Estimated:
This group only includes the Supervisor of Purchasing and Stores. Since the addition of two new business units will make a material change on how this employee's time will be spent, an estimate was necessary for the time allocation to the different business units.

Commercial/Industrial Customers:
This group only includes the Business Development Manager. Because her time is spent supporting the needs of the existing commercial and industrial customers, this allocator is the most appropriate.

Materials Issued:
This group only includes the Company's storekeeper. Because the cost for this employee most closely tracks the material issued to each business unit, it is the most reasonable allocator.

Customer Activity:
This group includes the Company's Customer Service Representatives. Because their cost is most closely tied to taking orders for new service for each business unit, the customer activity of BTES is the most reasonable method to allocate their time.

Total Services:
This group includes the Company's Night Dispatchers. Because their time cannot be clearly tied to any specific activity, it is allocated to each business unit based on the total number of services or customers in each business unit.

Customer Calls:
This group includes the Company's Help Desk Personnel. Their cost is most directly tied to the number of calls from customers that they receive for each business unit.

Vehicles:
This group includes the Company's Garage Mechanics. Because their time cannot be clearly tied to any specific activity, it is allocated to the average number of vehicles within each business unit.

Applying each employee's projected individual rate of pay and benefits to their appropriate allocation factor produces a total pro forma salary, wage and benefit expense of $3,796,597; $476,595; and $257,402 respectively for the Electric, Cable & Internet, and Telephone business units as shown below.

	Positions	Electric	Cable & Internet	Telephone	Total
Timesheets	37	$2,349,045	$238,967	$110,996	$2,699,008
General Allocator	8	527,226	58,716	57,173	643,115
Department Average	4	305,462	18,808	17,100	341,370
Estimated	1	94,666	6,174	2,058	102,898
Comm/Ind Customers	1	65,225	14,342	3,238	82,805
Materials Issued	1	53,174	682	682	54,538
Customer Activity	9	241,563	30,195	30,195	301,954
Total Services	2	30,579	10,366	5,855	46,800
Customer Calls	4	12,480	87,360	24,960	124,800
Vehicles	2	117,177	10,985	5,146	133,307
Total	**69**	**$3,796,597**	**$476,595**	**$257,402**	**$4,530,594**

The Company has properly attempted to allocate each employee's time to the different business units based on a methodology that most closely matches that employee's duties. This method of allocation for Salaries, Wages & Benefits appears reasonable and most closely matches the cause of each employee's cost to the proper business unit.

<u>5.0 ROI ALLOCATION TO THE ELECTRIC BUSINESS UNIT:</u>

The Company presently includes a Return on Investment ("ROI") component in its calculation of the Substation Allocation Factor (Section 4.1) and the General Allocation Factor (Section 4.3).[15] The ROI component of these allocations represents the carrying costs of the various assets that are owned and used by the Electric business unit that are also used by the Cable & Internet and Telephone business units. The ROI applied is based on the consolidated return earned by BTES on its total net investment in utility plant. The ROI billing is necessary for the Company to comply with the terms of TCA § 7-52-402 and § 7-52-603 regarding loans from one business unit to another.

<u>Finding #2</u>:
The Company needs to reverse the entries in its financial statements that were made to allocate ROI to the Electric business unit.

Since the assets that are jointly used by the Electric, Cable & Internet and Telephone business units are already recorded on the books of the Electric business unit, there is no need to further allocate ROI to the Electric business unit. Therefore, the entries made to record the ROI allocated to the Electric business unit need to be reversed out. In order to maintain a constant allocation factor calculation for those allocation factors containing an ROI component, the ROI reversal should be calculated and applied separately.

<u>Company Response to Finding #2:</u>
The Company concurs with Finding #2 and will implement its recommendation on a prospective basis.

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[15] In addition, see Finding #1 contained in the discussion of the Vehicle Allocation Factor (Section 4.5).

6.0 CAM RECORDING, MAINTENANCE & AUDITING COST/BENEFIT ANALYSIS:

The final requirement of our examination was to ascertain whether the time and expense necessary to record, maintain and audit the transactions necessary to develop the CAM allocations is minimized. In this regard, we wanted to confirm that the Company had not taken on a costly and onerous procedure to keep its CAM up to date.

Currently, the Company updates its CAM allocations on a quarterly basis. We interviewed the Company's personnel responsible for updating the CAM allocation factors about this process. Their response to us was that all of the allocation factors only took two to three hours to update. To date, there has been no audit of the calculation of these CAM allocation factors.[16]

Given that the time involved in updating the allocation factors is only two to three hours on a quarterly basis, we conclude that the Company's internal cost to record and maintain the allocation factors is minimal. Although the Company has not yet conducted an audit of the updated quarterly allocation factors, we would expect this review to also be minimal.

[16] See Section 2(b) of the Settlement Agreement between BTES and the parties to TRA Docket 05-00251.

7.0 SUMMARY AND CONCLUSIONS

As described above, the Company's CAM uses the following allocators on its balance sheet.

Balance Sheet Allocators:	Electric	Cable & Internet	Telephone	Total
Plant in Service	81.64%	13.94%	4.42%	100.00%

In addition, the Company's CAM uses these allocators on its income statement.

Income Statement Allocators:	Electric	Cable & Internet	Telephone	Total
Substations Allocator	61.02%	33.37%	5.61%	100.00%
Services Allocator	65.34%	22.15%	12.51%	100.00%
General Allocator	81.99%	9.13%	8.88%	100.00%
Employee Hours Allocator	79.86%	13.12%	7.02%	100.00%
Vehicle Allocator (Various)	87.90%	8.24%	3.86%	100.00%
Wages & Benefits (Various)	83.80%	10.52%	5.68%	100.00%

Our examination of the allocation factors contained in the CAM revealed that the Company has attempted to most closely assign the appropriate cause of each cost (or cost driver) as the allocation method. We feel that the two findings detailed in the audit report have been adequately addressed by the Company's management and are immaterial to the overall results of the CAM. Although no single allocation method is perfect in assigning all common costs in all cases, in our opinion the methodology described in the CAM to allocate common costs to the different business units of BTES is sufficient so that the financial position and results of operations for each business unit will be presented fairly in all material respects when these procedures are employed.

In addition, the time and expense necessary for the Company's employees to record and maintain the ongoing changes to the CAM on a quarterly basis appear to be minimal.

ATTACHMENT

4

BEFORE
THE TENNESSEE REGULATORY AUTHORITY

	)	
Petition Of Tennessee American Water	)	
Company To Change And Increase	)	
Certain Rates And Charges So Far As To	)	
Permit It To Earn A Fair And Adequate	)	Docket No. 12-00049
Rate Of Return On Its Property Used And	)	
Useful In Furnishing Water Service To Its	)	
Customers	)	
	)	

DIRECT TESTIMONY
of
WILLIAM H. NOVAK

ON BEHALF OF
THE CONSUMER ADVOCATE AND PROTECTION DIVISION
OF THE
TENNESSEE ATTORNEY GENERAL'S OFFICE

August 27, 2012

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ATTACHMENTS

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.[1]

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am a Certified Management Accountant, and am also licensed to practice as a Certified Public Accountant.

My work experience has centered on regulated utilities for over 30 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee. I also served for two years as the Vice President of Regulatory Compliance for Sequent Energy Management, a natural

[1] State of Tennessee, Registered Accounting Firm ID 3682.

gas trading and optimization entity in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am testifying on behalf of the Consumer Advocate & Protection Division ("CAPD" or "the Consumer Advocate") of the Tennessee Attorney General's Office.

Q4. HAVE YOU PRESENTED TESTIMONY IN ANY PREVIOUS TENNESSEE AMERICAN WATER COMPANY RATE CASES?

A4. Yes. I presented testimony in Dockets U-86-7402, U-87-7534, 89-15388, 91-05224, 93-06946 and 10-00189 concerning Tennessee-American Water Company ("TAWC" or "the Company") rate cases as well as other generic tariff and rulemaking matters. In addition, I previously advised the TRA on issues in other TAWC rate cases in dockets where I did not present testimony.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A5. My testimony will support and address the CAPD's positions and concerns with respect to the Company's Petition. Specifically, I will address the following:

i. CAPD's proposed attrition period revenue calculations;
ii. CAPD's proposed attrition period rate base calculations;
iii. CAPD's position on TAWC's proposed Class Cost of Service Study; and

iv. CAPD's position on TAWC's special cost recovery proposals.

Q6. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A6. I have reviewed the Company's Rate Case Application as filed on June 1, 2012, along with the testimony and exhibits presented with their filing. In addition, I have reviewed the Company's workpapers supporting their attrition period revenues, rate base and cost of service study. I have also reviewed the Company's responses to the relevant data requests submitted by the TRA as well the Company's responses to CAPD's discovery requests in these same areas.

Q7. WHAT TEST PERIOD AND ATTRITION PERIOD HAS THE CAPD ADOPTED FOR THIS CASE?

A7. The Company has proposed the twelve months ended December 31, 2011 as its test period with attrition adjustments through the 12 months ending November 30, 2013. Both of these review periods appear reasonable. Therefore, the CAPD has adopted both the Company's proposed test period and attrition period for this case.

Q8. WHAT IS THE CAPD'S REVENUE DEFICIENCY CALCULATION FOR THIS CASE?

A8. As shown on CAPD Exhibit, Schedule 1, the CAPD's revenue deficiency calculation required to produce the 6.94% overall return recommended by Dr. Klein is approximately $2.8 million.

I. ATTRITION PERIOD REVENUES

Q9. MR. NOVAK, PLEASE DESCRIBE THE MAJOR AREAS OF DIFFERENCE BETWEEN THE COMPANY'S AND CAPD'S CALCULATION OF ATTRITION PERIOD REVENUES.

A9. As shown on CAPD Exhibit, Schedule 9, the difference between the Company and the CAPD's revenue calculations are approximately $800,000 out of approximate $43 million. Although the Company and the CAPD have used different methods to project revenues, the final results are closely related as shown on CAPD Exhibit, Schedule 9, with the primary differences due to the Company's error in calculating residential customer growth, errors in calculating sewer billing revenues and different methodologies used to project customer usage.

Q10. PLEASE DISCUSS THE COMPANY'S ERROR IN PROJECTING CUSTOMER GROWTH.

A10. The Company intended to include an increase in their case of 45 residential customers per month for customer growth.[2] However, the Company appears to have mistakenly increased the test period amount bills by 11,925 bills in their

[2] Company response to TRA Data Request, Item 9.

residential revenue calculation.[3] To correct this error, the CAPD has only included the actual test period bill count in its forecast.

Q11. PLEASE DISCUSS THE COMPANY'S ERROR IN CALCULATING SEWER BILLING REVENUES.

A11. As the TRA is aware, the Company recently discontinued third-party billing for sewer service providers.[4] Instead, the Company now only provides meter read data to these municipalities. In its projection of attrition period sewer billing revenues, the Company included an increased number of disconnection orders that it expects to receive from municipal sewer companies for non-payment. However, the Company included these revenues in the attrition period at the Company's proposed disconnection rate of $31.00 instead of the current disconnection rate of $15.50.[5] The CAPD's attrition period revenue calculation corrects this error.

Q12. DID THE CAPD ALSO INCLUDE AN ADJUSTMENT FOR DECLINING CUSTOMER USAGE IN THIS CASE?

A12. Yes.

Q13. PLEASE EXPLAIN THE CAPD'S METHODOLOGY FOR COMPUTING CUSTOMER USAGE.

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3 Company Exhibit REV-3-Revenue by Class-DJP, Schedule REV 3.1, Chattanooga-Residential.

4 TRA Docket 12-00042.

5 Company Exhibit, REV-1-Summary-DJP, Schedule REV-1.1, Page 1, Line 30 and also Company Exhibit REV-2-Other Revenue-DJP, Schedule REV-2.1, Workpaper 1, Page 2.

A13. We began by examining the Company's water sales per customer for residential, commercial and public authority customers over the last six years. We then used regression analysis to forecast customer usage to the midpoint of the attrition year based upon the actual observations of water sales per customer for the last six years.

Q14. WHAT DID YOUR ANALYIS OF CUSTOMER USAGE REVEAL?

A14. For the residential and commercial customers, our analysis showed a clear decline in usage per customer. As a result, we have reduced the test period residential customer usage by 76,136 CCF[6] and reduced the test period commercial customer usage by 26,457 CCF.[7] However, our analysis of usage for public authority customers revealed an increase in customer usage. As a result, we increased the test period public authority customer usage by 44,580 CCF.[8]

Q15. ARE THERE ANY OTHER REVENUE ADJUSTMENTS THAT SHOULD BE BROUGHT TO THE TRA'S ATTENTION?

A15. Yes. The Company currently provides water service to Fort Oglethorpe, Catoosa County, Signal Mountain, and Walden's Ridge at special contract rates. However, the Company has no contract in place with either Catoosa County or the Town of Signal Mountain and the contracts with for Fort Oglethorpe and Walden's Ridge are dated in 2003 and 2004.[9] As a result, we are unable to

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[6] CAPD Revenue Workpaper R-R-6.00.
[7] CAPD Revenue Workpaper R-C-6.00.
[8] CAPD Revenue Workpaper R-OPA-6.00.
[9] Company response to CAPD Data Request, Item 11.

determine any support for the Company's current billing rates for these customers. In addition, it appears that the Company has increased the rates during the test period to these customers without the approval of the TRA. The CAPD has requested supplemental information concerning its billing rates to special contract customers but has not received a response as of the date for filing testimony. Going forward, the Company has proposed to include the billing rates for these special contract customers in its tariff.[10] This change in tariff structure will eliminate the need for Special Contract altogether and makes the most sense from a rate administration viewpoint.

II. ATTRITION PERIOD RATE BASE

Q16 MR. NOVAK, PLEASE DESCRIBE THE MAJOR AREAS OF DIFFERENCE BETWEEN THE COMPANY'S AND CAPD'S CALCULATION OF RATE BASE.

A16. As shown on CAPD Exhibit, Schedule 3, the total difference between the Company and the CAPD's rate base calculation is approximately $13.6 million. The primary difference in rate base is due to the CAPD's exclusion of costs related to the Company's proposed Business Transformation. In addition, significant differences between the Company and CAPD's calculations for accumulated deferred federal income taxes and customer advances also result in major variances in the two rate base calculations.

[10] Company Proposed Tariff, Sheet No. 4-S2.

Q17. PLEASE BRIEFLY DISCUSS THE COMPANY'S PROPOSED BUSINESS TRANSFORMATION PROJECT.

A17 According to the Company, its proposed Business Transformation project will include Enterprise Resource Planning, Enterprise Asset Management and the Customer Information System.[11] Also, according to the Company, the total projected cost of the Business Transformation system is over $320 million, or 12% of consolidated revenues, with Tennessee-American's allocated share projected at $7.8 million.[12]

At $7.8 million, the cost for Tennessee-American's share of Business Transformation comes to just over $104 per customer. At an installed cost of $104 per customer, Business Transformation would be one of the most expensive non-revenue producing projects that the Company has ever undertaken. By comparison, the Company's complete cost to physically extend service to new customers is only $1,277 making Business Transformation an expensive addition for the Company's customers.[13]

Furthermore, these systems rarely come in at the budgeted amount and are often delayed. Also, in extreme cases, the implementation of these systems has resulted in the bankruptcy of the individual companies choosing them. I have included in Attachment WHN-2, a number of documents relating to the Company's Business Transformation proposal which I refer to in my testimony that follows.

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[11] Direct testimony of Company witness VerDouw, Page 27.
[12] Direct testimony of Company witness VerDouw, Page 37.
[13] Company response to the TRA's Minimum Filing Requirements, Item 24.

Q18. WHY HAS THE CAPD CHOSEN TO EXCLUDE BUSINESS TRANSFORMATION COSTS FROM RATE BASE?

A18. The CAPD feels that the Company has simply not done enough to justify this material expenditure. According to the Company, its existing systems are "antiquated" and at the end of their useful lives.[14] This appears to be the only justification for Business Transformation in the Company's case. However, these systems still appear to be working correctly and are currently getting the job done for the Company. Furthermore, just because the existing systems have already been fully depreciated and paid for by the Company's customers, does not mean that they are at the end of their useful lives.

In addition, the Company's expected benefits from the Business Transformation system are esoteric and obscure. The Company's benefit description includes items such as opportunities for "enhanced bill presentation" or "greater first contact resolution" but doesn't specifically go into why these abilities are currently needed. The CAPD believes that the TRA needs a firmer grasp of the customer benefits from Business Transformation before committing to its $7.8 million cost.

Finally, a significant number of companies that have attempted to implement the same SAP system platform that TAWC now proposes, have failed dramatically. In fact, the SAP system itself is notorious for problematic implementations and not delivering what was promised. These failures have resulted in several lawsuits against SAP[15] and have contributed to the bankruptcy of at least one

[14] Direct testimony of Company witness VerDouw, Page 29.
[15] Attachment WHN-2, Item 1.

company[16] and shareholder actions against management[17] in another. All of these failed implementations are similar in size and scope, when measured against revenues, to that of AWWC. Even SAP itself has admitted to substantial usability problems in its software.[18]

One would expect that a capital expenditure of the magnitude that the Company has proposed for Business Transformation would at least partially pay for itself by decreasing costs. TAWC initially identified cost savings and benefits when Business Transformation was first presented to its board, but has since said that any cost savings or benefits are too uncertain to quantify.[19] For these reasons, the CAPD has chosen to exclude the Company's proposed costs for Business Transformation from rate base.

Q19. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE COMPANY AND CAPD'S FORECAST OF ACCUMULATED DEFERRED FEDERAL INCOME TAXES.

A19. Accumulated Deferred Federal Income Taxes ("ADFIT") represent the difference between expenses that recognized for tax and book purposes with the largest portion related to accelerated depreciation for tax purposes. The Company's forecast calculation of ADFIT appears to have only included the test period amount while the CAPD's calculation included growth related to additional plant to be placed in service through the attrition year.

[16] Attachment WHN-2, Item 2.
[17] Attachment WHN-2, Item 3.
[18] Attachment WHN-2, Item 4.
[19] Attachment WHN-2, Item 5.

Q20. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE COMPANY AND CAPD'S FORECAST OF CUSTOMER ADVANCES.

A20. Customer Advances represent refundable non-investor supplied funds that the Company has used to finance a portion of its plant investment and should therefore be treated as a deduction in computing rate base. In computing Customer Advances, the Company neglected to include the portion of Customer Advances projected to be refunded during the attrition year. In addition, the CAPD included a two year average of Customer Advances in its calculation resulting in the remaining difference.

III. CLASS COST OF SERVICE STUDY

Q21. PLEASE BRIEFLY EXPLAIN THE PURPOSE OF THE ALLOCATION PROCESS IN THE COMPANY'S CLASS COST OF SERVICE STUDY.

A21. The purpose of any Class Cost of Service Study ("CCOSS") is to arrive at the cost of serving each customer class and present a systematic approach to allocating this cost (or total revenue requirement) to the different classes of customers. The CCOSS can then provide a measure of guidance for the TRA to consider how to adjust individual rates for each customer class to produce the total revenue requirement. In this case, the Company has developed a CCOSS using twenty-three (23) separate allocation factors.[20]

[20] Direct testimony and exhibits of Company witness Herbert, Schedule C.

Q22. DO YOU AGREE WITH THE COMPANY'S CCOSS METHODOLOGY IN THIS CASE?

A22. No. Many components of the 23 allocation factors used in the Company's CCOSS are based on judgment without any substantiation whatsoever.[21] In my opinion, it is unacceptable to use "judgment factors" for a CCOSS because the result is a study that cannot be independently verified or corroborated.

Q23. HOW DOES THE CAPD PROPOSE TO ALLOCATE ANY REVENUE DEFICIENCY TO EACH OF THE CUSTOMER CLASSES?

A23. The CAPD has traditionally proposed to increase service charges and volumetric rates in a manner so that each customer class receives the same approximate percentage increase. Incidentally, this methodology is identical to what the Company proposed in their last rate case.[22] The CAPD believes that an across-the-board increase to all customer classes most equitably spreads the burden of any increase in rates and is preferable to the Company's CCOSS results. The calculation of the CAPD's proposed rate design and resulting rates from it are shown on CAPD Exhibit, Schedules 16 and 17.

However, the CAPD does recognize that the Company and intervenors have presented material testimony and evidence relating to the impact on large water users and sale for resale customers from across-the-board rate design allocations.

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[21] Direct testimony of Company witness Herbert, Page 10. See also Company response to CAPD Data Request, Item 50.
[22] TRA Docket 10-00189.

The TRA may want to give appropriate weight to this evidence when setting rates in this docket.

IV. TAWC COST RECOVERY PROPOSALS

Q24. HAS TENNESSEE-AMERICAN WATER COMPANY PROPOSED ANY PARTICULAR PROGRAMS IN THIS RATE CASE WHERE IT SEEKS SPECIAL COST RECOVERY?

A24. Yes. The Company has proposed what it calls a Distribution System Infrastructure Charge ("DSIC") to recover its cost of infrastructure replacement between rate cases. In addition, the Company has proposed a Purchased Power and Chemicals Charge ("PPACC") tariff rider to recover any incremental changes to these expenses from the level set in the rate case. Finally, the Company has proposed a Pension Cost Tracker to defer and recover changes in pension expenses from the amounts recognized in the Company's rate case.

Q25. DO YOU AGREE WITH THE COMPANY'S PROPOSALS FOR THESE SPECIAL COST RECOVERY MECHANISMS?

A25. No, I do not. Each of these proposals is designed to minimize the Company's risk of operations without any corresponding concession to the Company's proposed return on equity. In addition, there is simply not enough demonstrated volatility within any of these categories to justify the cost tracking structure that the Company proposes. Finally, the implementation of such a tracking proposal in these categories would be unprecedented for any private utility in Tennessee. The

CAPD therefore asks the TRA to reject each of the Company's proposals for special cost recovery.

Q26. DOES THIS COMPLETE YOUR TESTIMONY?

A26. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available.

ATTACHMENT

5

BEFORE
THE TENNESSEE REGULATORY AUTHORITY

Petition of Piedmont Natural Gas Company, Inc. for an Adjustment to its Rates, Approval of Changes to its Rate Design, Amortization of Certain Deferred Assets, Approval of New Depreciation Rates, Approval of Revised Tariffs and Service Regulations, and Approval of a New Energy Efficiency Program and GTI Funding	)))))))))	Docket No. 11-00144

DIRECT TESTIMONY
of
WILLIAM H. NOVAK

ON BEHALF OF
THE CONSUMER ADVOCATE AND PROTECTION DIVISION
OF THE
TENNESSEE ATTORNEY GENERAL'S OFFICE

December 6, 2011

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ATTACHMENTS

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.[1]

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am a Certified Management Accountant, and am also licensed to practice as a Certified Public Accountant.

My work experience has centered on regulated utilities for over 25 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee. I also served for two years as the Vice President of Regulatory Compliance for Sequent Energy Management, a natural

[1] State of Tennessee, Registered Accounting Firm ID 3682.

gas trading and optimization entity in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am testifying on behalf of the Consumer Advocate & Protection Division ("CAPD" or "the Consumer Advocate") of the Tennessee Attorney General's Office.

Q4. HAVE YOU PRESENTED TESTIMONY IN ANY PREVIOUS PIEDMONT RATE CASES?

A4. Yes. I presented testimony in Dockets U-85-7355, U-87-7499, 89-10491, and 91-02636 concerning either Nashville Gas Company or Piedmont Natural Gas Company ("Piedmont" or "the Company") rate cases as well as other generic tariff and rulemaking dockets. In addition, I advised the TRA Directors in the Company's last rate case (Docket 03-00313) on issues where I did not present testimony.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A5. My testimony will support and address the CAPD's positions and concerns with respect to the Company's Petition. Specifically, I will address the following:

i. CAPD's proposed attrition period revenue and gas cost calculations;

ii. CAPD's position on Piedmont's proposed Cost of Service Study;

iii. CAPD's proposed rate design;

iv. CAPD's position on Piedmont's proposed cost recovery proposals for an Energy Efficiency Program and GTI Funding; and

v. CAPD's position on certain aspects of Piedmont's proposed tariff revisions.

Q6. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A6. I have reviewed the Company's Rate Case Application as filed on September 2, 2011, along with the testimony and exhibits presented with their filing. In addition, I have reviewed the Company's workpapers supporting their attrition period revenues and cost of service study. I have also reviewed the Company's responses to the relevant data requests submitted by the TRA as well the Company's responses to CAPD's discovery requests in these same areas.

I. ATTRITION PERIOD REVENUES & GAS COST

Q7. MR. NOVAK, PLEASE DESCRIBE THE MAJOR AREAS OF DIFFERENCE BETWEEN THE COMPANY'S AND CAPD'S CALCULATION OF ATTRITION PERIOD BILLING DETERMINANTS.

A7. The primary differences are due to different forecasts for normal weather, annualized customer usage and customer growth. As shown in detail on Attachment WHN-2, Schedule 1 and summarized below in Table 1, the CAPD first began with the Company's test period sales and transportation volumes of

296,047,022 therms, 1,988,976 bills and 277,186 billing demand units.[2] We then adjusted for normal weather, annualized customer usage and customer growth to arrive at attrition billing determinants of 288,167,934 therms, 2,021,045 bills and 219,672 billing demand units.

Table 1 – Summary of CAPD Attrition Period Billing Determinants				
	Test Period	Weather Adjustment	Customer Growth	Attrition Period
Bills	1,988,976	0	32,069	2,021,045
Billing Demand	277,186	0	-57,514	219,672
Therms	296,047,022	-5,269,571	-2,609,517	288,167,934

I have also included a detailed comparison with the Company's attrition period billing determinants on Attachment WHN-2, Schedule 2. This comparison is summarized below on Table 2.

Table 2 – Comparison of Company and CAPD Attrition Period Billing Determinants			
	Company	CAPD	Difference
Bills	2,008,767	2,021,045	12,278
Billing Demand	219,672	219,672	0
Therms	287,155,030	288,167,934	1,012,904

Q8. WHY IS THE CAPD'S WEATHER ADJUSTMENT DIFFERENT FROM THE COMPANY'S?

A8. The CAPD's weather adjustment for the residential and commercial customer classes is different from the Company's for two reasons. First, there were errors in the Company's calculation of normal weather and test period weather.[3] In addition, the Company chose to separately weather normalize the residential and

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[2] Billing Demand Units refers to peak day capacity subscribed to by the Company's firm industrial customers on Rate Schedules 303 and 313.

[3] The Company incorrectly calculated normal cycle heating degree days for March as 534 instead of 518. In addition, the Company also incorrectly calculated the cycle heating degree days for May 2011 as 115 instead of 113.

commercial standard and value designations that it now proposes to eliminate whereas the CAPD consolidated these tariff designations in its weather normalization calculation.

Furthermore, with the elimination of the value and standard designations the CAPD believes that the SGS and MGS tariffs[4] need to be combined for weather normalization purposes as they were prior to the Company's 2003 rate case. The CAPD therefore performed separate weather normalization studies for the entire residential and commercial customer classes.

The combination of these two errors results in the entire difference between the Company and CAPD's weather normalization adjustments. In addition, I have also prepared a weather normalization factor summary that is included on Attachment WHN-3 for Weather Normalization Adjustment ("WNA") tracking purposes that implements the CAPD's proposals to consolidate the residential and commercial tariffs.

Q9. HOW HAS THE CAPD ADJUSTED THE ATTRITION PERIOD BILLING DETERMINANTS FOR EXISTING CUSTOMER USAGE?

A9. The CAPD adjusted industrial customer usage by individually analyzing the sales volumes of the Company's 25 largest customers. These 25 customers represented over 72% of the Company's test period volumes to the industrial class. Where we felt that it was necessary, such as a large swing in gas usage or a material tariff

[4] Small General Service and Medium General Service tariffs that comprise the Commercial customer class.

transfer, we adjusted the test period usage to take these changes into account. We then compared our own adjustments with those proposed by the Company. For the most part, we felt that the Company had properly adjusted for any test period anomalies and tariff transfers within the industrial customer group. However, we did find evidence where a large customer's usage was curtailed due to flooding during the test period that the Company didn't include in their filing.[5] As a result, we have made an adjustment of 818,070 therms to properly reflect this customer's going level consumption in the attrition period.[6]

Q10. HOW WERE SALES VOLUMES FOR ADDED CUSTOMERS COMPUTED?

A10. A historical average of added customers to normal plant additions was first calculated. This average was then applied to the CAPD's forecast of attrition period normal plant additions giving residential and commercial "customers to be added" during the attrition year. More simply stated though, the CAPD has increased the number of residential and commercial customers based upon an average historical ratio of customer additions to normal plant additions. These forecasted customer additions were then multiplied by an average usage volume per customer giving additional attrition period sales volumes for the residential and commercial rate classes.

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[5] Metro Water Services, Account #7000176578004.
[6] CAPD Workpaper R-7-I-2.02.

While other witnesses will testify more fully on the CAPD's forecast of plant in service, I would like to point out that if the TRA should decide to adjust the CAPD's forecasted plant in service, then a corresponding adjustment should also be made to revenues.

Q11. HOW WERE THE ATTRITION PERIOD BILLING DETERMINANTS TRANSLATED INTO REVENUES?

A11. The attrition period billing determinants as shown on Attachment WHN-2 were multiplied by the existing base tariff rates and the PGA rate based upon the Company's demand and commodity gas costs at April 1, 2011. This gives total attrition period gas sales and transportation revenues of $94,603,962 as shown on Attachment WHN-4 and summarized below in Table 3.

Table 3 – Comparison of Company and CAPD Attrition Period Gross Margin under Current Rates

	Company	CAPD	Difference
Residential	$54,662,151	$55,025,059	$362,908
Commercial	28,683,304	28,803,370	120,066
Industrial	8,315,092	8,428,238	113,146
Special Contract	624,617	434,249	-190,368
Sales for Resale	28,481	28,481	0
Other Revenue	2,005,089	1,884,565	-120,524
Total	**$94,318,734**	**$94,603,962**	**$285,228**

Q12. HOW DID THE CAPD COMPUTE OTHER REVENUES?

A12. Other revenues primarily consist of forfeited discounts, reconnection charges, bad check charges and rental income from utility property. To compute forfeited discounts, the CAPD took the historical ratio of forfeited discounts to residential and commercial revenues, since these are ordinarily the customers who generate forfeited discounts. This ratio was then multiplied by the attrition period residential and commercial revenues. To compute the other items for this category, I analyzed the test period amounts and adjusted for growth where appropriate. This produced $1,884,565 in Other Revenues as shown on Attachment WHN-4.

Q13. HOW WAS THE CAPD'S COST OF GAS COMPUTED?

A13. We began with the attrition period throughput volumes and billing demand discussed above. These determinants were then priced out at the April 1, 2010 PGA rates. This produced $94,601,622 in gas cost as shown on Attachment WHN-5.

II. COST OF SERVICE STUDY

Q14. PLEASE BRIEFLY EXPLAIN THE PURPOSE OF THE ALLOCATION PROCESS IN THE COMPANY'S COST OF SERVICE STUDY.

A14. The purpose of any Cost of Service Study ("COSS") is to arrive at the cost of serving each customer class and present a systematic approach to allocating this cost (or total revenue requirement) to the different classes of customers. The COSS then provides a measure of guidance for the TRA to consider how to best adjust individual rates for each customer class to produce the total revenue requirement.

Q15. HAVE YOU REVIEWED THE COMPANY'S PROPOSED COST OF SERVICE STUDY IN THIS CASE?

A15. Yes. The Company has developed a COSS that first classifies each element of rate base and income into three categories for demand costs, customer costs and commodity costs. The Company then allocates these classified costs using 40 separate allocation factors.[7] The result of the Company's COSS is to allocate 98% of the operating expenses to residential and commercial customers and allocating the remaining 2% to industrial customers.[8]

Q16. DO YOU AGREE WITH THE COMPANY'S COSS METHODOLOGY IN THIS CASE?

A16. No. There are mathematical errors in the Company's study that need to be corrected.[9] These errors cascade down through the Company's COSS, resulting in errors to other allocation factors that depend upon them.

In addition, the assignment of 40 individual allocation factors to each element of the Company's cost of service is inherently judgmental, and the Company has not introduced any evidence to fully explain their rationale for each individual allocation assignment. For example, the Company has allocated a significant portion of their costs based upon peak day consumption, meaning that almost all of these costs will be allocated to residential and commercial customers without

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[7] Direct testimony and exhibits of Company witness Yardley.

[8] Company Exhibit DPY-5, Page 8.

[9] The Company incorrectly calculates the Plant in Service classification by omitting $557,644 in commodity costs. In addition, the Company incorrectly calculates the distribution services classification by omitting $25,937,975 in meter costs.

any discussion or evidence as to why such an allocation is appropriate. I could easily justify allocating many of these same costs based upon the total throughput of each customer class which would then allocate a majority of the costs to industrial customers. Since the Company has not provided any rationale for its individual allocation choices it is impossible to determine their rationale for cost allocation.

Finally, other factors beyond just the cost of service need to also be considered in allocating costs. These other factors include value of service, product marketability, encouragement of efficient use of facilities, broad availability of service functions, and a fair distribution of charges among users. Since it is impossible to properly consider each of these other factors, it follows that no mechanical or mathematical formula can ever be applied to the cost of service that would translate it directly into rates.

Q17. HOW DOES THE CONSUMER ADVOCATE PROPOSE THAT THE TRA ALLOCATE THE COMPANY'S REVENUE REQUIREMENTS TO EACH CUSTOMER CLASS?

A17. The CAPD recommends that its proposed revenue deficiency of $9,863,394 be allocated evenly across-the-board to all customer classes, including special contract customers, based upon the ratio of each customer class' attrition period margin to total attrition period margin. The CAPD's complete revenue deficiency allocation is presented on Exhibit WHN-6 and summarized below on Table 4.

Table 4 – Comparison of Company and CAPD Attrition Period Revenue Deficiency Allocation			
	Current Margin	**CAPD Allocation**	**Company Allocation**
Residential	$55,025,058	59.34%	65.95%
Commercial	28,803,371	31.07%	28.17%
Industrial	8,428,238	9.09%	5.85%
Special Contract & Sale for Resale	462,730	0.50%	0.03%
Other Revenue	1,884,565	- N/A -	- N/A -
Total	**$94,603,962**	**100.00%**	**100.00%**

To summarize the results of Table 4, the CAPD would allocate 59.34% of any revenue increase to residential customers based upon an across-the-board distribution of attrition period margin under current rates. Alternatively, the Company would allocate 65.95% of any revenue increase to residential customers based upon their COSS. The CAPD believes that an across-the-board increase to all customer classes more equitably spreads the burden of any increase in rates and is preferable to the Company's COSS results.

III. RATE DESIGN

Q18. HAVE YOU REVIEWED THE COMPANY'S PROPOSED RATE DESIGN?

A18. Yes. The Company's proposed rate design realigns "…rates within each [customer] class to recover a greater proportion of fixed revenue requirements through fixed charges."[10] Stated more simply, the Company is proposing to reduce its existing base rate commodity charge for all tariffs while increasing the fixed monthly customer charges to make up for the difference. The primary

[10] Direct testimony of Company witness Yardley, page 15, lines 15 – 16.

driver behind this proposal is the continuing decline in sales volumes for new customers. The result of the Company's proposal is a substantial increase of as much as 120% in monthly customer charges.

Q19. DO YOU AGREE WITH THE COMPANY'S RATE DESIGN PROPOSAL?

A19. No. While I do agree that the Company has experienced declines in customer usage due to efficiency and technology gains in gas appliances, I believe that the changes proposed by the Company are too radical to implement in a single rate case.

Q20. WHAT RATE DESIGN DOES THE CAPD PROPOSE?

A20. The CAPD recognizes that the decline in customer usage has impaired the gas utilities ability to earn a fair rate of return. For that reason, we are proposing a <u>gradual</u> shift towards placing more margin on customer charges than through volumetric charges. However, we believe that this revenue shift must occur gradually rather than through an immediate change to a new rate structure. We are therefore proposing that the entire revenue deficiency in this case be recovered through increased customer charges only. In other words, we are proposing that the existing base rate commodity charges remain at their current levels. We feel that this proposal shifts more of the Company's revenue recovery towards fixed charges but avoids a radical change of existing commodity rates. The CAPD's complete rate design is contained on Exhibit WHN-6 and summarized below on Table 5.

Table 5 – CAPD Proposed Rate Design			
Tariff	**Current Rates**	**Company Proposed**	**CAPD Proposed**
Residential			
Summer Bills per Month	$10.00	$17.00	$12.84
Winter Bills per Month	13.00	22.00	16.69
Summer Usage/Therm	0.2700	0.2214	0.2700
Winter Usage/Therm	0.3200	0.2714	0.3200
Commercial			
Small Customer Charges[11]	$29.00	$40.00	$41.31
Medium Customers Charges[12]	75.00	125.00	197.22
Small Summer Usage/Therm	0.3030	0.3277	0.3030
Small Winter Usage/Therm	0.3540	0.3787	0.3540
Medium Summer Usage/Therm	0.3030	0.3398	0.3030
Medium Winter Usage/Therm	0.3540	0.3908	0.3540
Industrial			
Customer Charges per Month	$300.00	$450.00	$710.97
Billing Demand Charges/Therm	0.80	1.00	8.00
Usage – Step 1/Therm	0.09742	0.09948	0.09742
Usage – Step 2/Therm	0.08953	0.09159	0.08953
Usage – Step 3/Therm	0.06450	0.06656	0.06450
Usage – Step 4/Therm	0.02764	0.02970	0.02764
Special Contract	$434,249	$434,249	$480,071
Sales for Resale			
Customer Charges per Month	$0.00	$0.00	$96.95
Billing Demand Charges/Therm	0.80	1.00	0.80
Usage/Therm	0.09000	0.09870	0.09

IV. COST RECOVERY PROPOSALS

Q21. HAS PIEDMONT PROPOSED ANY PARTICULAR PROGRAMS IN THIS RATE CASE WHERE IT SEEKS COST RECOVERY?

11 Small usage customers are those whose average consumption is less than 200 therms per day.

12 Medium usage customers are those whose average consumption is greater than or equal to 200 therms per day.

A21. Yes. The Company has proposed what it calls an "Energy Efficiency Program" wherein it would spend $500,000 for educational activities in public schools to promote energy efficiency. The Company has also proposed a $150,000 contribution to the Gas Technology Institute ("GTI") to fund research and development activities. The Company is then asking to recover the $650,000 total cost of both programs through increased rates.

Q22. DOES THE CAPD SUPPORT THE COMPANY'S PROPOSED COST RECOVERY FOR THESE PROGRAMS?

A22. No. The CAPD is opposed to cost recovery for both of the Company's proposed programs. Both of these programs would result in an involuntary tax on gas consumers for funding since neither program is necessary in order to provide utility service. Furthermore, in the case of the Company's proposed "Energy Efficiency Program" there has been no evidence presented that Nashville area schools would allow a private entity to make such a presentation to its students. Finally, the program violates the state's conservation policy on "cost effective, measurable and verifiable savings"[13] since it requires all of the Company's 170,000 customers to pay for the benefits received by as few as 6,800 customers[14].

In the case of GTI funding, the benefits are illusory at best since any successful research would ultimately be marketed to manufacturers in the distant future. The

[13] Section 53 of Public Chapter 531.
[14] Testimony of Company witness Powers, Page 15.

CAPD therefore asks the TRA to reject both of the Company's proposals for cost recovery.

V. TARIFF CHANGES

Q23. MR. NOVAK, HAVE YOU REVIEWED THE TARIFF CHANGES PROPOSED BY THE COMPANY?

A23. Yes. In this case, the Company has proposed the following rate changes to its existing tariff:[15]

- The elimination of the standard/value designations for residential, small general service and medium general service tariffs;
- The elimination of step rates of 20,000 therms/month and 50,000 therms/month respectively for small and medium general service tariffs;
- A two month expansion of the WNA period from November – March to October – April;
- The establishment of a natural gas vehicle rate schedule;
- An update to the weighted average pipeline percentages included in rate schedules 307 and 313; and
- A proposal to retain the current allocation of fixed gas costs by rate class.

[15] Other non-rate changes to the Company's tariff are discussed by other CAPD witnesses.

Q24. What is the CAPD's position with respect to the Company's proposal to remove the standard/value designations for residential, small general service and medium general service tariffs?

A24. These designations were implemented in the Company's last rate case in 2003. However, from the customer's point of view, the designations were meaningless since the rates were the same for both the standard and the value designations. Removing these designations probably makes it easier for these customers to understand their bill. Therefore, the CAPD supports this change.

Q25. What is the CAPD's position with respect to the Company's proposal for eliminating the step rates of 20,000 therms/month and 50,000 therms/month respectively for small and medium general service tariffs?

A25. These step rates were also implemented in the Company's last rate case in 2003. Again however, the steps were meaningless from the customer's point of view since the rates were identical for consumption above and below the step. Removing these steps probably makes it easier for these customers to understand their bill. Therefore, the CAPD supports this change.

Q26. What is the CAPD's position with respect to the Company's proposal to implement a two month expansion of the WNA period?

A26. The CAPD is opposed to the Company's proposal to change the WNA recovery period. Since both the Company and the CAPD are now advocating a shift in revenue recovery towards customer charges and away from commodity charges, it would appear ill-timed to now implement a change in the WNA recovery period. In addition, since the WNA only addresses commodity charges, this change would impact a smaller portion of the Company's total revenues. The CAPD therefore proposes that the existing WNA period of November – March remain in effect.

Q27. What is the CAPD's position with respect to the Company's proposal to implement a natural gas vehicle tariff?

A27. The Company has proposed a new Rate Schedule 342 for Natural Gas Vehicle Fuel. The Company has also proposed a monthly customer charge of $40 and a consumption charge of $0.23109 per therm. The CAPD believes that the prospects for the natural gas fuel market are good and that this customer group may eventually develop and contribute to the recovery of the Company's common costs. The CAPD therefore supports the Company's initial proposal for this rate schedule until the next rate case.

Q28. What is the CAPD's position with respect to the Company's update to the weighted average pipeline percentages included in rate schedules 307 and 313?

A28. Rate Schedule 307 (Balancing, Cash-Out and Agency Authorization) and Rate Schedule 313 (Firm Transportation Service) both contain identical provisions that reflect the weighted average ratio of winter capacity from delivering pipelines. These percentages remain in effect until the Company's next rate case. The current and Company proposed values for these percentages are shown below in Table 6.

Table 6 – Pipeline Percentages		
Pipeline	**Current**	**Proposed**
TEXAS (SOUTH/EAST), Tenn Zone 1 Zone 0: South	28.36%	30.28%
GULF COAST, Tenn 500 So La Z1 Louisiana	65.32%	38.06%
GULF COAST, Tenn 800 So La Z1	6.32%	31.66%
Total	**100.00%**	**100.00%**

The CAPD has reviewed the Company's proposed calculations of the test period pipeline percentages and supports their inclusion in the tariff for Rate Schedules 307 and 313.

Q29. What is the CAPD's position with respect to the Company's position to retain the current allocation of fixed gas costs by rate class?

A29. The CAPD is opposed to the Company's position on this issue. In the Company's last rate case, the TRA approved a new mechanism whereby the Company was allowed to recover different amounts of pipeline demand charges from different customer classes. A copy of these fixed gas costs are included in Company Exhibits DRC-4 and PKP-1. Currently, no other gas utility has such a mechanism that allows for variable fixed gas rate recovery from different customer classes. Instead, these fixed gas costs are recovered through the PGA process and typically included in the commodity PGA for most customers.[16]

[16] Industrial Rate 303 and 313 customers have unique demand billing attributes assigned to them.

The sole purpose for the implementation of variable demand charges in the last rate case was to place a higher charge for demand recovery from "standard rate" customers than from "value rate" customers. In fact, except for the demand recovery rates, the current value/standard designations for residential and commercial customers are identical. Now, with the elimination of the standard/value designations, the use of variable demand charges serves no purpose. The CAPD therefore recommends that all variable demand charges be eliminated and that the Company revert to filing for its fixed cost recovery through the PGA.

Q30. DOES THIS COMPLETE YOUR TESTIMONY?

A30. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available.

IN THE TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE

IN RE:	)	
	)	
Petition of Piedmont Natural Gas	)	
Company, Inc. for an Adjustment to its	)	
Rates, Approval of Changes to its Rate	)	Docket No. 11-00144
Design, Amortization of Certain Deferred	)	
Assets, Approval of New Depreciation	)	
Rates, Approval of Revised Tariffs and	)	
Service Regulations, and Approval of a	)	
New Energy Efficiency Program and GTI	)	
Funding	)	

AFFIDAVIT

I, William H. Novak, CPA, on behalf of 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.

WILLIAM H. NOVAK

Sworn to and subscribed before me
this 28 **day of** NOV **, 2011.**

NOTARY PUBLIC

My commission expires: 2-24-15

TAMMY L. JONES
Notary Public
STATE OF TEXAS
My Comm. Exp. 02-24-15

ATTACHMENT WHN-1

William H. Novak Vitae

William H. Novak
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The Woodlands, TX 77381

Phone: 713-298-1760
Email: halnovak@whnconsulting.com

Areas of Specialization

Over twenty-five years of experience in regulatory affairs and forecasting of financial information in the rate setting process for electric, gas, water and wastewater utilities. Presented testimony and analysis for state commissions on regulatory issues in four states and has presented testimony before the FERC on electric issues.

Relevant Experience

WHN Consulting – September 2004 to Present
In 2004, established WHN Consulting to provide utility consulting and expert testimony for energy and water utilities. Complete needs consultant to provide the regulatory and financial expertise that enabled a number of small gas and water utilities to obtain their Certificate of Public Convenience and Necessity (CCN) that included forecasting the utility investment and income. Also provided the complete analysis and testimony for utility rate cases including revenues, operating expenses, taxes, rate base, rate of return and rate design for utilities in Tennessee. Assisted American Water Works Company in preparing rate cases in Ohio and Iowa. Provided commercial and industrial tariff analysis and testimony for an industrial intervenor group in a large gas utility rate case. Industry spokesman for water utilities dealing with utility commission rulemaking. Consultant for the North Carolina and Illinois Public Utility Commissions in carrying out their oversight functions of Duke Energy and Peoples Gas Light and Coke Company through focused management audits. Also provide continual utility accounting services and preparation of utility commission annual reports for water and gas utilities.

Sequent Energy Management – February 2001 to July 2003
Vice-President of Regulatory Compliance for approximately two years with Sequent Energy Management, a gas trading and optimization affiliate of AGL Resources. In that capacity, directed the duties of the regulatory compliance department, and reviewed and analyzed all regulatory filings and controls to ensure compliance with federal and state regulatory guidelines. Engaged and oversaw the work of a number of regulatory consultants and attorneys in various states where Sequent has operations. Identified asset management opportunities and regulatory issues for Sequent in various states. Presented regulatory proposals and testimony to eliminate wholesale gas rate fluctuations through hedging of all wholesale gas purchases for utilities. Also prepared testimony to allow gas marketers to compete with utilities for the transportation of wholesale gas to industrial users.

Atlanta Gas Light Company – April 1999 to February 2001

Director of Rates and Regulatory Analysis for approximately two years with AGL Resources, a public utility holding company serving approximately 1.9 million customers in Georgia, Tennessee, and Virginia. In that capacity, was instrumental in leading Atlanta Gas Light Company through the most complete and comprehensive gas deregulation process in the country that involved terminating the utility's traditional gas recovery mechanism and instead allowing all 1.5 million AGL Resources customers in Georgia to choose their own gas marketer. Also responsible for all gas deregulation filings, as well as preparing and defending gas cost recovery and rate filings. Initiated a weather normalization adjustment in Virginia to track adjustments to company's revenues based on departures from normal weather. Analyzed the regulatory impacts of potential acquisition targets.

Tennessee Regulatory Authority – Aug. 1982 to Apr 1999; Jul 2003 to Sep 2004

Employed by the Tennessee Regulatory Authority (formerly the Tennessee Public Service Commission) for approximately 19 years, culminating as Chief of the Energy and Water Division. Responsible for directing the division's compliance and rate setting process for all gas, electric, and water utilities. Either presented analysis and testimony or advised the Commissioners/Directors on policy setting issues, including utility rate cases, electric and gas deregulation, gas cost recovery, weather normalization recovery, and various accounting related issues. Responsible for leading and supervising the purchased gas adjustment (PGA) and gas cost recovery calculation for all gas utilities. Responsible for overseeing the work of all energy and water consultants hired by the TRA for management audits of gas, electric and water utilities. Implemented a weather normalization process for water utilities that was adopted by the Commission and adopted by American Water Works Company in regulatory proceedings outside of Tennessee.

Education

B.A, Accounting, Middle Tennessee State University, 1981
MBA, Middle Tennessee State University, 1997

Professional

Certified Public Accountant (CPA), Tennessee Certificate # 7388
Certified Management Accountant (CMA), Certificate # 7880
Former Vice-Chairman of National Association of Regulatory Utility Commission's Subcommittee on Natural Gas

ATTACHMENT WHN-2

CAPD Pro Forma Billing Determinants

Piedmont-Nashville
CAPD Pro Forma Billing Determinants

Attachment WHN-2
Schedule 1

Line No.	Tariff	Test Period	Weather Adjustment	Customer Growth	Attrition Period
	Residential				
1	Bills - Winter	749,069		10,972	760,041
2	Bills - Summer	1,036,462		19,388	1,055,850
3	**Total Bills**	**1,785,531**		**30,360**	**1,815,891**
4	Therms - Winter	90,323,919	-5,078,068	5,443,127	90,688,978
5	Therms - Summer	22,684,308	1,511,077	-3,582,230	20,613,155
6	**Total Volumes**	**113,008,227**	**-3,566,991**	**1,860,897**	**111,302,133**
	Commercial (SGS and MGS):				
7	Bills - Winter	84,677		596	85,273
8	Bills - Summer	116,550		1,124	117,674
9	**Total Bills**	**201,227**		**1,720**	**202,947**
10	Therms - Winter	48,785,794	-2,413,430	2,580,102	48,952,466
11	Therms - Summer	19,001,521	710,850	-2,015,236	17,697,135
12	**Total Volumes**	**67,787,315**	**-1,702,580**	**564,866**	**66,649,601**
	Industrial Sales & Transportation:				
13	Bills	2,162		2	2,164
14	Demand	277,186		-57,514	219,672
15	First 15,000 Therms	23,059,400		132,180	23,191,580
16	Next 25,000 Therms	16,334,970		250,000	16,584,970
17	Next 50,000 Therms	12,550,840		578,340	13,129,180
18	Over 90,000 Therms	40,188,720		11,571,500	51,760,220
19	**Total Volumes**	**92,133,930**		**12,532,020**	**104,665,950**
	Special Contract:				
20	Bills	25		-13	12
21	Therms	23,014,430		-17,567,300	5,447,130
	Sale for Resale:				
22	Bills	31		0	31
23	Demand	16,800		-14,400	2,400
24	Therms	103,120		0	103,120
25	**Total Bills**	**1,988,976**	**0**	**32,069**	**2,021,045**
26	**Total Demand**	**277,186**	**0**	**-57,514**	**219,672**
27	**Total Therms**	**296,047,022**	**-5,269,571**	**-2,609,517**	**288,167,934**

SOURCE: CAPD Revenue Workpaper R-13.01.

Piedmont-Nashville
Comparison of Company and CAPD Pro Forma Billing Determinants

Attachment WHN-2
Schedule 2

Line No.	Consumer Advocate	Company A/	CAPD B/	Difference
	Residential			
1	Bills - Winter	758,266	760,041	1,775
2	Bills - Summer	1,047,658	1,055,850	8,192
3	**Total Bills**	**1,805,924**	**1,815,891**	**9,967**
4	Therms - Winter	88,586,380	90,688,978	2,102,598
5	Therms - Summer	22,149,900	20,613,155	-1,536,745
6	**Total Volumes**	**110,736,280**	**111,302,133**	**565,853**
	Commercial (SGS and MGS):			
7	Bills - Winter	84,670	85,273	603
8	Bills - Summer	115,954	117,674	1,720
9	**Total Bills**	**200,624**	**202,947**	**2,323**
10	Therms - Winter	47,577,320	48,952,466	1,375,146
11	Therms - Summer	19,142,250	17,697,135	-1,445,115
12	**Total Volumes**	**66,719,570**	**66,649,601**	**-69,969**
	Industrial Sales & Transportation:			
13	Bills	2,152	2,164	12
14	Demand	219,672	219,672	0
15	First 15,000 Therms	23,194,400	23,191,580	-2,820
16	Next 25,000 Therms	16,559,970	16,584,970	25,000
17	Next 50,000 Therms	13,000,840	13,129,180	128,340
18	Over 90,000 Therms	48,167,520	51,760,220	3,592,700
19	**Total Volumes**	**100,922,730**	**104,665,950**	**3,743,220**
	Special Contract:			
20	Bills	36	12	-24
21	Therms	8,673,330	5,447,130	-3,226,200
	Sale for Resale:			
22	Bills	31	31	0
23	Demand	2,400	2,400	0
24	Therms	103,120	103,120	0
25	**Total Bills**	**2,008,767**	**2,021,045**	**12,278**
26	**Total Demand**	**219,672**	**219,672**	**0**
27	**Total Therms**	**287,155,030**	**288,167,934**	**1,012,904**

A/ Company Exhibit DRC-1.
B/ CAPD Attachment WHN-2, Schedule 1.

ATTACHMENT WHN-3

WNA Factors

Piedmont-Nashville
Summary of WNA Factors

Attachment WHN-3
Schedule 1

Tariff	"R" Value ($/Therm)	Heat Factor (Therms/DDD)	Base Factor (Therms/Mo.)
Residential	TBD	0.17945	7.91318
Commercial (SGS & MGS)	TBD	0.74873	104.85079

Piedmont-Residential
Cycle Weather Normalization
Nashville Heating Degree Days

Attachment WHN-3
Schedule 2

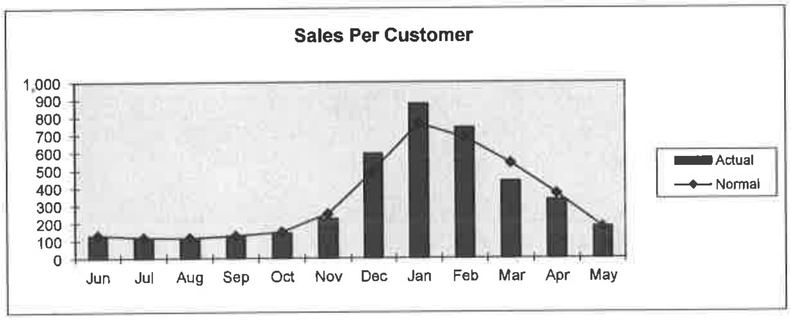
For the 12 Months Ended May 31, 2011

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	ACTUAL WEATHER	NORMAL WEATHER
June	1,986,500	147,976	13.4245	10	16
July	1,603,102	147,825	10.8446	0	0
August	1,514,414	147,449	10.2708	0	0
September	1,613,034	146,860	10.9835	0	1
October	2,222,777	146,626	15.1595	69	77
November	5,296,044	147,737	35.8478	274	311
December	17,168,174	149,341	114.9595	715	579
January	29,307,299	150,511	194.7187	949	798
February	24,595,687	150,767	163.1371	881	806
March	13,956,715	150,713	92.6046	381	518
April	9,923,668	150,258	66.0442	278	324
May	3,820,813	149,468	25.5627	113	108
TOTAL	**113,008,227**	**1,785,531**	**753.5574**	**3,670**	**3,538**

MONTH	WEATHER DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
June	5.9400	1.0660	14.4905	2,144,242	157,742
July	0.0600	0.0108	10.8554	1,604,699	1,597
August	0.1000	0.0179	10.2887	1,517,053	2,639
September	0.7200	0.1292	11.1127	1,632,008	18,974
October	8.1200	1.4572	16.6167	2,436,440	213,663
November	37.0700	6.6524	42.5002	6,278,850	982,806
December	-136.2800	-24.4561	90.5034	13,515,876	-3,652,298
January	-151.0900	-27.1138	167.6049	25,226,374	-4,080,925
February	-75.3900	-13.5291	149.6080	22,555,945	-2,039,742
March	137.2500	24.6302	117.2348	17,668,806	3,712,091
April	46.1500	8.2818	74.3260	11,168,075	1,244,407
May	-4.7700	-0.8560	24.7067	3,692,868	-127,945
TOTAL	**-132.1200**	**-23.7095**	**729.8479**	**109,441,236**	**-3,566,991**

Regression Output:

Constant	7.91317500
Std Err of Y Est	12.60424070
R Squared	0.96550403
X Coefficient	0.17945485
Std Err of Coef.	0.01072661



Piedmont-Commercial
Cycle Weather Normalization
Nashville Heating Degree Days

Attachment WHN-3
Schedule 3

For the 12 Months Ended May 31, 2011

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	ACTUAL WEATHER	NORMAL WEATHER
June	2,109,703	16,731	126.0955	10	16
July	1,935,453	16,655	116.2085	0	0
August	1,895,701	16,581	114.3297	0	0
September	2,084,668	16,448	126.7429	0	1
October	2,343,194	16,390	142.9649	69	77
November	3,678,624	16,535	222.4750	274	311
December	10,022,339	16,902	592.9676	715	579
January	14,973,464	17,093	875.9998	949	798
February	12,675,291	17,104	741.0717	881	806
March	7,436,076	17,043	436.3126	381	518
April	5,626,926	16,956	331.8546	278	324
May	3,005,876	16,789	179.0384	113	108
TOTAL	**67,787,315**	**201,227**	**4,006.0612**	**3,670**	**3,538**

MONTH	WEATHER DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
June	5.9400	4.4475	130.5430	2,184,114	74,411
July	0.0600	0.0449	116.2534	1,936,201	748
August	0.1000	0.0749	114.4046	1,896,943	1,242
September	0.7200	0.5391	127.2820	2,093,535	8,867
October	8.1200	6.0797	149.0446	2,442,840	99,646
November	37.0700	27.7555	250.2305	4,137,561	458,937
December	-136.2800	-102.0374	490.9302	8,297,703	-1,724,636
January	-151.0900	-113.1261	762.8737	13,039,800	-1,933,664
February	-75.3900	-56.4470	684.6247	11,709,822	-965,469
March	137.2500	102.7637	539.0763	9,187,478	1,751,402
April	46.1500	34.5540	366.4086	6,212,824	585,898
May	-4.7700	-3.5715	175.4669	2,945,914	-59,962
TOTAL	**-132.1200**	**-98.9227**	**3,907.1385**	**66,084,735**	**-1,702,580**

Regression Output:

Constant	104.85079190
Std Err of Y Est	42.16793515
R Squared	0.97754372
X Coefficient	0.74873344
Std Err of Coef.	0.03588624

Pledmont-Nashville
Nashville 30 Year Daily Normal Heating Degree Days

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	25.57	22.67	19.40	11.23	2.77	0.30	0.00	0.00	0.00	2.33	7.67	20.77
2	24.30	22.67	17.57	8.73	2.63	0.13	0.00	0.00	0.00	2.77	9.80	21.10
3	24.20	24.20	19.03	8.47	4.27	0.13	0.00	0.00	0.00	3.20	11.60	20.00
4	24.43	26.30	16.40	10.00	4.47	0.13	0.00	0.00	0.00	2.73	12.10	21.37
5	25.93	27.10	16.70	11.03	2.97	0.07	0.00	0.00	0.03	3.07	12.70	23.37
6	24.60	26.67	16.77	10.70	2.27	0.10	0.00	0.00	0.13	3.50	14.80	24.47
7	25.73	26.47	17.13	9.33	1.73	0.10	0.00	0.00	0.03	4.77	13.43	23.63
8	27.50	25.47	16.33	8.37	1.87	0.00	0.00	0.00	0.00	4.33	12.70	21.77
9	26.37	25.30	17.53	10.13	1.63	0.00	0.00	0.00	0.00	3.67	11.50	21.50
10	26.77	25.30	18.87	9.03	1.73	0.07	0.00	0.00	0.00	3.73	13.27	22.53
11	28.20	24.33	17.17	6.40	1.47	0.00	0.00	0.00	0.00	4.33	13.80	22.60
12	25.37	25.50	15.63	6.47	1.20	0.03	0.00	0.00	0.00	4.27	15.60	23.63
13	25.73	24.70	14.67	6.63	1.70	0.17	0.00	0.10	0.10	4.43	15.40	23.17
14	27.57	21.77	15.03	5.50	1.63	0.00	0.00	0.00	0.23	5.33	14.50	22.40
15	28.57	21.57	13.63	7.10	1.70	0.00	0.00	0.00	0.10	4.93	14.67	22.30
16	28.30	21.63	13.93	7.47	2.20	0.00	0.00	0.00	0.33	5.87	15.97	23.80
17	27.90	22.50	12.77	7.50	1.77	0.00	0.00	0.00	0.47	5.77	16.83	23.30
18	28.43	21.13	11.53	6.03	1.57	0.00	0.00	0.00	0.33	5.80	15.37	25.20
19	29.43	20.53	12.63	4.93	1.33	0.00	0.00	0.00	0.60	7.50	12.83	26.23
20	29.30	17.83	12.57	4.60	1.17	0.00	0.00	0.00	0.53	7.73	14.47	26.80
21	29.07	16.47	14.97	5.13	1.30	0.03	0.00	0.00	1.27	6.17	16.77	25.30
22	26.70	19.50	14.70	4.53	1.20	0.03	0.00	0.00	1.53	6.70	17.57	24.70
23	26.30	19.37	12.80	5.20	0.43	0.00	0.00	0.00	1.80	7.47	16.67	26.00
24	26.00	20.33	12.00	4.93	0.27	0.00	0.00	0.00	1.80	8.53	17.57	28.43
25	27.93	21.10	11.27	3.97	0.63	0.00	0.00	0.00	1.27	8.10	15.93	31.37
26	29.00	20.57	11.37	4.07	0.27	0.00	0.00	0.00	1.60	7.70	15.03	28.70
27	27.97	19.70	11.03	4.70	0.47	0.00	0.00	0.00	2.07	9.03	14.60	23.33
28	25.70	20.80	10.33	4.63	0.47	0.00	0.00	0.03	1.83	9.50	17.30	22.77
29	23.83	4.93	10.90	3.80	0.67	0.00	0.00	0.07	2.10	8.53	18.30	24.47
30	24.33		11.33	2.70	0.53	0.00	0.00	0.00	2.20	7.10	18.90	24.17
31	25.40		10.90		0.43		0.00	0.00		6.03		22.50
Calendar Total	826	636	447	203	49	1	0	0	20	175	438	742
Cycle Total	798	806	518	324	108	16	0	0	1	77	311	579

NON-LEAP YEAR TOTAL	3,538
LEAP YEAR TOTAL	3,553

Note: Degree Days for February 29 must be multiplied by 4 to arrive at the true DDD for this day.
NOTE: AVERAGE IS FOR THE 30 YEAR PERIOD ENDED: May, 2011.

ATTACHMENT WHN-4

Revenue Comparison

Attachment WHN-4
Schedule 1

Piedmont-Nashville
Attrition Period Revenue Summary Comparison

Line No.	Consumer Advocate	Demand Units	Bills	Sales Volumes	Gross Margin A/
1	**Residential**		1,815,891	111,302,133	$55,025,059
	Commercial				
2	Small General Service		198,023	50,982,004	$23,099,911
3	Medium General Service		4,924	15,667,597	5,703,459
4	**Total Commercial**		**202,947**	**66,649,601**	**$28,803,370**
	Industrial				
5	Firm Sales	61,947	475	5,628,480	1,154,835
6	Interruptible Sales		15	19,280	6,378
7	Firm Transportation	157,725	1,021	18,057,200	3,223,277
8	Interruptible Transportation		653	80,960,990	4,043,748
9	**Total Industrial**	**219,672**	**2,164**	**104,665,950**	**$8,428,238**
10	**Special Contract**		12	5,447,130	434,249
11	**Sales for Resale**	2,400	31	103,120	28,481
12	**Total Sales & Transportation**	**222,072**	**2,021,045**	**288,167,934**	**$92,719,397**
13	Other Revenues				1,884,565
14	**Total Revenues**				**$94,603,962**

Line No.	Company	Demand Units	Bills	Sales Volumes	Gross Margin B/
15	**Residential**		1,805,924	110,736,270	$54,662,151
	Commercial				
16	Small General Service		195,782	51,281,220	$23,081,065
17	Medium General Service		4,842	15,438,360	5,602,239
18	**Total Commercial**		**200,624**	**66,719,580**	**$28,683,304**
	Industrial				
19	Firm Sales	61,947	475	5,628,480	1,154,835
20	Interruptible Sales		15	19,280	6,378
21	Firm Transportation	157,725	1,021	18,057,200	3,223,275
22	Interruptible Transportation		641	77,217,770	3,930,604
23	**Total Industrial**	**219,672**	**2,152**	**100,922,730**	**$8,315,092**
24	**Special Contract**		36	8,673,330	624,617
25	**Sales for Resale**	2,400	31	103,120	28,481
26	**Total Sales & Transportation**	**222,072**	**2,008,767**	**287,155,030**	**$92,313,645**
27	Other Revenues				2,005,089
28	**Total Revenues**				**$94,318,734**

A/ CAPD Revenue Workpaper R-13.00.
B/ Company Exhibits DRC-1 and PKP-1.

ATTACHMENT WHN-5

Gas Cost Calculation

Piedmont-Nashville
Gas Cost Calculation

Attachment WHN-5
Schedule 1

Line No.	Consumer Advocate	Revenue	Margin	Gas Cost A/
1	Residential (301)	$111,860,380	$55,025,059	$56,835,321
	Commercial			
2	Small General Service (302)	$49,080,850	$23,099,911	$25,980,939
3	Medium General Service (352)	13,423,825	5,703,459	7,720,366
4	**Total Commercial**	**$62,504,675**	**$28,803,370**	**$33,701,305**
	Industrial			
5	Firm Sales (303)	$4,160,219	$1,154,835	$3,005,384
6	Interruptible Sales (304)	16,210	6,378	9,831
7	Firm Transportation (313)	4,039,490	3,223,277	816,213
8	Interruptible Transportation (314)	4,098,048	4,043,748	54,300
9	**Total Industrial**	**$12,313,966**	**$8,428,238**	**$3,885,728**
10	Special Contract	552,454	434,249	118,205
11	Sales for Resale (310)	89,544	28,481	61,063
12	**Total Sales & Transportation**	**$187,321,019**	**$92,719,397**	**$94,601,622**

Line No.	Company	Revenue	Margin	Gas Cost B/
13	Residential (301)	$111,208,831	$54,662,151	$56,546,680
	Commercial			
14	Small General Service (302)	$49,214,518	$23,081,065	$26,133,453
15	Medium General Service (352)	13,209,710	5,602,239	7,607,471
16	**Total Commercial**	**$62,424,228**	**$28,683,304**	**$33,740,924**
	Industrial			
17	Firm Sales (303)	$4,160,218	$1,154,835	$3,005,383
18	Interruptible Sales (304)	16,210	6,378	9,832
19	Firm Transportation (313)	4,039,484	3,223,275	816,209
20	Interruptible Transportation (314)	3,984,729	3,930,604	54,125
21	**Total Industrial**	**$12,200,641**	**$8,315,092**	**$3,885,549**
22	Special Contract	742,822	624,617	118,205
23	Sales for Resale (310)	89,544	28,481	61,063
24	**Total Sales & Transportation**	**$186,666,066**	**$92,313,645**	**$94,352,421**

A/ CAPD Revenue Workpapers R-13.02.
B/ Company Exhibit DRC-1.

ATTACHMENT WHN-6

CAPD Proposed Rate Design

Piedmont-Nashville
CAPD Proposed Rate Design

Attachment WHN-6
Schedule 1

Tariff	Billing Determinants	Current Base Rates	Current Margin	Revenue Deficiency	Proposed Margin	Proposed Base Rates	Percent Increase
Residential:							
Customer Charges:							
Summer	1,055,850	$10.00	$10,558,498	$2,999,415	$13,557,913	$12.84	28.41%
Winter	760,041	$13.00	9,880,535	2,806,822	12,687,357	$16.69	28.41%
Total Customer Charge Margin	1,815,891		$20,439,033	$5,806,238	$26,245,271		28.41%
Commodity Charges:							
Summer Therms	20,613,155	$0.27000	$5,565,552	$0	$5,565,552	$0.27000	0.00%
Winter Therms	90,688,978	0.32000	29,020,473	0	29,020,473	0.32000	0.00%
Total Commodity Charge Margin	111,302,133		$34,586,025	$0	$34,586,025		0.00%
Total Residential		1	$55,025,058	$5,806,238	$60,831,296		10.55%
				$5,806,238	$60,831,296		
Commercial:							
Small General Service:							
Customer Charges:							
Summer	114,819	$29.00	$3,329,743	$1,413,323	$4,743,066	$41.31	42.45%
Winter	83,204	$29.00	2,412,926	1,024,177	3,437,103	$41.31	42.45%
Total Customer Charge Margin	198,023		$5,742,669	$2,437,500	$8,180,169		42.45%
Commodity Charges:							
Summer Therms	13,536,997	$0.30300	$4,101,710	$0	$4,101,710	$0.30300	0.00%
Winter Therms	37,445,007	0.35400	13,255,533	0	13,255,533	0.35400	0.00%
Total Commodity Charge Margin	50,982,004		$17,357,243	$0	$17,357,243		0.00%
Total Small General Service			$23,099,912	$2,437,500	$25,537,412		10.55%
Medium General Service:							
Customer Charges:							
Summer	2,855	$75.00	$214,128	$348,956	$563,084	$197.22	162.97%
Winter	2,069	$75.00	155,169	252,873	408,042	$197.22	162.97%
Total Customer Charge Margin	4,924		$369,297	$601,828	$971,125		162.97%
Commodity Charges:							
Summer Therms	4,160,139	$0.30300	$1,260,522	$0	$1,260,522	$0.30300	0.00%
Winter Therms	11,507,458	0.35400	4,073,640	0	4,073,640	0.35400	0.00%
Total Commodity Charge Margin	15,667,597		$5,334,162	$0	$5,334,162		0.00%
Total Medium General Service			$5,703,459	$601,828	$6,305,287		10.55%
Total Commercial		0.310650974	$28,803,371	$3,039,328	$31,842,699		10.55%
				$3,039,328	$31,842,699		
Industrial:							
Customer Charges	2,164	$300.00000	$649,200	$889,347	$1,538,547	$710.97	136.99%
Volumetric Charges:							
Step 1 - 0 to 15,000 Therms per Month	23,191,580	$0.09742	$2,259,324	$0	$2,259,324	$0.09742	0.00%
Step 2 - 15,001 to 40,000 Therms per Month	16,584,970	0.08953	1,484,852	0	1,484,852	0.08953	0.00%
Step 3 - 40,001 to 90,000 Therms per Month	13,129,180	0.06450	846,832	0	846,832	0.06450	0.00%
Step 4 - Over 90,000 Therms per Month	51,760,220	0.02764	1,430,652	0	1,430,652	0.02764	0.00%
Total Volumetric Charges	104,665,950		$6,021,660	$0	$6,021,660		0.00%
Demand Charges	219,672	$8.00000	$1,757,378	$0	$1,757,378		0.00%
Total Industrial		0.09090	$8,428,238	$889,347	$9,317,585		10.55%
				$889,347	$9,317,585		
Other:							
Special Contracts			$434,249	$45,822	$480,071	Proprietary	10.55%
Sales for Resale:							
Customer Charges	31	$0.00	$0	$3,005	$3,005	$96.95	100%
Demand Charges	2,400	8.00000	19,200	0	19,200	8.00000	0%
Volumetric Charges	103,120	0.09000	9,281	0	9,281	0.09000	0%
Total Sales for Resale			$28,481	$3,005	$31,486		10.55%
Total Other		0	$462,730	$48,827	$511,557		10.55%
				$48,827	$511,557		
Miscellaneous Service Revenue:							
Forfeited Discounts			$1,564,421	$79,654	1,644,075		5.09%
Bad Check Charges			51,090	0	51,090		0.00%
Reconnect Charges			241,448	0	241,448		0.00%
Other Miscellaneous Items			27,606	0	27,606		0.00%
Total Miscellaneous Service Revenue			$1,884,565	$79,654	$1,964,219		4.23%
				$79,654	$1,964,219		
Total Base Rate Margin			$94,603,962	$9,863,394	$104,467,356		10.43%
				9,863,394	104,467,356		

SOURCE: CAPD Workpaper R-14.00.

ATTACHMENT

6

EXHIBIT ________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Vectren Energy Delivery of Ohio, Inc., for Authority to Amend its Filed Tariffs to Increase the Rates and Charges for Gas Services and Related Matters.	)))))	Case No. 07-1080-GA-AIR
In the Matter of the Application of Vectren Energy Delivery of Ohio, Inc., for Approval of An Alternative Rate Plan for a Distribution Replacement Rider to Recover the Costs of a Program for the Accelerated Replacement of Cast Iron Mains and Bare Steel Mains and Service Lines, a Sales Reconciliation Rider to Collect Difference Between Actual and Approved Revenues, and Inclusion in Operating Expense of the Costs of Certain Reliability Programs.	)))))))))))))	Case No. 07-1081-GA-ALT

DIRECT TESTIMONY
Of
WILLIAM H. NOVAK

On Behalf of
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
10 West Broad Street, Suite 1800
Columbus, Ohio 43215

July 23, 2008

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ATTACHMENTS

SCHEDULES

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD, PLEASE.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am a Certified Management Accountant, and am also licensed to practice as a Certified Public Accountant.

My work experience has centered on regulated utilities for over 25 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee, where I was responsible for defending the utility's gas cost recovery and rate filings at a time when it was completely exiting the gas merchant function in Georgia, and employing a straight fixed variable ("SFV") rate design for each of its individual customers. I also served for two years as the Vice President of Regulatory Compliance for Sequent Energy Management, a natural gas trading and optimization company in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am testifying on behalf of the Office of the Ohio Consumers' Counsel ("OCC").

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A4. My testimony will support certain OCC Objections to the Staff Report and address issues raised by those objections. Specifically I will address the following aspects of the Company's case:

- The process used to normalize test period sales for weather;
- The forecast of revenues under current rates for all customer classes;
- The allocation of the proposed rate increase to different customer classes;
- The rate design for the residential customer class;
- The Distribution Rate Rider ("DRR"); and
- The Sales Reconciliation Rider ("SRR").

Q5. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A5. I have reviewed the Vectren Energy Delivery of Ohio ("Vectren" or "the Company) Rate Case Application, along with the testimony and exhibits presented with their filing. In addition, I have reviewed the Company's workpapers related to the cost of service and revenue calculation supporting their filings. I have also reviewed the Company's responses to the data requests submitted by the Staff and Eagle Energy, as well as the OCC in these same areas. Finally, I have reviewed the Staff Report and the Eagle Report along with workpapers provided to the OCC in support of their conclusions.

I. WEATHER NORMALIZATION

Q6. PLEASE EXPLAIN THE PROCESS OF WEATHER NORMALIZATION.

A6. Generally speaking, gas sales to the residential and small commercial customer classes are highly dependent upon changes in weather. In addition, weather normalization can often be appropriate to individual industrial customers that use natural gas solely for heating load as opposed to a process load.

To the extent that any of these customer classes use gas for heating, then the severity of weather impacts their demand for gas. That is to say that during colder than normal periods, the Company will generally increase their sales to the residential and small commercial customer classes. Likewise in periods of warmer than normal weather, the Company's sales will generally decrease to the same customer classes.

Weather normalization in a rate case represents an adjustment to the actual historical gas sales volumes to account for the impacts of the differences between actual and normal weather. In other words, the historical values of the residential and small commercial customer classes are adjusted to what they ***would have been*** if normal weather had occurred. This adjustment to "normal" is necessary because we don't know precisely what any future years' weather will be; therefore we assume in a rate case that weather will be normal and we adjust accordingly.

Q7. HOW IS NORMAL WEATHER DETERMINED?

A7. In the United States, the most widely relied upon source of weather data is from the National Oceanic and Atmospheric Administration ("NOAA"). To my knowledge, NOAA has always calculated normal weather as a 30 year average of the actual daily weather observed. NOAA recalculates this normal weather average every 10 years, with the last calculation taking place for the 30 year period ended December 31, 2000. The NOAA calculation of normal weather has traditionally been accepted and utilized by public utility commissions in gas distribution rate cases.

Q8. HAS THE COMPANY ADOPTED A 30 YEAR AVERAGE AS NORMAL IN ITS RATE CASE?

A8. No. Instead of the 30 year average, the Company has proposed using a 10 year average of actual weather as a proxy for normal weather. NOAA has calculated the 30 year average of weather to be 5,690 heating degree days ("HDD") whereas the Company has adopted a 10 year average of 5,388 HDD for a difference of 302 HDD or 5.3%. The impact of this change in computing normal weather from 30 years to 10 years results in an increase in the Company's revenue requirements of approximately $1.7 million.

As shown on Schedule WHN-1, during the 10 year period used by the Company to calculate normal weather, the deviation of actual heating degree days experienced from normal weather for both 10 year and 30 year averages produced the following results:

	10 Year Average	**30 Year Average**
Years Warmer Than Normal	4	7
Years Colder Than Normal	6	3

As expected, both the 10 year average and the 30 year average produced results that were on both sides of the normal average. As a result, there appears to be very little evidence in support of the Company's conclusions that 30 year weather is no longer appropriate since the evidence shows that during the last 10 years the actual weather experienced was both warmer and colder than the 30 year average. It therefore appears that Vectren has elected to use a 10 year average of weather in order to increase the Company's revenue requirement. I doubt that such an action would be requested if the actual weather experienced had been materially colder than the normal during this 10 year period.

Q9. WHAT IS THE COMPANY'S BASIS FOR USING A 10 YEAR AVERAGE FOR NORMAL WEATHER?

A9. The Company's sole basis for adopting a 10 year average for normal weather appears to be contained within the four page testimony of Company witness Michael F. Gorman who states very clearly that his analysis "* * * is purely statistical and in no way either climatological or meterological in nature."[1] However, the source weather data used by Mr. Gorman as the basis for his analysis is completely climatological. Mr. Gorman then concludes in his analysis that "* * * from a statistical perspective, a 30 year weather history provided less accuracy (and therefore greater bias) than shorter historical periods."[2] This conclusion appears to be the Company's complete rationale for adopting a 10 year average of weather as normal.

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[1] Gorman Prefiled Direct Testimony at 2.

[2] Id. at 3.

Q10. IS MR. GORMAN'S CONCLUSION THAT 30 YEAR WEATHER IS LESS ACCURATE THAN A 10 YEAR PERIOD CORRECT?

A10. From a strictly statistical point of view a shorter time period may be more accurate than a longer period. However, Mr. Gorman's analysis is simply a self-fulfilling prophecy. If one calculates the average weather for a 10 year period, one would expect that 10 year average to be closer to the most recent weather actually realized than a 30 year average of weather. Under this logic, a five year, three year or even one year average would be more "accurate" than the 30 year average. However, this does not mean that there is any "predictive" value in using a shorter average. Weather is not something that is readily predicted from the results of the previous year or even the most recent 10 years. While we can make observations based on historic periods that take into account both recent and long term trends, it would not be reasonable to focus too much on either the most recent or the long term past. Instead, some form of combination is necessary. The NOAA 30 year average provides that combination because it reflects the recent past while at the same time recognizing any recent anomalies that need to be mitigated. Otherwise a stretch of 2 or 3 years of extremely cold or warm weather could seriously skew the analysis. The best method for determining what is "normal" is to use a longer term average as NOAA does, since this longer period takes into account many of the anomalies that a shorter period would miss. In fact, the Company actually puts their sales budget together using a 30-year average of weather. The NOAA 30-year average is far less volatile than the Company's choice of the most recent 10-

year average, which appears to have been chosen for the sole purpose of increasing the Company's revenue requirement.

Q11. DID THE STAFF ADOPT A 30 YEAR AVERAGE FOR NORMAL WEATHER?

A11. No. The Staff recommended the adoption of the Company's 10 year average for normal weather. Page 8 the Staff Report states that Staff "* * * agree[s] with normalizing test year sales volumes to recognize the average use per customer ("AUPC") based on a ten year actual heating degree day average." This is a policy departure from past practice of the Staff, and there is no further mention in the Staff Report as to how they reached this conclusion.

I have reviewed other recent Staff Reports in gas distribution rate cases with respect to weather normalization and noted that in the following cases weather normalization was not even addressed, and I am therefore assuming that a 30 year average was used:

Case	**Company**
94-0987	Columbia Gas of Ohio
95-0488	Eastern Natural Gas Company
95-0656	Cincinnati Gas & Electric
97-1724	Northeast Ohio Gas Company
07-0194	Waterville Gas Company
07-0689	Suburban Gas Company

However, weather normalization was specifically mentioned in the Staff Report for these other recent cases with recommendations as noted:

Case	Company
01-1228	Cincinnati Gas & Electric *Staff recommended a10 year average*
03-2170	Northeast Ohio Gas Company *Staff recommended a 30 year average*
07-0829	East Ohio Gas Company *Considered as part of a decoupling mechanism*

Of special interest, the only time that the Staff recommended a 10 year average for normal weather, in the 2001 CG&E rate case noted above, the case was ultimately settled by the parties through a stipulation presented to and accepted by the Commission. Therefore the Commission has not previously made a specific decision on the policy issue of using a 10 year average for normal weather.

However, the method and analysis utilized by the Staff to calculate VEDO's normal residential sales volumes and average sales per customer are in error. I believe that these errors contributed to the Staff's recommendation that the Commission adopt the Company's proposed 10-year average for normal weather.

Q12. PLEASE IDENTIFY THE ERRORS CONTAINED IN THE STAFF'S CALCULATION.

A12. On page 33 of the Staff Report, a presentation is made of residential weather normalized use per customer and weather normalized sales since 1990. I was able to obtain the Staff's workpapers supporting this calculation, which I have included in Attachment WHN-2 to my testimony, and discovered two errors in the Staff's analysis.

First, as shown on pages 1 – 4 of Attachment WHN-2, although the Staff obtained the correct 30 year monthly normal heating degree days from NOAA, they were incorrectly totaled to 5,388 normal degree days instead of 5,690 per the NOAA report. This error produced a 5.5% error in the Staff's calculation of normal use per customer.[3]

The second error involved the Staff's methodology for the calculation of normal sales. The Staff began by taking the percentage difference between the annual actual heating degree days and the incorrectly calculated normal heating degree days of 5,388. The Staff then applied this percentage change in heating degree days to the actual sales and actual sales per customer to get the normalized use per customer and normalized sales contained on page 33 of the Staff Report.

Q13. IS THE STAFF'S METHODOLOGY OF COMPUTING THE NORMAL SALES PRESENTED ON PAGE 33 OF THE STAFF REPORT CORRECT?

A13. No. The Staff's methodology assumes a one-to-one relationship between the percentage change in weather to the percentage change in residential sales. Since other anomalies can and do impact residential sales (conservatión, smaller houses, etc.) this one-to-one relationship rarely occurs. In my opinion, weather normalization is best calculated by using linear regression on the monthly sales per customer with the actual weather experienced over multiple 12-month periods. An equation from this regression analysis can then be applied to normal monthly weather. This type of analysis also provides a coefficient of correlation statistic that measures the change in sales per customer that can be explained by changes in weather.

Q14. HAVE YOU PERFORMED SUCH A REGRESSION ANALYSIS?

A14. Yes. The summary results of my weather normalization using linear regression are presented on Schedule WHN-2. As can be seen from this data, over the latest six year period from 2002 – 2007, residential weather normalized use per customer has actually increased.

The results of the weather normalization for commercial customers have not been finished, due to a delay in data previously requested from the Company and provided to the OCC on July 18. The results from the analysis of this information will be presented to the Commission in supplemental testimony.

Q15. WHAT CONCLUSIONS DO YOU MAKE FROM THIS ANALYSIS?

[3] While 5,388 heating degree days equals the 10 year average used by the Company, the individual

A15. I conclude that the apparent basis for the Staff's support of the Company's proposal to adopt a ten year average for normal weather based on declining normalized usage per customer is in error. As a result, there is no independently valid basis for the Staff's acceptance of the Company's ten year proposal. I certainly don't oppose a change in policy when new data indicate a change should be made, however there is no corroborating data in this case to suggest that a change from a 30 year average of weather to a 10 year average should be made.

Q16. DO YOU EXPECT WEATHER NORMALIZED RESIDENTIAL SALES PER CUSTOMER TO REMAIN CLOSE TO THE LEVELS CALCULATED HERE IN THE FUTURE?

A16. At least for the short term future, (representing the first 12 to 18 months that any rates set by the Commission would be in effect), I do expect the residential weather normalized sales per customer to remain close to the levels presented above. As shown by the data in Schedule WHN-1, the residential normal sales per bill over the last six years has only varied minimally from the test period with a low of 0.0070 MMcf per bill in 2006 to a high of 0.0079 per MMcf per bill in 2004.

However, over longer periods of time, normal residential sales per customer may well decline. Erosion of average sales per customer is nothing new, and has been experienced by gas utilities since long before current concerns about weather.

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monthly amounts used by the Staff in their analysis do not total to this amount.

Because natural gas is a scarce commodity, simple economics dictate that better technology will always be deployed to make its use more efficient. We've seen this in the past with better insulated homes and more efficient energy appliances. However, these changes have very little to do with weather, since approximately 99%[4] of total residential sales can be explained by changes in weather.

Another consideration that can cause erosion of average sales per customer is the Company's annual expansion of plant in service. This is especially true when the average use per customer from new customers is less than the embedded average use from the existing customers. However, for the last four years the Company's addition to plant in service has averaged \$20.7 million while its average depreciation expense has been over \$26.4 million during this same period.[5] This means that the Company has limited its plant expansion to only a portion of those dollars provided from internally generated funds.

Q17. WHAT DO YOU RECOMMEND THE COMMISSION ADOPT FOR PURPOSES OF CALCULATING NORMALIZED TEST YEAR VOLUMES IN THIS CASE?

A17. I recommend that the Commission reject the 10 year average for normal weather proposed by the Company and accepted by the Staff, and instead continue to

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[4] Regression correlation factors from Schedule WHN-1.

[5] Company filing, Schedule C-11.1, Line 6 and Schedule C-11.2, Line 6.

utilize a 30 year average for normal weather as calculated by NOAA since it provides a more reasonable basis for analyzing the Company's normal sales per customer. I therefore recommend that the Commission adopt the test period weather normalized sales per bill of 0.0074 MMcf per bill for the residential customer class as shown on Schedule WHN-2. A recommendation for weather normalized sales per bill for the commercial customer class will be made available in supplemental testimony.

II. REVENUE FORECAST

Q18. HAVE YOU REVIEWED THE COMPANY'S REVENUE CALCULATION?

A18. Yes. The Company began its revenue calculation from its revenue budget. However, starting the revenue calculation from the Company's budget requires an acceptance of the Company's budgeting process -- and the assumptions that underlie that process -- which I find to be unreasonable. I conclude this because the individual components making up the Company's complete operating budget have not been identified and verified. As a result, I experienced significant delays in obtaining historical sales and customer data needed to enable me to put together my own analysis.[6]

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[6] This same dilemma was also noted on page 31 of the Eagle Energy Report which states as follows: "While there seems to be adequate budget documentation for capital and operating expenses, similar documentation does not appear to exist for the revenue or margin budgeting process."

For the residential and commercial customer classes, my approach was to first normalize the actual test period volumes for 30-year average weather as previously noted, in order to compute the normal sales per customer. I then increased the test period number of customers by the four year annual average increase in customers actually experienced. The adjusted test period sales volumes and customers were then priced out at current rates to arrive at the revenues under present rates.

For the industrial customer class, I began with the actual test period sales volumes and bills, and then made adjustments for known changes. These known changes typically included the new customers and closings that were specifically identified by the Company. Again, the adjusted test period sales volumes and customers were then priced out at current rates to arrive at the revenues under present rates.

The result of my revenue forecast is shown on Schedule WHN-3. In addition, a comparison of the OCC's revenue forecast with the Company and the PUCO Staff can be found on Schedule WHN-4. At this time, only the results of the revenue forecast for the residential customer class has been completed. The revenue forecast for commercial and industrial customers has not been finished, due to a delay in data previously requested from the Company and later provided to the OCC on July 18. The results from the analysis of this information for commercial and industrial customers will be presented to the Commission in supplemental testimony.

III. RATE INCREASE ALLOCATION

Q19. HAVE YOU REVIEWED THE COMPANY'S PROPOSED RATE INCREASE ALLOCATION?

A19. Yes. As shown on Schedule WHN-5, the residential customer class currently provided 64.27%[7] of the Company's base rate revenue during the test period. The Company has proposed that 84.68% of their proposed increase be allocated to the residential customer class consisting of the sales, transportation and dual fuel tariffs. As derived from Table 1a of the Staff Report and presented on Schedule WHN-5, the Staff has proposed that 62.03% of their proposed rate increase be allocated to the residential customer class.

Q20. DO YOU AGREE WITH THE STAFF RECOMMENDATION?

A20. While I don't agree with the Staff's methodology for the rate increase allocation, I do agree with the end results produced by it for the residential customer class. Generally, I believe that any increase in revenue requirements approved by the Commission should be allocated equally to **all** customer classes based on the test period gross margin. When such an adjustment is made, it results in roughly the same rate increase allocation as the Staff has proposed. I therefore support the Staff's recommendation of the rate increase allocation for this case.

[7] Excluding miscellaneous revenues.

IV. RESIDENTIAL RATE DESIGN

Q21. HAVE YOU REVIEWED THE COMPANY'S PROPOSED CHANGES TO ITS RESIDENTIAL (RATE 310 AND 315) TARIFFS?

A21. Yes. The Company has asked to recover its entire base rate increase allocated to the residential customer class through an increase in the fixed monthly customer charge. This type of rate design is generally known as a straight fixed variable ("SFV") rate design. Under the Company's proposal, the residential monthly customer charge would initially be increased from its present fixed rate of $7.00 per customer per month to $10.00 per customer per month during the summer months (from May to October) and from $7.00 per customer per month to $16.75 per customer per month during the winter heating season (from November to April). The Company then went further, and proposed a second stage (revenue neutral) increase in the fixed residential monthly customer charge from $10.00 per customer per month to $11.96 per customer per month during the summer months and from $16.75 per customer per month to $20.04 per customer per month during the winter heating season that would take place on November 1, 2010. Finally, the Company proposes to move to complete recovery of costs allocated to the residential class through a fixed monthly customer charge (with no volumetric rate) in its next rate case.

Q22. DOES THE STAFF AGREE WITH THE COMPANY'S PROPOSAL FOR THIS CHANGE IN THE RESIDENTIAL MONTHLY CUSTOMER CHARGE?

A22. Yes the Staff appears to accept the SFV rate design. Staff, however, has proposed a lower volumetric charge that reflects their adjustment to the Company's case. The Staff is basically proposing the same changes to the residential customer's monthly customer charge, as proposed by the Company.

Q23. WHAT RATIONALE DOES THE STAFF AND COMPANY CITE FOR THIS CHANGE IN THE MONTHLY RESIDENTIAL CUSTOMER CHARGE?

A23. Both the Staff[8] and Company[9] point to the continuing decline in sales per customer as the biggest reason for the change. The Staff goes on to further point out that the Company "* * * has seen the recovery of distribution costs deteriorate as the volume of gas used by residential customers has decreased."[10] The Staff also points out that recovery of allocated residential costs through a fixed charge will levelize the distribution component of a customers' bill providing rate certainty.

Q24. DO YOU AGREE WITH THE STAFF'S RATIONALE FOR THIS CHANGE?

[8] Staff Report at 30.

[9] Benkert Direct Testimony at 9.

[10] Staff Report at 30.

A24. No. As pointed out in Section I of my testimony, the Staff's analysis of declining weather normalized use per customer for the residential customer class is in error. While actual sales per customer have declined, the average weather normalized residential usage per customer has held steady between 7 to 8 Mcf per bill for the last six years. It is important to distinguish between actual and weather normalized usage since rates are set on weather normalized sales volumes. There is simply no corroborating evidence in the record for this rate case supporting a decline in residential weather normalized use per customer. In fact, as shown on Schedule WHN-2, just the opposite has occurred; weather normalized residential average use per customer has actually increased during the test period from the preceding year.

In addition, the Staff's point that a flat monthly distribution charge for residential customers will somehow provide customers with price certainty is also faulty. The distribution charge is relatively minor in comparison to a customer's total bill that includes gas costs which fluctuate monthly and other surcharges. I doubt if any residential customers would perceive an added benefit to price certainty from a fixed monthly distribution charge.

Q25. ARE THERE OTHER REASONS THAT YOU OPPOSE THE MOVE TO A FIXED MONTHLY CUSTOMER CHARGE?

A25. Yes. First, I have never witnessed any residential customers requesting a change in their rate structure to a flat monthly distribution charge. For better or for worse, residential customers are accustomed to paying for gas service as gas is consumed. Such a significant change in residential rate design is likely to cause customer confusion as well as a negative reaction, especially during periods of low usage in the summer months.

Second, adoption of a flat monthly distribution charge for residential service removes an important future rate design tool from the Commission's discretion. A typical change to volumetric rates is more akin to "fine tuning" a rate change while a change to the monthly customer charge is similar to rate design by sledge hammer. It may well be that future costs are better recovered through volumetric rates, but only if they are blended with other existing costs.

Third, it is inappropriate that the move towards a fixed monthly distribution charge is only applied to residential and small general service customers. Other gas utilities have applied separate demand charges to recover their fixed costs from industrial customers with a corresponding offset to the volumetric rate. However, no such rate design has been suggested for the industrial customer class by either the Staff or the Company. From a policy perspective, it appears inappropriate to apply the cost recovery principles of SFV to one class without applying it to all other customer classes.

Fourth, the immediate adoption of SFV rate design adversely impacts low income, non-Percentage of income Payment Plan ("PIPP"), customers with the largest percentage increase in rates. It also transfers costs from higher volume customers to these same lower volume customers. These are the very customers who can least afford this change in rate design policy. A rate increase of any kind always presents an undue hardship for these customers. However, a change to SFV rate design presents non-PIPP, low income customers with a second rate increase on top of an increase in revenue requirements.

Finally, from a policy perspective, SFV rate design sends inaccurate pricing signals to the customer and negatively impacts conservation efforts by reducing the volumetric rates, which then lengthens the payback period of conservation investments. In this case, the Company has proposed spending an additional $2.9 million annually on conservation programs.[11] The full benefits of these conservation programs will be diluted by a rate design that fails to recognize or reward customers for conservation – which is a state policy objective.

Q26. ARE YOU AWARE OF THE OHIO COMMISSION'S RECENT DECISION REGARDING FIXED MONTHLY DISTRIBUTION CHARGES FOR

[11] Direct Prefiled Testimony of Company witness Rose at14 and Staff Report at 48.

***RESIDENTIAL CUSTOMERS IN THE DUKE ENERGY OHIO RATE CASE?*[12]**

A26. Yes. In that case, the Commission adopted a fixed monthly distribution charge for residential customers based largely on the evidence presented showing a declining use per residential customer. However, the Commission must make a decision in this case based on the specific facts and information presented in the record. Here, unlike in the Duke case, there is no corroborating evidence presented showing that the average weather normalized customer usage is declining. Having said that however, even if there was corroborating evidence presented demonstrating that the average weather normalized customer usage had declined, that would not have been in and of itself a sufficient reason to alter the rate design in such a radical manner.

Q27. WHAT TYPE OF RATE DESIGN DO YOU PROPOSE FOR RESIDENTIAL CUSTOMERS?

A27. I recommend limiting any increase in the existing fixed monthly customer charge from $7.00 per customer per month to $10.00 per customer per month. This change equals the monthly customer charge adjustment ($7.00 - $4.00) approved in the Company's last rate case.[13] This change also equals the monthly charge ($10.00) that the Company has proposed for the summer months. I would then

[12] PUCO Case No. 07-589-GA-AIR.

[13] Case 04-0571-GA-AIR.

propose that the balance of the increase allocated to the residential customer class be placed on a single volumetric rate of $0.08046/Ccf as shown on Schedule WHN-5. A single volumetric rate should help create greater conservation incentives for more residential customers than the existing two-tier declining block rate structure. Schedule WHN-5 provides an illustration of my recommended rate design for residential customers.

Q28. WHAT ARE THE ADVANTAGES OF YOUR RATE DESIGN?

***A.*28** First, it is a rate design structure that the Company's residential customers are already familiar with. As a result, there should not be the same type of confusion with this rate design as would be seen with the Company's proposed shift to an SFV rate design. Secondly, the increase from this rate design to individual customers likely meets their expectations based on how their bill has changed from past rate cases. In addition, this rate design also preserves volumetric rates to allow for fine tuning of any future cost recovery by the Commission. Finally, it is a rate design that sends more accurate price signals to the customer and encourages conservation.

Q29. DO YOU HAVE ANY COMMENTS TO MAKE IF THE COMMISSION SHOULD ELECT TO ADOPT SFV RATE DESIGN IN SPITE OF YOUR ARGUMENTS?

A29. Yes. If the Commission is committed to the policy concept of an SFV rate design, which the OCC does not support, then I would urge it to gradually implement its impact over several periods instead of all at once in a single rate case. The Company has proposed to partially implement SFV immediately and then proposed a second revenue neutral rate change on November 1, 2010, which would increase the current monthly residential customer charge from $7.00 per customer per month to $20.04 per customer per month. This change is simply too large to consider in a single rate case.

Instead of this rapid pace, I would recommend that the Commission consider limiting an annual change of no more than $1.00 to $2.00 every year until the Company's next rate case. Slowly changing the current rate design from volumetric cost recovery to a fixed cost recovery would allow the Commission to gauge the customer's reaction to SFV implementation and make adjustments accordingly. However, I want to emphasize that this level of increase in the customer charge is not supportable and from a policy perspective is not a good direction to take. I would urge the Commission to hold the line on keeping customer charges low and retaining the volumetric charge.

V. DISTRIBUTION RATE RIDER

Q30. DO YOU SUPPORT CONTINUING THE COMPANY'S PROPOSED DISTRIBUTION RATE RIDER ("DRR")?

A30. No. While I do recognize the safety concerns expressed by the Commission Staff regarding the need for accelerated bare steel and cast iron main replacement, the DRR has effectively become a single issue ratemaking mechanism. The DRR also represents by far the single biggest rider ever proposed by the Company. According to the Staff Report, the cost of the DRR will be approximately $338 million[14] over 20 years which is significantly larger than the Company's existing rate base of approximately $228 million.[15] The annual revenue requirements from such an increase would be approximately $42 million, and spread out over 20 years the DRR will result in an average increase in rates of approximately $2.1 million each year. I have been advised by OCC Counsel that single issue ratemaking is inconsistent with Ohio's general ratemaking provisions of Chapter 4909 of the Revised Code.

Additionally, I have concerns with certain other aspects of the DRR program that center on the approval process for a substantial and material rate increase outside of the normal rate case process. This accelerated process that is proposed to implement DRR rates cuts short the time that any stakeholder would normally have to scrutinize the changes if made within the rate case process. Moreover the DRR examines only one distinct expense item without considering whether there

[14] Staff Report at 41.

are separate and offsetting adjustments negating the need for the rider, either in part or in whole.

Notwithstanding my previously stated concerns, if the Commission stands ready to approve the DRR, which I am not recommending, I would support in part the Commission Staff's recommendations with certain modifications.

The Staff's first recommendation extends the DRR for eight years, or until a subsequent rate case, whichever occurs first. However, I recommend that any extension be limited to four years, since this is typically the length of time between rates cases for the Company. This modification gives me some assurance that the DRR won't become a "runaway train" without the ability to modify its terms or eliminate it entirely. For example, the DRR could have an impact on other areas of the Company's income statement that have not yet been contemplated. It is impossible for these changes to be considered in base rates outside of the normal rate case process. A four-year time limit on the DRR extension will give intervening parties an opportunity to timely examine the progress and impact of the DRR on all phases of the Company's operations.

The Staff's second recommendation caps the DRR charge, including riser replacements at $0.90 per month. I support the concept of a limit on any DRR

[15] OCC Exhibit RCS-1.

charge. This cap provides the OCC with assurance that the total DRR charge won't get out of control, and provides customers with a known upper bound of base charges that can be applied to them.

VI. SALES RECONCILIATION RIDER

Q31. HAVE YOU REVIEWED THE SALES RECONCILIATION RIDER ("SRR") PROPOSAL CONTAINED IN THE ALT REG PLAN APPLICATION?

A31. Yes. The Company's existing SRR-A was approved in Case No. 05-1444-GA-UNC. The intended use of the SRR-A which was developed in that proceeding, was to decouple the link between gas consumption and the utility's opportunity to earn a fair return on the basis that this linkage was counterproductive to energy efficiency. In that proceeding, the Commission found "it is in the public interest, **in order to promote energy efficiency**, to decouple the link between gas consumption and the Company's ability to meet its revenue requirements."[16] In the present proceeding, the Company has proposed to implement SRR-A on the rate effective date, followed by a second SRR-B in order to "* * * track changes in base revenue recovery resulting from abnormal weather as well as other causes such as declining use per customer."[17]

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[16] Opinion and Order at 18, Case No. 05-1444-GA-UNC.
[17] Direct testimony of Company witness Ulrey, at 10.

SRR-A was designed to protect the Company from the effects of declining use per customer. SRR-B as proposed by the Company, goes one step further and also protects the Company from changes in sales volumes caused by abnormal weather in addition to the effects of declining use per customer not directly attributable to weather. In other words, SRR-B provides a ***guarantee*** (as opposed to the opportunity) for the Company to fully recover the revenues approved by the Commission.

Q32. WHAT RECOMMENDATION HAS BEEN MADE BY THE STAFF WITH REGARD TO SRR-A AND SRR-B?

A32. Staff appears to support the implementation of SRR-A, and concurs with the Company proposal to collect SRR-A deferrals over a one year period beginning with the rate effective date in this order. The Staff proposes to eliminate the SRR-B in favor of SFV rate design.[18]

Q33. WHAT ISYOUR POSITION WITH RESPECT TO SRR-A?

A33. My position is that the SRR-A is unreasonable and unlawful as a result of the process used to implement the rider and the lack of sufficient Demand Side Management (DSM) required for its implementation. As a result, the $5,152,213 in deferrals that the Company is now seeking to collect through the SRR-A are

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[18] Staff Report at 34.

unreasonable and unlawful based upon this same reasoning. My position reflects the OCC position taken in Case No. 05-1444-GA-UNC.

However, notwithstanding these objections to the contrary, if the Commission should decide to adopt the SRR-A, I would recommend that the deferrals created be recovered over a two year period, as opposed to the one year recovery supported by the Staff and the Company. Since the SRR-A deferrals were originally developed over a two year period, it only seems reasonable that they should be recovered over this same period of time.

Q34. WHAT ISYOUR POSITION WITH RESPECT TO SRR-B?

A34. While I do not agree with the Company's proposed changes to implement SRR-B, I do agree that the impact of SRR-B is preferable to the implementation of SFV rate design. I understand that decoupling is a measure that should only be adopted when appropriate procedures are followed (within the context of a full rate proceeding under R.C. 4929.05) and when comprehensive DSM is being proposed. I also understand that appropriate procedures have been followed in this proceeding related to the filing of the SRR-B proposal, and that the commitment to DSM by the Company in this case may warrant the use of this regulatory mechanism.

However, I disagree with the Company's proposal to add the effect of weather recovery to SRR-B. Abnormal weather in the gas distribution industry represents just one of the risks of doing business. Under the Company's proposal, the risk is shifted to Vectren's customers. I understand that the Company makes no adjustment to the equity return to account for this. Therefore, absent any adjustment to the Company's equity return, there should be no need for adjustment of the SRR to include the impact of abnormal weather.

Q34. DOES THIS COMPLETE YOUR TESTIMONY?

A34. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available. I also reserve the right to supplement my testimony in the event that the PUCO Staff fails to support the recommendations made in the Staff Report and /or changes in any position in the Staff Report.

CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing *Direct Testimony of William H. Novak* was served upon the persons listed below by regular U.S. Mail, postage prepaid, this 23rd day of July, 2008.

Maureen R. Grady
Assistant Consumers' Counsel

SERVICE LIST

Werner Margard
Attorney General's Office
Public Utilities Section
180 East Broad Street, 9th Floor
Columbus, OH 43215

John Dosker
General Counsel
Stand Energy Corp.
1077 Celestial Street Suite 110
Cincinnati, OH 45202-1629

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Ohio Partners for Affordable Energy
231 West Lime Street
P.O. Box 1793
Findlay, OH 45839-1793

ATTACHMENT

7

BEFORE
THE TENNESSEE REGULATORY AUTHORITY

PETITION OF BERRY'S CHAPEL UTILITY, INC. TO CHANGE AND INCREASE RATES AND CHARGES	)	Docket No. 11-00198

DIRECT TESTIMONY
of
WILLIAM H. NOVAK

ON BEHALF OF
THE CONSUMER ADVOCATE AND PROTECTION DIVISION
OF THE
TENNESSEE ATTORNEY GENERAL'S OFFICE

April 23, 2012

TABLE OF CONTENTS

ATTACHMENTS

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.[1]

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am a Certified Management Accountant, and am also licensed to practice as a Certified Public Accountant.

My work experience has centered on regulated utilities for over 30 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee. I also served for two years as the Vice President of Regulatory Compliance for Sequent Energy Management, a natural

[1] State of Tennessee, Registered Accounting Firm ID 3682.

gas trading and optimization entity in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am testifying on behalf of the Consumer Advocate & Protection Division ("CAPD" or "the Consumer Advocate") of the Tennessee Attorney General's Office.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A4. My testimony will support and address the CAPD's positions and concerns with respect to the Lynwood Utility's ("Lynwood", "Berry's Chapel" or "the Company's") Petition. Specifically, I will address the following:

i. CAPD's proposed attrition period results of operations, revenues and rate base calculations;

ii. CAPD's proposed rate design; and

iii. CAPD's position on various charges that have been incorrectly charged to the Company's customers.

The CAPD's attrition period expense calculations will be presented by Mr. Dave Peters. The CAPD's proposed cost of debt calculations will be presented by Dr. Chris Klein.

Q5. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A5. I have reviewed the Company's Rate Case Application as filed on November 15, 2011, along with the testimony and exhibits presented with their filing. In addition, I have reviewed the Company's workpapers supporting their attrition period revenue requirements. I have also reviewed the Company's responses to the relevant data requests submitted by the TRA as well the Company's responses to CAPD's discovery requests in these same areas. Finally, I participated in two separate on-site visits to the Company's office in Franklin along with other CAPD Staff during which I reviewed the Company's financial records.

Based upon information obtained through this process, I developed the financial work papers and exhibits to test the reasonableness of the Company's current rates. I then adjusted the historical test period to compensate for the net effects of all known and reasonably anticipated changes which might occur in the near term future.

I. ATTRITION PERIOD RESULTS OF OPERATIONS UNDER CURRENT RATES

Q6. MR. NOVAK, PLEASE EXPLAIN AND SUMMARIZE YOUR FINDINGS IN THIS CASE.

A6. CAPD Exhibit, Schedule 1, details our forecast of the Company's results of operations under presently approved rates. The CAPD's attrition average rate base is $1,135,068 which is equal to the Company's forecast. The CAPD's attrition period operating income under present rates is $-59,331 or $201,254 more than the Company's calculation of $-260,585. The CAPD's return on rate base under present rates is -5.23% or 1,773 basis points higher than the Company's return of -22.96%. The Company has requested a $398,853 increase in rates to produce an 8.90% overall return. The CAPD's analysis indicates that an increase of $152,064 in rates will be necessary to cover the Company's debt cost and will result in a rate of return of 7.50%.

II. <u>ATTRITION PERIOD REVENUE UNDER CURRENT RATES</u>

Q7. MR. NOVAK, HOW DID YOU CALCULATE THE ATTRITION PERIOD REVENUES OF $596,258 AS SHOWN ON CAPD EXHIBIT, SCHEDULE 3?

A7. The revenue calculations are detailed on CAPD Exhibit, Schedule 5. As shown on Schedule 5, I have taken the Company's test period billing determinants for its residential, commercial and special contract customers and applied the current TRA approved billing rates. In addition, I have included the Company's proposed attrition period inspection fee & tap fee revenue of $3,750.[2] However, I did not include any amount for late charges revenue since the Company does not have

[2] Schedule R/E of Company witness Ford.

approval by the TRA for this type of charge. As shown on CAPD Exhibit, Schedules 3 and 5, our attrition period revenue calculations under current rates produced $596,258 which is $2,849 more than the Company's calculation of $593,409.

III. ATTRITION PERIOD RATE BASE AND DEBT COST

Q8. MR. NOVAK, PLEASE EXPLAIN THE CAPD'S RATE BASE CALCULATION.

A8. As shown on CAPD Exhibit, Schedule 2 the CAPD has adopted the Company's rate base calculation of $1,135,068. However, for a non-profit entity such a Lynwood Utility, the CAPD doesn't believe that rate base is an integral part of the rate case as it is for other for-profit utilities under the TRA's jurisdiction. Instead of rate base, the CAPD believes that the focus needs to be placed on the Company's debt cost recovery.

As shown on CAPD Exhibit, Schedule 1, the Company's debt cost is $85,130 and we have included this amount in our revenue deficiency calculations. Our inclusion of a rate base schedule in this case has only been made to conform our exhibits to the format traditionally presented to the TRA. Dr. Klein's testimony will speak to the proper method of calculating the debt cost recovery in the CAPD's case.

Q9. DID YOUR REVIEW OF THE MATERIALS PROVIDED BY THE COMPANY CAUSE YOU TO QUESTION THE AMOUNT OF THE COMPANY'S DEBT COST FOR THE PERIODS RELEVANT TO THIS RATE CASE?

A9. No. We believe that the debt cost of $85,130 shown on CAPD Exhibit, Schedule appears to be reasonable given the debt reported on the Company's books and records.

Q10. ARE THERE ANY DEBTS SHOWN ON THE COMPANY'S BOOKS THAT DO NOT REQUIRE A PAYMENT DURING THE ATTRITION PERIOD RELEVANT TO THIS RATE CASE?

A10. Yes. Specifically, the Company's books show two notes payable and totaling $2.4 million to John and Tyler Ring. There is one note for $1.2 million to John Ring and one for the same amount to Tyler Ring. According to the information presented by the Company, payment on these notes will not begin until 2014. Therefore, they have been excluded from the calculations for this rate case.

Q11. DO THESE TWO NOTES PRESENT ANY CAUSE FOR CONCERN?

A11. Yes. If these notes and their repayment were a part of this rate case, I would have had questions about how the loan figures were arrived at, what was given in exchange for the notes and whether it is appropriate to have their cost included in the rate case.

Q12. HAVE THESE QUESTIONS BEEN RAISED ELSEWHERE IN THIS PRESENT RATE CASE?

A12. No. Any amounts required to begin the payment of these notes has not been included within the test period or attrition period of this rate case. Therefore the CAPD does not argue this point in this current case, but instead reserves judgment on this issue for any future rate cases which might include any payment on these notes.

IV. CAPD PROPOSED RATE DESIGN

Q13. MR. NOVAK, PLEASE EXPLAIN THE CAPD'S PROPOSED RATE DESIGN.

A13. As shown on CAPD Exhibit, Schedule 6, we have proposed a significant change to the Company's existing rate design. Instead of the current minimum bill and usage charge rate design, we are proposing a monthly customer charge along with a three tier usage charge.

Q14. WHY IS THE CAPD PROPOSING SUCH A CHANGE IN RATE DESIGN AT THIS TIME?

A14. In the Company's last rate case (Docket 09-00034) the CAPD originally proposed a three tiered usage charge. Unfortunately, in the previous case we were unable to obtain sufficient billing data that would allow us to propose specific rates for tiered usage. In this case, the CAPD was able to obtain the Company's monthly billing data for each customer from January 2008 through December 2011. This data allowed us to analyze the usage characteristics for all customers and to make a recommendation to the TRA on tiered customer usage.

Q15. PLEASE EXPLAIN THE CAPD'S PROPOSED RATE DESIGN STRUCTURE.

A15. As shown on CAPD Exhibit, Schedule 6, we are first proposing a $16.50 per month customer charge for all customer classes. Next we are proposing a three tiered usage charge for all customer classes representing the first 6,000 gallons consumed per month, the next 6,000 gallons consumed per month, and then all usage over 12,000 gallons per month. The usage charges that we are proposing for these three tiers are $5.00, $10.00 and $15.00 per 1,000 gallons respectively and increase as the customer's monthly consumption increases.

Q16. WHY IS THE CAPD PROPOSING TO ELIMINATE THE NON-RESIDENTIAL AND SPECIAL CONTRACT RATES?

A16. The Company only had a single non-residential customer with a minimum amount of usage making a separate tariff impractical. In addition, the current charges to the Company's special contract customer were less under the Company's existing tariff rates than under the special contract rate which made the special contract rate obsolete. Finally, combining all customer classes into a single tariff structure makes the rate schedule application much simpler to administer.

Q17. WHY ARE YOU PROPOSING THESE SPECIFIC USAGE TIERS?

A17 Our analysis of the individual customer usage revealed that 6,000 gallons per month represented the median usage for all customers. In other words, over the four year period in our study, approximately half of all the Company's customers used less than 6,000 gallons per month. In addition, our analysis showed that 6,000 gallons per month also represented one standard deviation from the median. We therefore chose to propose a three tier usage structure consisting of the first 6,000 gallons per month, the next 6,000 gallons per month and then a third tier for all usage over 12,000 gallons per month.

Q18. WHAT IS THE IMPACT OF THIS PROPOSED TARIFF CHANGE ON DIFFERENT CUSTOMER CLASSES?

A18. Naturally, the impact of any change in volumetric rates will be dependent upon each customer's consumption. As shown on CAPD Exhibit, Schedule 12, for customers using 6,000 gallons per month, which is the median consumption level for all customers, the billing increase under the CAPD's proposed rates will be less than 3%.

Small usage customers, those with consumption of less than 1,000 gallons per month, will see their bill increase from $15.00 to $21.50 or approximately 43%.

However, even this change will result in a decrease from the Company's unauthorized minimum bill charge of $25.00 which is presently in effect and discussed elsewhere in my testimony.

Large usage customers, those with consumption of 15,000 gallons or more per month, will see their bill increase by approximately 27%. The reason for this larger increase is due to the CAPD's proposed escalating rate block structure – rates increasing as monthly consumption increases. The CAPD feels that these larger usage customers are causing a disproportionate increase in costs to provide service. We have therefore designed a rate structure that attempts to match the revenues with those customers that are causing this cost increase. In addition, the CAPD's proposed rate design advances the TRA's policy goal of conservation mentioned in the Order of the Company's previous rate case.[3]

Q19. WHY ARE YOU PROPOSING THAT THE COMPANY INCLUDE A PROVISION FOR LATE PAYMENTS IN THEIR TARIFF?

A19. As shown on Item #7 of Attachment WHN-4, the Company currently has a contract with the City of Franklin that already includes a late payment charge. Under the Company's contract, the City of Franklin prorates any late charges received between the customer's water and sewer bill and then remits the sewer portion of the late payment charges to Berry's Chapel. The CAPD is recommending that the TRA now recognize this contract and its related impact in setting rates on a going forward basis.

[3] Docket 09-00034, dated November 3, 2009, Page 13.

V. BILLING ERRORS

Q20. HAS THE COMPANY CORRECTLY APPLIED THE RATES IN ITS EXISTING TARIFF SINCE THE LAST RATE CASE?

A20. No. The CAPD has found a number of instances where the Company has either voluntarily or involuntarily charged incorrect rates to its customers. Furthermore, the CAPD believes that the TRA needs to order the Company to refund these receipts back to the individual customers that paid them with interest.

Q21. IN WHAT AREAS HAS THE COMPANY MISCHARGED ITS CUSTOMER?

A21. The CAPD believes that the Company has over charged its customers by $160,521 since their last rate case through unauthorized changes to their tariff rates in the following instances.

- An over collection of $13,901 from charging an unauthorized late fee to customers without approval by the TRA.
- An over collection of $84,350 from an unauthorized billing increase of $20 and $30 per month for residential and non-residential customers respectively from December 2010 through April 2011 without approval by the TRA.
- An over collection of $5,030 from an unauthorized increase in the minimum bill from $15 to $25 beginning in December 2010 and still in effect today without approval by the TRA.

- An over collection of $45,397 from refusal to cease the $0.38 per 1,000 gallons odorization surcharge approved by the TRA in Docket 08-00060 for a twelve month period.
- An over collection of $11,843 from a $0.68 per 1,000 gallons surcharge incorrectly implemented by one of the Company's billing agents.

Q22. PLEASE EXPLAIN THE LATE FEE BILLING ERRORS CHARGED BY THE COMPANY.

A22. The Company's current billing contract with the City of Franklin and its previous contract with HB&TS provide for billing a late charge even though Lynwood does not have a provision for late charges in its tariff. Specifically, Paragraph 7 of the Company's billing contract with the City of Franklin reads as follows:

> "In the event a BCU sewer customer does not pay its sewer service charges when due, CITY agrees to enforce the collection of the sewer charges in the same manner as CITY enforces the collection of its water service charges. Such enforcement of collection shall include mailing of late notices, assessing late charges (or disallowing discounts) and, when appropriate, cutting off water service to that customer until such time as full payment is made by that customer."[4]

As a result of the language contained in its billing contracts, the Company has been able to circumvent its TRA approved tariff and apply late charges to customers without TRA authorization. As shown on CAPD Exhibit, Schedule 7, these late charges totaled over $13,900.51 for 2010 and 2011. It is the position of the CAPD that these unauthorized late fee charges need to be refunded back to the Company's customers with interest.

[4] A copy of this contract is included in Attachment WHN-4.

Q23. PLEASE EXPLAIN THE COMPANY'S SURCHARGE OF $20.00 AND $30.00 PER MONTH WITHOUT PRIOR APPROVAL BY THE TRA.

A23. In November 2010, the Company notified its billing agents that it was implementing a new $20 per month customer charge for residential customers and $30 per month for non-residential customers.[5] This charge was then implemented in December 2010 and ran through April 2011. As shown on CAPD Exhibit, Schedule 8 the financial impact of this unauthorized $20 and $30 surcharge totaled $84,350. It is the position of the CAPD that these unauthorized customer charges need to be refunded back to the Company's customers with interest.

Q24. PLEASE EXPLAIN THE COMPANY'S INCREASE IN THE MINIMUM BILL FROM $15 TO $25.

A24. Simultaneous with the Company's November 2010 notice to its billing agents of the new $20 and $30 customer charges described above, the Company also provided notice that it was increasing the customer's monthly minimum bill from $15 to $25. However, this unauthorized change in the minimum bill was never discontinued <u>and is in fact still being charged today</u>. As shown on CAPD Exhibit, Schedule 9, this unauthorized increase in the minimum bill has resulted in $5,030 in over charges to the Company's customers through December 2011. It is the position of the CAPD that these unauthorized minimum bill charges need to be refunded back to the Company's customers with interest.

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[5] A copy of this notice is included in Attachment WHN-2.

Q25. PLEASE EXPLAIN THE COMPANY'S FAILURE TO CEASE THE ODORIZATION SURCHARGE OF $0.38 PER 1,000 GALLONS.

A25. On April 29, 2009, the TRA approved a surcharge of $0.38 per 1,000 gallons in Docket 08-00060 to allow Lynwood to recover its deferred odor eliminations costs of $30,973.02. The language in the Commission's Order was very specific and only provided for the recovery of a fixed dollar amount for a limited period of time as shown below:

1. Lynwood will be allowed to recover $30,973.02 in deferred odor elimination costs over a twelve month period.
2. Based on the annual average of volumes of billed water for years 2005 – 2007, the average monthly surcharge per 1,000 gallons will be $0.38 for twelve months.
3. At the end of the authorized twelve month period, the Company will provide a full accounting to the TRA in a report filed in this docket disclosing how much was collected under the surcharge. The report will disclose whether the Company under or over collected. After consulting with appropriate TRA Staff and the Consumer Advocate, the Company will arrange for timely refunds for any over collection or be permitted to recover any balance of the $30,973.02 that was not recovered.

On June 1, 2009, Lynwood began applying the $0.38 per 1,000 gallon surcharge to their customers. However, the Order in this case specifically states that this surcharge was only to run for 12 months. As a result, the surcharge should have ceased in May 2010. Instead, the Company has continued this surcharge and <u>it is still being billed to customers today</u>. As shown on CAPD Exhibit, Schedule 10, this unauthorized surcharge has resulted in $45,697 in over charges to the Company's customers from June 2010 through December 2011. It is the position of the CAPD that these unauthorized odorization surcharges need to be refunded back to the Company's customers with interest.

Q26. PLEASE EXPLAIN THE $0.68 PER 1,000 GALLON SURCHARGE IMPLEMENTED BY THE CITY OF FRANKLIN.

A26. While analyzing the Company's billing summaries, the CAPD discovered that the City of Franklin had incorrectly implemented an incremental surcharge of $0.68 per 1,000 gallons from July 2009 through October 2009. When the CAPD asked the City of Franklin for the reasons for this change, we were ultimately told that no reason could be determined. A copy of the City of Franklin's response is included on Attachment WHN-3. As shown on CAPD Exhibit, Schedule 11, this $0.68 surcharge has resulted in $11,843 in unauthorized surcharges to the Company's customers. The CAPD has since learned that the City of Franklin intends to refund this surcharge back to the Company. It is the position of the CAPD that these unauthorized surcharges need to be refunded back to the Company's customers with interest.

Q27. DOES THIS COMPLETE YOUR TESTIMONY?

A27. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available.

ATTACHMENT WHN-1

William H. Novak Vitae

William H. Novak

19 Morning Arbor Place
The Woodlands, TX 77381

Phone: 713-298-1760
Email: halnovak@whnconsulting.com

Areas of Specialization

Over twenty-five years of experience in regulatory affairs and forecasting of financial information in the rate setting process for electric, gas, water and wastewater utilities. Presented testimony and analysis for state commissions on regulatory issues in four states and has presented testimony before the FERC on electric issues.

Relevant Experience

WHN Consulting – September 2004 to Present
In 2004, established WHN Consulting to provide utility consulting and expert testimony for energy and water utilities. Complete needs consultant to provide the regulatory and financial expertise that enabled a number of small gas and water utilities to obtain their Certificate of Public Convenience and Necessity (CCN) that included forecasting the utility investment and income. Also provided the complete analysis and testimony for utility rate cases including revenues, operating expenses, taxes, rate base, rate of return and rate design for utilities in Tennessee. Assisted American Water Works Company in preparing rate cases in Ohio and Iowa. Provided commercial and industrial tariff analysis and testimony for an industrial intervenor group in a large gas utility rate case. Industry spokesman for water utilities dealing with utility commission rulemaking. Consultant for the North Carolina and Illinois Public Utility Commissions in carrying out their oversight functions of Duke Energy and Peoples Gas Light and Coke Company through focused management audits. Also provide continual utility accounting services and preparation of utility commission annual reports for water and gas utilities.

Sequent Energy Management – February 2001 to July 2003
Vice-President of Regulatory Compliance for approximately two years with Sequent Energy Management, a gas trading and optimization affiliate of AGL Resources. In that capacity, directed the duties of the regulatory compliance department, and reviewed and analyzed all regulatory filings and controls to ensure compliance with federal and state regulatory guidelines. Engaged and oversaw the work of a number of regulatory consultants and attorneys in various states where Sequent has operations. Identified asset management opportunities and regulatory issues for Sequent in various states. Presented regulatory proposals and testimony to eliminate wholesale gas rate fluctuations through hedging of all wholesale gas purchases for utilities. Also prepared testimony to allow gas marketers to compete with utilities for the transportation of wholesale gas to industrial users.

<u>Atlanta Gas Light Company – April 1999 to February 2001</u>
Director of Rates and Regulatory Analysis for approximately two years with AGL Resources, a public utility holding company serving approximately 1.9 million customers in Georgia, Tennessee, and Virginia. In that capacity, was instrumental in leading Atlanta Gas Light Company through the most complete and comprehensive gas deregulation process in the country that involved terminating the utility's traditional gas recovery mechanism and instead allowing all 1.5 million AGL Resources customers in Georgia to choose their own gas marketer. Also responsible for all gas deregulation filings, as well as preparing and defending gas cost recovery and rate filings. Initiated a weather normalization adjustment in Virginia to track adjustments to company's revenues based on departures from normal weather. Analyzed the regulatory impacts of potential acquisition targets.

<u>Tennessee Regulatory Authority – Aug. 1982 to Apr 1999; Jul 2003 to Sep 2004</u>
Employed by the Tennessee Regulatory Authority (formerly the Tennessee Public Service Commission) for approximately 19 years, culminating as Chief of the Energy and Water Division. Responsible for directing the division's compliance and rate setting process for all gas, electric, and water utilities. Either presented analysis and testimony or advised the Commissioners/Directors on policy setting issues, including utility rate cases, electric and gas deregulation, gas cost recovery, weather normalization recovery, and various accounting related issues. Responsible for leading and supervising the purchased gas adjustment (PGA) and gas cost recovery calculation for all gas utilities. Responsible for overseeing the work of all energy and water consultants hired by the TRA for management audits of gas, electric and water utilities. Implemented a weather normalization process for water utilities that was adopted by the Commission and adopted by American Water Works Company in regulatory proceedings outside of Tennessee.

Education

B.A, Accounting, Middle Tennessee State University, 1981
MBA, Middle Tennessee State University, 1997

Professional

Certified Public Accountant (CPA), Tennessee Certificate # 7388
Certified Management Accountant (CMA), Certificate # 7880
Former Vice-Chairman of National Association of Regulatory Utility Commission's Subcommittee on Natural Gas

ATTACHMENT WHN-2

Company Notice to Billing Agents of Unauthorized Rate Changes

Copy to T.P

BERRY'S CHAPEL UTILITY, INC.
321 BILLINGSLY COURT, SUITE 4
FRANKLIN, TN 37067
PHONE: 615/790-3632 FAX: 615/599-0797

Copy for Tom's Notes

RECEIVED
NOV 19 2010
HB & TS
UTILITY DIST

November 15, 2010

HB & TS UTILITY DISTRICT
505 Downs Blvd.
Franklin, TN 37064
Attn: Tom Puckett

Re: Change in Rates

Based on our rate study, as of September 1, 2010, our rates are not producing enough revenue to meet the requirements as set forth in our TDEC permit.

Effective November 1, 2010, the Board has approved rates that will include a facility charge of $20.00 per month for each residential customer. Please arrange to have this charge included in the bills rendered based on your November meter readings. There will be no change in the volume rates of $8.35. We will mail a notice of the rate changes to each customer. A copy of this notice is attached for your information.

I appreciate your assistance in making this rate change. If you have any questions related to the above please call me at 615/790-3632 and leave a message and we will get back to you as soon as possible.

Sincerely yours,

Tyler Ring
President

2010 change

COPY MAR 08 2012

To Hal Novak

BERRY'S CHAPEL UTILITY, INC.

MONTHLY SEWER SERVICE BILLING

RESIDENTIAL, CONDOMINIUM, HOUSE OR APARTMENT

Charge per 1,000 gallons

(Actual or assumed flow) $8.35

Minimum Monthly Charge .... $\boxed{\$25.00}$ 3 Current Min is $15.

Facilities Charge $20.00 2

NON-RESIDENTIAL

Charge per 1,000 gallons

(Actual or Assumed Flow) $10.34

Minimum Monthly Charge $30.00

Facilities Charge $30.00

TAP FEES

RESIDENTIAL $3,500.00

NON-RESIDENTIAL

Charge per gallon per day
(Computed by multiplying the peak monthly
Usage during the first year by 12 divided
By 365 days.) $7.86

SEWER CONNECTION FEES

RESIDENTIAL OR NON-RESIDENTIAL $250.00

GENERAL FEES

Returned Check Charge $30.00

2010 change

Issue Date:	November 1, 2010
Effective Date:	November 1, 2010

COPY

To Hal Novak

Tom's Notes Copy

BERRY'S CHAPEL UTILITY, INC.
321 BILLINGSLY COURT, SUITE 4
FRANKLIN, TN 37067
PHONE: 615/790-3632 FAX: 615/599-0797

November 15, 2010

CITY OF FRANKLIN
109 3rd Ave.
Franklin, TN 37064
Attn: Steve Simms

Re: Change in Rates

Based on our rate study, as of September 1, 2010, our rates are not producing enough revenue to meet the requirements as set forth in our TDEC permit.

Effective November 1, 2010, the Board has approved rates that will include a facility charge of $20.00 per month for each residential customer. Please arrange to have this charge included in the bills rendered based on your November meter readings. There will be no change in the volume rates of $8.35. We will mail a notice of the rate changes to each customer. A copy of this notice is attached for your information.

I appreciate your assistance in making this rate change. If you have any questions related to the above please call me at 615/790-3632 and leave a message and we will get back to you as soon as possible.

Sincerely yours,

Pres.

Tyler Ring
President

BERRY'S CHAPEL UTILITY, INC.
RATE CHANGE NOTICE

Based on our rate study as of September 1, 2010, we are not producing enough revenue to meet the requirements as set forth in our TDEC permit. This, along with the repairs and replacement required by the flood damages to the Treatment Plant not covered by our National Flood Insurance Plan will require an increase in our annual revenues.

Effective November 1, 2010, our rates will be adjusted by a $20.00 per month facility charge to each customer. The volume rates will not be changed and will remain at $8.35 per 1000 gallons of water consumed by residential customers. This charge will appear on the bill that customers receive in December, 2010. Questions related to this matter may be made to 615/790-3632 or faxed to 615/599-0797.

BERRY'S CHAPEL UTILITY, INC.

MONTHLY SEWER SERVICE BILLING

RESIDENTIAL, CONDOMINIUM, HOUSE OR APARTMENT

Charge per 1,000 gallons

(Actual or assumed flow)	$8.35
Minimum Monthly Charge	$25.00
Facilities Charge	$20.00

NON-RESIDENTIAL

Charge per 1,000 gallons

(Actual or Assumed Flow)	$10.34
Minimum Monthly Charge	$30.00
Facilities Charge	$30.00

TAP FEES

RESIDENTIAL	$3,500.00

NON-RESIDENTIAL
Charge per gallon per day
(Computed by multiplying the peak monthly
Usage during the first year by 12 divided
By 365 days.) $7.86

SEWER CONNECTION FEES

RESIDENTIAL OR NON-RESIDENTIAL	$250.00

GENERAL FEES

Returned Check Charge	$30.00

Issue Date: November 1, 2010
Effective Date: November 1, 2010

received
4-25-11

BERRY'S CHAPEL UTILITY, INC.
321 BILLINGSLY COURT, SUITE 4
FRANKLIN, TN 37067
PHONE: 615/790-3632 FAX: 615/599-0797

April 25, 2011

City of Franklin
109 Third Avenue South
Franklin, TN 37064
Attn: Steve Simms

Dear Steve,

The Board of Directors of Berry's Chapel Utility, Inc. has voted to suspend charging its monthly facilities charge of $20.00 until further notice beginning with the bills rendered by you in May. Please let me know of any additional information you may need to make this change in your billing program. Berry's Chapel Utility, Inc. appreciates the billing and collection services you provide for its sewer customers which are served water by the City of Franklin.

Sincerely,

Pres.

Tyler Ring, President

cc: Don Scholes

ATTACHMENT WHN-3

Acknowledgment of Billing Error by the City of Franklin

- # Berry Chapel Rate

3/26/12

Christy McCandless

To Hal Novak

From: **Christy McCandless** (CHRISTYM@franklintn.gov)

Sent: Mon 3/26/12 2:32 PM

To: Hal Novak (halnovak@whnconsulting.com)

Mr. Novak, in response to the question that you had regarding the spread sheet for the time frame of June-Sept. 2009 being off on the rate. After consulting with the previous manager and some addition research, we are unable to determine how the rate was different for that 4 month period.

ATTACHMENT WHN-4

Billing Contract with the City of Franklin

COF Contract Number 2011-011 COPY

AGREEMENT BETWEEN
THE CITY OF FRANKLIN, TN AND BERRY'S CHAPEL UTILITY, INC.
FOR THE COLLECTION OF SEWER SERVICE CHARGES

This Agreement is made this the 12th day of April, 2011, by and between Berry's Chapel Utility, Inc., hereinafter called "BCU" and the City of Franklin, Tennessee, hereinafter called "CITY", which in consideration of mutual promises and covenants made herein, agree as follows:

WHEREAS, CITY entered into a contract with Lynwood Utility Company, Inc. dated December 14, 1999 as amended June 19, 2007, to bill and collect Lynwood's sewer service charges from Lynwood's customers who also receive water service from the City, and

WHEREAS, Lynwood merged with Berry's Chapel Utility, Inc. with Berry's Chapel Utility, Inc being the surviving corporation; and

WHEREAS, CITY and BCU wish to continue the relationship previously established by CITY and Lynwood.

NOW THEREFORE, in light of the recitals, which are incorporated herein by reference, and the promises herein contained that CITY and BCU, in consideration of the premises and of the mutual covenants herein set forth, do mutually agree as follows:

1. BCU operates a Central Sewerage and wastewater collection system within an area in which CITY provides water service. BCU has requested and CITY has agreed to bill and collect sewer service charges for BCU from its customers who receive water service from CITY.

2. BCU will provide its sewer service rate schedule to CITY in writing, as amended from time to time, thirty (30) days in advance of its effective date to allow CITY time to modify its computer billing system.

3. CITY will supply to BCU any changes to CITY's billing policies or related fees that would affect BCU's sewer customers sixty (60) days in advance of the effective date to allow BCU time to modify its rules and regulations and fees and charges, if necessary.

4. Upon request, CITY will provide to BCU a listing of BCU's customers who receive water service from CITY, together with each customer's monthly water consumption, for purposes of establishing and monitoring BCU's sewer service rates.

5. BCU's sewer service rate schedule shall in all cases be multiplied by the quantity of water billed by CITY in the current billing cycle for water service, inclusive of any meter adjustments or other adjustments for current or prior billing cycles, consistent with CITY's normal policies and procedures for such adjustments, and exclusive of any sales taxes on such water service. Water provided by the City through a separately metered "irrigation" meter is excluded for purposes of applying the sewer service charge. CITY shall compute and bill to each of BCU's sewer customers for the resulting sewer service charge.

6. CITY will render combined statements for its water service charges and BCU's sewer service charges in accordance with CITY's normal billing cycle(s). CITY will cause to be printed on its billing statement the name, address and telephone number of the BCU office and BCU's sewer

customers will be instructed to contact BCU directly concerning complaints and maintenance of the sewer system.

7. In the event a BCU sewer customer does not pay its sewer service charges when due, CITY agrees to enforce the collection of the sewer charges in the same manner as CITY enforces the collection of its water service charges. Such enforcement of collection shall include mailing of late notices, assessing late charges (or disallowing discounts) and, when appropriate, cutting off water service to that customer until such time as full payment is made by that customer. CITY shall be entitled to retain one hundred (100%) of all water cut off and reconnection charges assessed and collected from BCU's sewer customers as a result of non-payment or other breach of contract.

8. On or before the twentieth (20th) day of each month, CITY will deliver to BCU the gross amount CITY has collected from BCU's sewer customers for BCU sewer services through the last day of the previous month, less a service fee equal to seven and one-half percent (7.5%) of the gross amount collected, which sum shall be retained as the sole and separate property of CITY for providing the services agreed upon in this Agreement.

9. CITY will provide to BCU with its monthly remittance one or more monthly reports which show for each BCU customer the customer's account number, the customer's name, the service address and the amounts billed and/or collected on behalf of BCU for sewer service charges. The totals per this report(s) shall equal the gross amount due BCU in accordance with this contract. It shall be the responsibility of BCU to reconcile the monthly report to its records and to notify CITY of any billing discrepancies discovered on a timely basis.

10. BCU shall pay to CITY the full cost for setup and programming of CITY's billing system necessary to implement this agreement.

11. CITY will refer to BCU any inquiries regarding new sewer service in BCU's area of service. BCU will determine if a new sewer customer will be accepted for connection to its sewer and wastewater collection system. If accepted, BCU will collect the appropriate sewer tap fees, connection fees and/or inspection fees and will provide the new sewer customer with a receipt and authorization form.

12. CITY and BCU may establish a combined application and contract form for water and sewer service. CITY may accept applications and contracts on behalf of BCU for any transfers of existing sewer service. CITY may accept applications and contracts for new sewer service only upon presentation of a valid receipt and authorization form for new sewer service. CITY shall maintain in its files copies of all such applications and contracts for new & transferring customers. Upon termination of this contract, or upon request from time to time by BCU, CITY will supply BCU with copies of such applications and contracts. CITY shall retain one hundred percent (100%) of its application & connection fees for new & transferring customers.

13. CITY shall have no duty to repair or maintain any portion of BCU's sewer system except by separate agreement between the parties.

14. The parties agree to cooperate fully in exchanging information and implementing procedures to fully implement the intent of this contract. BCU shall have access to the books of CITY concerning the administration of this contract from time to time as BCU sees fit upon reasonable notice to CITY of its intent to do so.

15. Before CITY incorporates BCU'S sewer service rates, rules and regulations in its billing as contemplated herein, BCU shall obtain the approval of the Tennessee Regulatory Authority ("TRA") of a revised tariff incorporating such rates, rules and regulations and shall notify CITY in writing upon receipt of such approval provided BCU is subject to regulation by the TRA.

16. If BCU is subject to regulation by the TRA, and in the event CITY receives an order and notice from the TRA that the Authority has suspended or revoked BCU's certificate of public convenience and necessity to operate sewer utility pursuant to Authority Rule 1220-4-13-.09, CITY shall withhold administrative fees and charges authorized by this Agreement, then pay all remaining sewer service charges collected for BCU after the receipt of the order and notice to the TRA, a court appointed receiver or other entity or person whom the TRA directs which entity or person shall be responsible for continuing the operation of BCU's sewer system.

17. BCU shall indemnify and hold harmless CITY from and against any and all claims related to the CITY'S obligation to pay sewer charges to the TRA, a court appointed receiver or other entity or person to whom the TRA directs which entity or person shall be responsible for continuing the operation of BCU'S sewer system.

18. This Agreement may be terminated by either party by the giving of ninety (90) days written notice to the other party.

WITNESS the execution hereof this day and date first above written.

BERRYS CHAPEL UTILITY, INC.

By: [signature] Pres.
Tyler L. Ring
President

CITY OF FRANKLIN, TENNESSEE

By: [signature]
Dr. Ken Moore
Mayor
109 3rd Avenue South
Franklin, TN 37064

ATTEST:

By: Eric S. Stuckey
Eric Stuckey
City Administrator

Approved as to form:

By: Shauna R. Billingsley
Shauna R. Billingsley
City Attorney

LAW DEPARTMENT

Shauna R. Billingsley, Esq.
City Attorney
Also Licensed in Texas

HISTORIC
FRANKLIN
TENNESSEE

April 18, 2011

VIA REGULAR MAIL

Donald L. Scholes
Branstetter, Stranch & Jennings, PLLC
227 Second Avenue North
Fourth Floor
Nashville, Tennessee 37201-1631

Re: ***Agreement between the City of Franklin, TN and Berry's Chapel Utility, Inc. for the Collection of Sewer Service Charges***

Dear Mr. Scholes,

Please find enclosed the fully executed original regarding the above referenced agreement. Should you need anything further or have any questions, please do not hesitate to contact us.

Yours truly,

J. Samuel Cross

Sam Cross
Paralegal

Enclosure

ATTACHMENT

8

GAS UTILITIES DOCKET NO. 9902

STATEMENT OF THE INTENT OF CENTERPOINT ENERGY RESOURCES CORP., D/B/A CENTERPOINT ENERGY ENTEX AND CENTERPOINT ENERGY TEXAS GAS TO INCREASE RATES ON A DIVISION WIDE BASIS IN THE HOUSTON DIVISION	§ § § § § §	BEFORE THE RAILROAD COMMISSION OF TEXAS

DIRECT TESTIMONY OF

WILLIAM H. NOVAK

ON BEHALF OF

THE STATE OF TEXAS

October 19, 2009

DIRECT TESTIMONY OF WILLIAM H. NOVAK
GUD NO. 9902
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ATTACHMENTS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD, PLEASE.

A. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a CPA firm that also provides utility consulting and expert witness services.

Q. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am licensed to practice as a Certified Public Accountant (CPA) and am also a Certified Management Accountant (CMA).

My work experience has centered on regulated utilities for over 25 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee, where I was responsible for defending the utility's gas cost recovery and rate filings at a time when it was completely exiting the gas merchant function in Georgia. I also served for two years as the Vice President of Regulatory Compliance for Sequent Energy Management, a natural gas trading and optimization company in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the State of Texas ("the State").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony will address the following issues raised by CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas ("CenterPoint's" or "the Company's") filing:

- The proposed Cost of Service Adjustment (COSA);
- The proposed Pension Cost Recovery (PCR) adjustment;
- The proposed Integrity Assessment & Management (IAM) adjustment;
- The proposed changes to the Purchased Gas Adjustment (PGA); and
- The methodology used by the Company to calculate its Class Cost of Service Study.

Q. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A. I have reviewed the Company's Statement of Intent, along with the testimony and exhibits presented with their filing. In addition, I have reviewed the Company's workpapers related to the cost of service and revenue calculation supporting their filings. I have also reviewed the Company's responses to the relevant data requests submitted by the intervening parties and the Examiner.

I. COST OF SERVICE ADJUSTMENT

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED COST OF SERVICE ADJUSTMENT?

A. Yes. The proposed Cost of Service Adjustment ("COSA") allows the Company to implement new rates on an annual basis without going through the normal rate case process. This is the first of several mechanisms that the Company has proposed in order to reduce its risk as a gas utility.

Q. WHAT IS THE COMPANY'S RATIONALE FOR REQUESTING THE COSA?

A. The Company claims that it is expecting to experience changing levels of expense over the next several years, and that in order to minimize its regulatory expense it has filed this COSA tariff to allow it to adjust its rates to the cost of service that is actually experienced.[1]

Q. DOES THE GAS UTILITY REGULATORY ACT ("GURA") CONTEMPLATE AN AUTOMATIC RATE ADJUSTMENT SUCH AS COSA?

A. No. GURA Chapter 104, "Rates and Services," addresses rate changes initiated by a gas utility in Subchapters C and G. In Subchapter C, entitled "Rate Changes Proposed by a Utility," a rate change is authorized subject to a formal statement of intent rate case that includes a comprehensive cost of service rate review. In Subchapter G, entitled "Interim Rate Adjustment," an interim rate change is authorized through the Gas Reliability Infrastructure Project ("GRIP") Statute to recover the cost of changes for investment in service. Because the COSA proposed by the Company in this proceeding satisfies neither of these two provisions, it cannot be considered as a methodology required by GURA for a change in rates. The COSA proposed by the Company is neither an Interim Rate Adjustment per Subchapter G nor the result of a formal statement of intent per Subchapter C.

Q. HOW WILL THE PROPOSED COSA TARIFF BE IMPLEMENTED?

A. According to the Company's proposed COSA Tariff,[2] the Company will make an annual filing with the Commission no later than May 1st. The Commission will

[1] Direct testimony of Richard Zapalac, Page 11, Lines 3-12.

then have 90 days to review the Company's filing before rates go into effect on August 1st. If the Commission disagrees with the Company's filing, then the Company has the right to appeal this decision and place new COSA rates into effect subject to refund.

Q. IS THE PROPOSED COSA TARIFF IN THIS CASE THE SAME AS THAT ALREADY APPROVED FOR THE TEXAS COAST DIVISION?

A. No. The Texas Coast COSA (COSA-3) specifically limits the annual COSA surcharge to five percent (5%) of the customer charge. In this proceeding, there is no cap on the annual COSA surcharge. In addition, the Texas Coast COSA provides for total funding of $250,000 to assist with the annual regulatory rate review of COSA. In this proceeding, the funding for the annual regulatory rate review of COSA is limited to $100,000.

Q. WHAT IS THE IMPACT FROM THE REMOVAL OF THE 5% ANNUAL COSA SURCHARGE CAP?

A. Removal of the 5% annual COSA surcharge cap could potentially end all future rate cases, since the COSA would allow recovery on an annual basis of all costs without a rate case filing or a hearing to set rates. It would also eliminate customer participation through the intervention process, since rate cases would be

[2] Exhibit A to the Company's Statement of Intent, Page 10.

eliminated, and intervenors are apparently not encouraged to participate in the annual COSA review.

Q. ***BUT WOULDN'T THE COSA ALSO ELIMINATE THE COMPANY'S RATE CASE COSTS WITH THIS SAVINGS PASSED ON TO CUSTOMERS?***

A. Certainly. Since rate cases would now be replaced with an annual automatic adjustment mechanism, the Company would not incur any rate case costs. However, as a regulatory enticement, the Company has proposed to reimburse its regulators up to $100,000 for their annual costs to investigate COSA. Since this "regulatory candy" ultimately increases the COSA surcharge, it is unclear what the net impact would be on the Company's rate case costs.

Q. ***DO YOU AGREE WITH THE COMPANY'S REQUEST FOR THE COSA?***

A. No. The COSA represents an attempt by the Company to minimize regulatory oversight and to reduce its rate recovery risk. In addition, the Company has offered no proof in its filing that the cause for this tariff is material and its timing is imminent. Instead, we are only told through testimony that Company is "anticipating significant cost increases."[3] However, nothing is mentioned by the Company of any expected costs decreases that may either mitigate or offset any increase to its future cost of service.

Q. WHAT IS THE COMPANY'S RECOURSE IF IT DOES EXPERIENCE AN INCREASE TO ITS COST OF SERVICE?

A. The Company is certainly free to file a new rate case anytime that it feels it is justified. While a tariff such as the COSA may well reduce future rate case expenses through the use of automatic adjustment clauses, it also degrades the ability of regulatory authorities to properly review all other aspects of the Company's filings including any concerns that are raised by intervenors. In addition, automatic adjustment clauses such as the COSA can encourage wasteful and imprudent spending since these costs are automatically recovered from customers without the same scrutiny that takes place during a formal rate case.

Q. YOU MENTIONED THAT THE COSA WAS AN ATTEMPT BY THE COMPANY TO REDUCE ITS RISK WITHOUT A CORRESPONDING ADJUSTMENT TO ITS EQUITY RETURN. WHAT WOULD BE THE APPROPRIATE RETURN ON EQUITY FOR A GAS UTILITY WITH A COSA SIMILAR TO WHAT HAS BEEN PROPOSED HERE?

A. I'm not a cost of capital witness, and I'll certainly defer to the State's expert witness in this area. However, since the Company has proposed to reduce most of its revenue recovery risk through an automatic adjustment clause like COSA without a cap to limit its impact, it appears to me that the return on equity should be substantially reduced if the Company's proposed COSA is adopted.

---

[3] Direct testimony of Richard Zapalac, Page 11, Line 6.

Q. ***WHAT IS YOUR FINAL RECOMMENDATION ON THE COMPANY'S PROPOSED COSA?***

A. I recommend that the Company's proposed COSA be rejected and that the cost of service continue to be reviewed and considered only within the structure of a properly filed rate case as required by GURA.

II. PENSION COST RECOVERY ADJUSTMENT & INTEGRITY ASSESSMENT AND MANAGEMENT ADJUSTMENT

Q. ***HAVE YOU REVIEWED THE COMPANY'S PROPOSED PENSION COST RECOVERY ADJUSTMENT & INTEGRITY ASSESSMENT AND MANAGEMENT ADJUSTMENT MECHANISMS?***

A. Yes. The Company has proposed these two adjustments as an alternative if the Commission chooses to reject its proposed COSA. The Company's proposed Pension Cost Recovery ("PCR") Adjustment Rate Schedule allows for an annual adjustment to the Company's tariff rates for its most current pension expense. The Company's proposed Integrity Assessment and Management ("IAM") Adjustment Rate Schedule allows for an annual adjustment to the Company's tariff rates for recovery of its most current costs incurred from changes to existing rules and regulations by a regulatory body.[4]

Q. WHAT IS THE COMPANY'S RATIONALE FOR REQUESTING THE PCR AND IAM?

A. The Company claims that it is expecting to experience changing levels of expense in this area over the next several years, and that in order to minimize its regulatory expense it has filed this tariff to allow it to annually reset its rates to recover the cost that is actually experienced.[5]

Q. DO YOU AGREE WITH THE COMPANY'S REQUEST FOR THE PCR AND IAM?

A. No. Like the COSA, the PCR and IAM represent attempts by the Company to reduce its revenue recovery risk. In addition, the Company has offered no proof in its filing that the reasons for these two tariffs are material and their timing is imminent. Instead, we are only told through testimony that the Company is "expecting" changes to its cost in these two areas. However, nothing is mentioned by the Company of any expected cost decreases that may either mitigate or offset these expected increases.

[4] Company's Statement of Intent, Exhibit A, Pages 18 and 19.
[5] Direct testimony of Matthew Troxle, Page 18, Lines 6-13.

Q. WHAT IS THE COMPANY'S RECOURSE IF IT DOES EXPERIENCE THE INCREASE TO PENSION EXPENSE AND INTEGRITY ASSESSMENT AND MANAGEMENT COSTS THAT IT EXPECTS?

A. The Company is certainly free to file a new rate case anytime that it feels it is necessary. While a tariff such as the PCR and IAM may well reduce future rate case expenses through the use of automatic adjustment clauses, it also degrades the ability of regulatory bodies to properly review all other aspects of the Company's filing including new concerns that are voiced by customers. In addition, automatic adjustment clauses such as the PCR and IAM can encourage wasteful and imprudent spending since these costs are automatically recovered from customers, without the scrutiny that takes place during a formal rate case.

Q. DO YOU HAVE ANY FURTHER COMMENTS WITH RESPECT TO THE PCR AND IAM ADJUSTMENTS?

A. Yes. A review of the Company's proposed PCR tariff[6] reveals that only the Railroad Commission Staff is allowed to dispute or question the calculation of the Company's annual PCR filing. This provision eliminates all intervenors, including the State, from reviewing or commenting on the Company's PCR adjustment. I strongly disagree with this provision since the intervenors currently have the right to dispute pension expense within the structure of a rate case.

[6] Exhibit A to the Company's Statement of Intent, Page 19.

Likewise, an examination of the Company's proposed IAM tariff[7] reveals that there is no process contemplated for the review of the Company's annual IAM filing by either the regulatory authorities or intervenors. Therefore, as presently written, the IAM tariff allows new rates to go into effect without review or notice to customers. In addition, the proposed tariff does not specify how disputes regarding recorded costs are to be resolved. I strongly disagree with this provision of the IAM since all tariff filings should undergo adequate review by the regulatory authority and allow for the opportunity to intervene and comment by interested parties.

Q. WHAT IS YOUR FINAL RECOMMENDATION ON THE COMPANY'S PROPOSED PCR AND IAM ADJUSTMENTS?

A. I recommend that the Company's proposed PCR and IAM be rejected and that the Company's pension expense and regulatory costs continue to be reviewed and considered only within the structure of a properly filed rate case as required by GURA.

III. PURCHASED GAS ADJUSTMENT CHANGES

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED CHANGES TO ITS PURCHASED GAS ADJUSTMENT?

[7] Exhibit A to the Company's Statement of Intent, Page 18.

A. Yes. The Company has proposed two separate modifications to its current PGA rate schedule. The first modification would allow the Company to pass through the carrying charges on any changes to gas inventory via the PGA. The second modification would allow the Company to pass through the gas cost portion of uncollectible expense via the PGA.

Q. ***WHAT IS THE COMPANY'S RATIONALE FOR REQUESTING THESE CHANGES TO THE PGA?***

A. The Company claims that the volatility of wholesale gas cost has made the recovery of uncollected gas cost through base rates "inefficient and less accurate."[8] The Company provided no testimony supporting its proposed change to the PGA for recovering the carrying cost of gas in storage.

Q. ***DO YOU AGREE WITH THE COMPANY'S PROPOSED CHANGES TO ITS PGA RATE SCHEDULE?***

A. No. Like the COSA, PCR and IAM proposed changes discussed earlier, the proposed changes to the PGA rate schedule represent further attempts by the Company to reduce its business risk without a corresponding adjustment to its return on equity. In addition, the Company has offered no proof in its filing that its reason for the change to the PGA rate schedules are material and their timing is imminent.

Q. ***DO YOU HAVE ANY FURTHER COMMENTS WITH RESPECT TO THE COMPANY'S PROPOSED CHANGES TO ITS PGA RATE SCHEDULE?***

A. Yes. The changes sought by the Company to its PGA Rate Schedule involve policy issues that may need to be considered in a separate rulemaking docket for all regulated gas utilities outside of a rate case. Implementation of the PGA should be industry wide and not just apply to a single company as is being proposed here. Whether the carrying costs of gas storage inventory should be recovered through base rates or through the PGA is a question of industry-wide interest and impact that is best answered outside of this rate case.

In addition, the Company has not yet proven that it has the ability to provide the adequate reporting necessary for regulatory authorities to properly segregate its gas costs from each of its uncollectible accounts. Currently, these amounts are only reported in total along with the base rate portion of uncollectible expense. To segregate the accurate gas cost from each uncollectible account requires the ability to accurately identify the PGA rate that was applied on a cycle basis to each customer for multiple billing periods. In addition, provisions need to be made to flow subsequent customer payments back into the PGA when these amounts are collected. Until the Company can adequately demonstrate its ability to properly segregate, account for, and report these components of uncollected PGA costs, then any request to flow these costs through the PGA should be denied.

---

[8] Direct testimony of Matthew Troxle, Page 16, Line 23.

Q. WHAT IS YOUR FINAL RECOMMENDATION ON THE COMPANY'S PROPOSED CHANGES TO ITS PGA RATE SCHEDULE?

A. I recommend that the Company's proposed PGA Rate Schedule changes be rejected.

IV. COST OF SERVICE STUDY

Q. HAVE YOU REVIEWED THE COMPANY'S COST OF SERVICE STUDY?

A. Yes. I agree in principle with the methodology utilized by the Company to complete their Cost of Service Study. Based upon my review, the Company's Cost of Service Study did not appear to favor any particular customer group.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available. In addition, to the extent that I have not addressed a particular issue, method, procedure, etc. it should not be assumed that I am in agreement with the Company's treatment of that item.

ATTACHMENT

9

BEFORE
THE NORTH CAROLINA UTILITIES COMMISSION

Application of Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	
27511, for Authority to Increase Rates for	)	Docket No. W-218, SUB 319
Water and Sewer Utility Service in All of Its	)	
Service Areas in North Carolina	)	

PREFILED DIRECT TESTIMONY
of
WILLIAM H. NOVAK

ON BEHALF OF

PSS LEGAL FUND, INC.

May 25, 2011

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EXHIBITS

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. A detailed description of my educational and professional background is provided in Exhibit WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am a Certified Management Accountant, and am also licensed to practice as a Certified Public Accountant.

My work experience has centered on regulated utilities for over 25 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia, Virginia and Tennessee. I also served for two years as the Vice President of

Regulatory Compliance for Sequent Energy Management, a natural gas trading and optimization entity in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am testifying on behalf of PSS Legal Fund, Inc. ("PSS"). PSS was organized for the purpose of advocating for fair water and sewer rates primarily on behalf of the residents of the Park South Station subdivision located in Charlotte, North Carolina ("Park South Station").

Q4. HAVE YOU PRESENTED TESTIMONY IN ANY PREVIOUS RATE CASES BEFORE THIS COMMISSION?

A4. No. However, I have presented testimony in numerous rate cases before other public utility commissions including Tennessee, Texas and Ohio. In addition, I have conducted a number of rate and management audits on behalf of public utility commissions, including the NCUC, in dockets where I did not testify.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A5. My testimony will support and address PSS's positions and concerns with respect to the Company's Application. Specifically, I will address the following:

i. The failure of Aqua's proposal to provide just and reasonable rates for Park South Station due to the lack of an acquisition adjustment for the net costs of the water and sewer system as originally installed by the developer of Park South Station; and

ii. PSS's proposed rate design for residents of Park South Station taking into account costs of the water and sewer system already paid by residents of Park South Station.

Q6. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A6. I have reviewed the Company's Rate Case Application as filed on January 21, 2011, along with the testimony and exhibits filed on April 25, 2011. In addition, I have reviewed the Commission's Order in Docket No. W-274, SUB 653 approving the Application by Heater Utilities to provide water and wastewater service in Park South Station. Finally, I have reviewed the Company's and Public Staff's responses to the data requests submitted by PSS.

I. <u>ACQUISITION ADJUSTMENT</u>

Q7. PLEASE DESCRIBE THE WATER AND WASTEWATER SERVICE THAT RESIDENTS OF PARK SOUTH STATION CURRENTLY RECEIVE FROM AQUA.

A7 The area of Park South Station ("the Subdivision") consists of 853 lots of which approximately 25% have already been sold and are provided with utility service by Aqua. The Subdivision has an interconnection to the Charlotte Mecklenburg Utilities ("CMU"). CMU actually provides all of the water and wastewater services for the Subdivision subject to separate bulk water and wastewater agreements.

On December 18, 2007, the Commission issued its Order in Docket W-274, SUB 653 granting Aqua a Certificate of Public Convenience and Necessity allowing Aqua to provide water and wastewater utility service to Park South Station. Aqua acquired the Park South Station water and wastewater plant pursuant to a contract with J & B Development and Management ("J&B"), the developer of Park South Station. Under the terms of the contract, Aqua is to pay J&B $1,200 per lot for the water system as the lots are sold ($1,023,600 when fully built-out), and $0 for the wastewater system. Aqua is then permitted under its tariff to charge a $700 one-time connection charge to each new customer in the Subdivision. Through January 31, 2011, Aqua has recorded the following amounts in its ledger for the acquisition of Park South Station:[1]

	Water	Sewer	Total
Engineering	$39,000	$31,000	$70,000
Mains	315,837	492,992	808,829
Services	111,300	169,000	280,300
Pump Station	0	175,000	175,000
Total Plant	**$466,137**	**$867,992**	**$1,334,129**
			1,334,129

[1] Company response to PSS Data Request; Journal Entries N-44, N-51 and N-55.

Purchase Price	**$560,400**	**$0**	**$560,400**
Cont. in Aid of Const.	**$94,263**	**$0**	**$94,263**

In my opinion, Aqua also needs to include an acquisition adjustment in its ledger to fairly and accurately reflect the plant cost it should be allowed to recover through rates from its customers. As explained below, Aqua did not account for payments for the plant by the purchasers of lots in Park South Station.

Q8. PLEASE EXPLAIN THE PURPOSE OF AN ACQUISITION ADJUSTMENT.

A8. As a general rule, most public utility commissions limit the acquisition of utility plant from another entity to the <u>original cost incurred by the first owner devoting the property to public service</u>. Therefore, if a utility acquires major fixed assets (i.e., an operating unit or system) from another entity at a price in excess of the seller's original cost (***net of accumulated depreciation and contributions in aid of construction***), the addition to the acquiring utility's rate base reflecting the acquired assets is limited to the original net purchase price. The excess amount paid is referred to as an acquisition adjustment, and is generally treated as a reduction to rate base.

The necessity of this separate accounting treatment is largely a consequence of certain abuses in the utility industry during the acquisition and merger period of the 1920s and 1930s. Through the process of acquiring utility assets or entire utility companies at prices in excess of depreciated cost, purchasing utilities were able to write up their basis in plant assets. If these purchase prices were in excess of the "value" of the property, then the utility was able to inflate its rate base artificially.

The outgrowth of this situation was a general consensus among regulators that utility customers should not be required to pay for plant in service in excess of the historical net cost that existed when the property was originally devoted to public service, since any excess represented only a change in ownership without any increase in the service function to utility customers. Acquisition adjustments are therefore usually excluded from rate base and amortized below-the-line under the premise that these excess costs provide no additional benefit to customers and that to allow these investment dollars to earn a return or to allow recovery through cost of service treatment would unjustly penalize consumers.

Q9. IS AN ACQUISITION ADJUSTMENT APPROPRIATE IN THIS CASE?

A9. It most certainly is in the case of the residents of Park South Station. These customers originally paid for the entire water and wastewater system when they first purchased their lots and homes, as such costs are typically passed on by a developer to the purchasers of lots and homes. According to the NARUC Uniform System of Accounts, the cost of acquired utility plant is to be recorded on in the following manner:

> Any balance (representing the difference between the net original cost of the assets acquired and the cost to the acquiring utility) shall be charged or credited to account 114 – Utility Plant

> Acquisition Adjustment. When an existing water system or operating unit is acquired, the utility shall be obligated to obtain from the vendor all existing records, including records of plant construction dates and costs, records of accumulated depreciation applicable to such properties, **and records of Contributions in Aid of Construction**.[2] [Emphasis added.]

Because this payment by the purchasers of lots included the cost of all development infrastructure including the utility systems, it would have been recorded as a contribution in aid of construction ("CIAOC") if the developer were a utility. Instead, the developer sold the utility plant to Aqua, and Aqua failed to reduce the developer's costs by these contributions in aid of construction. As a result, Aqua's proposed rates would require Park South Station homeowners to pay for this same utility plant a second time through a $700 tap fee imposed by Aqua. In addition, Park South Station homeowners are also paying for this same utility plant a third time through current monthly rates that are designed to recover total plant costs from all of Aqua's customers. In my opinion, recognition of an acquisition adjustment by Aqua for the residents of Park South Station is the just and reasonable way to determine the Company's true rate base for stand-alone rates for Park South Station in order to set rates.

Q10. HOW SHOULD THIS ACQUISITION ADJUSTMENT BE CALCULATED?

[2] National Association of Regulatory Utility Commissioners (NARUC) 1996 Uniform System of Accounts for Class C Water Utilities.

A10. In this case, the acquisition adjustment should be equal to the entire purchase price paid by Aqua ($1,200 per lot) since the homeowners have already paid for the entire cost of the water and wastewater plant. Therefore, the entire plant cost recorded to date of $1,334,129 should be charged to account 114 – Utility Plant Acquisition Adjustments, and reflected as a deduction to rate base in this rate case. In addition, the connection charges that have already been received of $700 per lot should be treated as a contribution in aid of construction and also deducted from Aqua's rate base. The result is that Aqua's rate base for Park South Station water and sewer system is zero. With a zero rate base, it would be unjust and unreasonable to charge Park South Station customers a base rate designed to provide a return on Aqua's overall capital investment.

Q11. WAS AN ACQUISITION ADJUSTMENT PROPOSED WHEN THE PARK SOUTH STATION WATER AND WASTEWATER SYSTEMS WERE ACQUIRED FROM THE DEVELOPER?

A11. No. This rate case represents the first opportunity that Park South Station homeowners have had to protest how the rates of Aqua are applied to their Subdivision.

Q12. WOULD A SIMILAR ACQUISITION ADJUSTMENT BE APPROPRIATE FOR AQUA'S OTHER SERVICE TERRITORIES BEYOND PARK SOUTH STATION?

A12. It very well could be. The scope of my analyses has been limited to the Company's acquisition of Park South Station, although I noted that Aqua's Application (Aqua's W-1 Data Item 9 (Book 2 of 4, Part 1); Aqua's W-1 Data Item 9 (Book 2 of 4, Part 2)) included similar Developer's Written Certification of Costs forms for other subdivisions as those that were submitted for Park South Station. There may well be other instances where the Company has acquired water and sewer plant from subdivision developers that has already been paid for by the homeowners but did not take this into account in its rate base. In those instances, a negative acquisition adjustment, limiting the Company's rate base investment to the original net cost after the homeowner's lot purchase from the developer, would be in order.

II. PROPOSED RATE DESIGN FOR PARK SOUTH STATION

Q13. ARE THE RATES PROPOSED BY AQUA JUST AND REASONABLE FOR THE RESIDENTS OF PARK SOUTH STATION?

A13. No. Since the rates proposed by Aqua are designed to recover both investment and operating costs, they are not appropriate for residents of Park South Station. Park South Station customers have already fully paid for the investment cost of the water and wastewater system serving them. In addition, the operating costs of serving residents of Park South Station would already be included in the wholesale water and wastewater charges from CMU.

Q14. WHAT IS THE APPROPRIATE RATE DESIGN FOR THE RESIDENTS OF PARK SOUTH STATION?

A14. I have included Aqua's current charges to Park South Station on Exhibit WHN-2 along with a comparison of CMU's current rates. To begin with, I would propose that the Commission terminate the $700 connection charge to new customers of Park South Station. I would also urge the Commission to refund any prior connection charges back to the homeowners. Since these customers have already paid for the water and wastewater plant that serves them through their lot purchases from the developer, there is no reason for charging them for this same plant a second time through a connection charge.

Next I would point out that utility service to Park South Station most closely resembles the sale for resale services that the Commission is already familiar with since Aqua has no significant plant investment of its own to provide service to Park South Station. Also, since Park South Station actually receives its water and wastewater service from CMU, Aqua has no significant operating costs in serving Park South Station. I would therefore propose that Aqua's rate structure to Park South Station include only the volumetric pass-through operating costs that Aqua pays to CMU along with a nominal charge of $3.75 per month for administrative costs as contained in Chapter 18 of the Commission's "Provision of Water and Sewer Service for Landlords" which reads as follows concerning rates:

Rule R18-6. Rates.
(a) The rates shall equal the cost of purchased water or sewer service (The usage rate charged by the provider shall equal the usage rate charged by the supplier.). **A Commission-approved administrative fee not to exceed $3.75 may be added to the cost of purchased water and sewer service to compensate the provider for meter reading, billing, and collection.** A provider whose schedule of rates and fees does not include a separate base charge to the tenant may request approval of an administrative fee greater than $3.75 to recover the base charge from its supplier. With the exception of base charges approved before August 1, 2004, all charges other than the administrative fee shall be based on tenants' metered consumption of water. All sewer service shall be measured based on the amount of water metered. Metered consumption of water shall be determined by metered measurement of all water consumed by the tenant, and not by any partial measurement of water consumption (i.e., ratio utility billing system (RUBS) and hot water capture, cold water allocation (HWCCWA) are not allowed), unless specifically authorized by the Commission. [Emphasis added.]

Q15. WHAT ARE THE CMU RATES THAT SHOULD BE "PASSED THROUGH" TO RESIDENTS OF PARK SOUTH STATION THROUGH AQUA'S VOLUMETRIC CHARGES?

A15. According to Exhibit O, Pages 1 and 6 of the Company's filing, these pass through rates are $2.73 per 1,000 gallons for water service and $5.747 per 1,000 gallons for wastewater service. However, as shown in Exhibit WHN-3, these rates may be incorrect. The Commission Staff has recalculated CMU's rates to be $2.02 per 1,000 gallons for water service. Whichever rates are correct, I would urge the Commission to adopt the concept of passing through the actual CMU volumetric rates to residents of Park South Station.

Q16. DOES THIS COMPLETE YOUR TESTIMONY?

A16. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available.

CERTIFICATE OF SERVICE

I hereby certify that a copy of *Direct Testimony of William H. Novak on Behalf of PSS Legal Fund* was provided to the persons listed below via email and first class U.S. Mail, postage prepaid.

This the 25th day of May, 2011.

James S. Whitlock

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EXHIBIT WHN-1

William H. Novak Vitae

William H. Novak
19 Morning Arbor Place
The Woodlands, TX 77381

Phone: 713-298-1760
Email: halnovak@whnconsulting.com

Areas of Specialization

Over twenty-five years of experience in regulatory affairs and forecasting of financial information in the rate setting process for electric, gas, water and wastewater utilities. Presented testimony and analysis for state commissions on regulatory issues in four states and has presented testimony before the FERC on electric issues.

Relevant Experience

WHN Consulting – September 2004 to Present
In 2004, established WHN Consulting to provide utility consulting and expert testimony for energy and water utilities. Complete needs consultant to provide the regulatory and financial expertise that enabled a number of small gas and water utilities to obtain their Certificate of Public Convenience and Necessity (CCN) that included forecasting the utility investment and income. Also provided the complete analysis and testimony for utility rate cases including revenues, operating expenses, taxes, rate base, rate of return and rate design for utilities in Tennessee. Assisted American Water Works Company in preparing rate cases in Ohio and Iowa. Provided commercial and industrial tariff analysis and testimony for an industrial intervenor group in a large gas utility rate case. Industry spokesman for water utilities dealing with utility commission rulemaking. Consultant for the North Carolina and Illinois Public Utility Commissions in carrying out their oversight functions of Duke Energy and Peoples Gas Light and Coke Company through focused management audits. Also provide continual utility accounting services and preparation of utility commission annual reports for water and gas utilities.

Sequent Energy Management – February 2001 to July 2003
Vice-President of Regulatory Compliance for approximately two years with Sequent Energy Management, a gas trading and optimization affiliate of AGL Resources. In that capacity, directed the duties of the regulatory compliance department, and reviewed and analyzed all regulatory filings and controls to ensure compliance with federal and state regulatory guidelines. Engaged and oversaw the work of a number of regulatory consultants and attorneys in various states where Sequent has operations. Identified asset management opportunities and regulatory issues for Sequent in various states. Presented regulatory proposals and testimony to eliminate wholesale gas rate fluctuations through hedging of all wholesale gas purchases for utilities. Also prepared testimony to allow gas marketers to compete with utilities for the transportation of wholesale gas to industrial users.

Atlanta Gas Light Company – April 1999 to February 2001

Director of Rates and Regulatory Analysis for approximately two years with AGL Resources, a public utility holding company serving approximately 1.9 million customers in Georgia, Tennessee, and Virginia. In that capacity, was instrumental in leading Atlanta Gas Light Company through the most complete and comprehensive gas deregulation process in the country that involved terminating the utility's traditional gas recovery mechanism and instead allowing all 1.5 million AGL Resources customers in Georgia to choose their own gas marketer. Also responsible for all gas deregulation filings, as well as preparing and defending gas cost recovery and rate filings. Initiated a weather normalization adjustment in Virginia to track adjustments to company's revenues based on departures from normal weather. Analyzed the regulatory impacts of potential acquisition targets.

Tennessee Regulatory Authority – Aug. 1982 to Apr 1999; Jul 2003 to Sep 2004

Employed by the Tennessee Regulatory Authority (formerly the Tennessee Public Service Commission) for approximately 19 years, culminating as Chief of the Energy and Water Division. Responsible for directing the division's compliance and rate setting process for all gas, electric, and water utilities. Either presented analysis and testimony or advised the Commissioners/Directors on policy setting issues, including utility rate cases, electric and gas deregulation, gas cost recovery, weather normalization recovery, and various accounting related issues. Responsible for leading and supervising the purchased gas adjustment (PGA) and gas cost recovery calculation for all gas utilities. Responsible for overseeing the work of all energy and water consultants hired by the TRA for management audits of gas, electric and water utilities. Implemented a weather normalization process for water utilities that was adopted by the Commission and adopted by American Water Works Company in regulatory proceedings outside of Tennessee.

Education

B.A, Accounting, Middle Tennessee State University, 1981
MBA, Middle Tennessee State University, 1997

Professional

Certified Public Accountant (CPA), Tennessee Certificate # 7388
Certified Management Accountant (CMA), Certificate # 7880
Former Vice-Chairman of National Association of Regulatory Utility Commission's Subcommittee on Natural Gas

EXHIBIT WHN-2

Rate Comparison

Exhibit WHN-2
Schedule 1

PSS Legal Fund
Analysis of Bill Calculations for Park South Service Territiory of Aqua Utilities
Charlotte-Mecklenburg Current Rates vs. Proposed Rates for Park South Station

	Charlotte-Mecklenburg Current Rates			Aqua Proposed Rates			Rate Change	
	Usage	**Rate**	**Amount**	**Usage**	**Rate**	**Amount**	**Amount**	**Percent**
Water Charges:								
Customer Charge			$2.40			$18.50	$16.10	670.83%
Usage Charge	1,400	$0.00194	2.71	1,400	$0.00273	3.82	1.11	40.96%
Total Water Charges			**$5.11**			**$22.32**	**$17.21**	**336.79%**
Wastewater Charges:								
Customer Charge			$2.40			$26.34	$23.94	997.50%
Usage Charge	1,400	0.00576	8.07	1,400	0.00575	8.05	-0.02	-0.25%
Total Wastewater Charges			**$10.47**			**$34.39**	**$23.92**	**228.46%**
Total Monthly Bill			**$15.58**			**$56.71**	**$41.13**	**263.99%**

SOURCE FOR CHARLOTTE-MECKLENBURG CURRENT RATES : *November 29, 2010 Guide to Utilities Budget & Water/Sewer Rates.*
SOURCE FOR AQUA PROPOSED RATES: *Company Rate Case Filing, Exhibit O, Schedules 1, 5 and 6.*

Exhibit WHN-2
Schedule 2

PSS Legal Fund
Analysis of Bill Calculations for Park South Service Territiory of Aqua Utilities
Aqua Current Rates vs. Proposed Rates for Park South Station

	Aqua Current Rates			Aqua Proposed Rates			Rate Change	
	Usage	**Rate**	**Amount**	**Usage**	**Rate**	**Amount**	**Amount**	**Percent**
Water Charges:								
Customer Charge			$15.18			$18.50	$3.32	21.87%
Usage Charge	1,400	$0.00476	6.66	1,400	$0.00273	3.82	-2.84	-42.64%
Total Water Charges			**$21.84**			**$22.32**	**$0.48**	**2.20%**
Wastewater Charges:								
Customer Charge			$63.33			$26.34	-$36.99	-58.41%
Usage Charge	1,400	0.00000	0.00	1,400	0.00575	8.05	8.05	100.00%
Total Wastewater Charges			**$63.33**			**$34.39**	**-$28.94**	**-45.70%**
Total Monthly Bill			**$85.17**			**$56.71**	**-$28.46**	**-33.42%**

SOURCE: *Company Rate Case Filing, Exhibit O, Schedules 1, 5 and 6.*

EXHIBIT WHN-3

Proposed Water Rate

From: Tweed, Jerry
Sent: Thursday, May 19, 2011 5:02 PM
To: Grantmyre, William
Subject: RE: Docket W-218, Sub 319 - Data Request

The Company requested a $2.73/1,000 gallon water rate based upon an apparent misreading of Charlotte's tariff. They are actually being charged a water rate of $1.94/1,000 gallons ($1.45/ccf). When grossed up for gross receipts tax and regulatory fee my recommended rate will be $2.02/1,000 gallons.

Jerry H. Tweed

Public Staff - Water & Sewer Division

Tel: (919) 733-0891(919) 733-0891