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BEFORE THE ARIZONA CORPORATION C

COMMISSIONERS
MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY ELECTRIC COOPERATIVE, INC. FOR AN ORDER SETTING JUST AND REASONABLE RATES.	DOCKET NO. E-01749A-07-0236 **NOTICE OF FILING STAFF'S DIRECT TESTIMONY**

Staff hereby provided notice of filing its Direct Testimony on Rate Design and Cost of Service in this Docket. An original and thirteen copies are submitted of the Prefiled Direct Testimony of William H. Musgrove and Prem K. Bahl.

RESPECTFULLY SUBMITTED this 6th day of November, 2007.

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for Kevin O. Torrey
Attorney, Legal Division
Arizona Corporation Commission
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Original and thirteen (13) copies of the foregoing were filed this 6th day of November, 2007 with:

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Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

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Copy of the foregoing mailed this 6th day of November, 2007 to:

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Phoenix, Arizona 85034

Sharyn Bal

DIRECT

TESTIMONY

OF

WILLIAM H. MUSGROVE

PREM K. BAHL

DOCKET NO. E-01749A-07-0236

IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY ELECTRIC COOPERATIVE INC. FOR A DETERMINATION OF THE FAIR VALUE OF ITS PROPERTY AND FOR AN ORDER SETTING JUST AND REASONABLE RATES

NOVEMBER 06, 2007

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY ELECTRIC COOPERATIVE INC. FOR A DETERMINATION OF THE FAIR VALUE OF ITS PROPERTY AND FOR AN ORDER SETTING JUST AND REASONABLE RATES	DOCKET NO. E-01749A-07-0236

DIRECT

TESTIMONY

OF

WILLIAM H. MUSGROVE

ON BEHALF OF STAFF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 6, 2007

TABLE OF CONTENTS

Page

INTRODUCTION 1

REVENUE ALLOCATION AND RATE DESIGN 2

TARIFF CHANGES 8

SERVICE-RELATED CHARGES 9

UNBUNDLED TARIFFS 10

MISCELLANEOUS TARIFF MATTER 11

SUMMARY OF STAFF'S RECOMMENDATIONS 13

SCHEDULES

Rate Design WHM-1

Typical Bill Analysis WHM-2

Unbundled Rate Design WHM-3

EXECUTIVE SUMMARY
GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01749A-07-0236

Staff's testimony addresses Revenue Allocation and Rate Design, Tariff Changes, Service-Related Charges, Unbundled Tariffs and the need for a bill estimation tariff for Graham County Electric Cooperative, Inc. ("Graham"). Staff's recommendations are summarized below:

1. Revenue Allocation and Rate Design
   Staff concludes and recommends that Graham should be granted a revenue increase in the amount of $2,106,584 or 15.19 percent compared to Staff's adjusted present revenues in the amount of $13,870,731. Staff's recommended energy rates are designed to collect $14,452,998 ($2,106,584 + $12,346,414) in revenue or an increase of 17.06 percent compared to Graham's existing unadjusted present revenues in the amount of $12,346,414. A rate class summary of these data is depicted on page 3 of Staff's testimony. Revenue allocation was limited to energy/commodity rates because Graham did not request any increases to the existing monthly minimum charge rates.

2. Tariff Changes
   Staff recommends that the proposed housekeeping and power requirement changes to the rate schedules be approved. The recommended changes harm no existing customer classes and benefit the Residential class by lowering the cost to operate well pumps when used for residential purposes.

3. Service-Related Charges
   Staff supports the removal of field collection of delinquent accounts service because the service exposes Graham's employees to the risk of incurring personal injuries.

4. Unbundled Tariffs
   Staff recommends that the proposed unbundled rates that are summarized in Exhibit WHM-3 be approved.

5. Bill Estimation Tariff
   Within thirty days of a decision in this matter, Staff recommends that Graham be required to submit, through Docket Control for Commission approval, a separate tariff describing its bill estimation methodologies.

INTRODUCTION

Q. Please state your name and business address.

A. My name is William H. Musgrove. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. What is the nature of your work relationship with the Arizona Corporation Commission?

A. I am an Independent Contractor providing utilities consulting services to the Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff").

Q. Please state your educational background and business experience.

A. I received a Master of Business Administration Degree with a tested concentration in Finance and an elected concentration in Economics from Loyola College located in Baltimore, Maryland. I also received a Bachelor of Science Degree with a concentration in Business Administration from Johns Hopkins University located in Baltimore, Maryland, and later augmented the Undergraduate Degree with college-level mathematics credits that were also received from Johns Hopkins University. I am a tested Certified Energy Manager as certified by the Association of Energy Engineers. My business experiences entail 40-plus years in various positions with the Baltimore Gas and Electric Company ("BGE"). The positions relevant to the testimony I am sponsoring in this Proceeding involve more than 10 years experience in the Economic Research Department at BGE. During that period, I became fully proficient in understanding gas and electric utility financial records and the rate making process. I am thoroughly familiar with all phases and components of a gas or electric rate cases, including rate design and Cost of Service protocols.

Q. Have you previously testified before any regulatory commission?

A. Yes. I appeared before the Arizona Corporation Commission in 2005 during a Southwest Gas Corporation proceeding (Docket No. G-01551A-04-0876). I have also testified before the Public Service Commission of Maryland regarding rate design and new service application matters.

Q. What is the scope of your testimony in this case?

A. My testimony will present the Staff's position and recommendations regarding Graham County Electric Cooperative's ("Graham" or "Cooperative") application for a general rate increase. Staff's testimony specifically addresses the topics of revenue allocation and rate design, proposed tariff changes, service-related charges, unbundled tariffs and a miscellaneous tariff matter. Staff witnesses Jerry Anderson, Gerald Becker and Prem Bahl will provide testimonies regarding other aspects of Graham's rate application.

REVENUE ALLOCATION AND RATE DESIGN

Q. Please describe Staff's revenue allocations.

A. Graham's revised cost of service study illustrates that to varying degrees, the Residential, Irrigation, Small Commercial and Large Commercial rate classes are currently paying less than their cost of service. After incorporating Staff's adjustments, the overall system rate of return remains negative at a minus 0.66 percent, led by the Irrigation class at a minus 8.31 percent rate of return. Staff is recommending increasing the Residential class' energy rates by 19.2 percent, Irrigation class' energy rates by 20.7 percent and Small and Large Commercial classes' energy rates by 18.6 percent and 16.5 percent, respectively. Graham's revised cost of service study also illustrates that the Security and Street Lighting classes are currently providing relatively modest rates of return at 0.76 percent and 5.05 percent, respectively. Although incorporating Staff's adjustments changed Security and

Street Lighting rates of return to 0.12 and 17.89 percent, respectively, Staff recommends increasing their energy rates 28.1 and 19.1 percent, respectively. Staff will discuss the proposed changes later in its testimony.

Q. Has Staff developed a table that summarizes the revenue impact of its recommended rates upon each rate class?

A. The following table summarizes revenue increases as recommended by Staff for all rate classes:

Summary of Revenues from Customer Charges and Sales

Rate Class	Present $	Proposed $	$ Increase	% Increase
Residential	$6,052,122	$7,073,820	$1,021,698	16.88%
Irrigation	$1,521,557	$1,798,424	$276,867	18.20%
Commercial-Sm.	$2,448,009	$2,879,581	$431,572	17.63%
Commercial-Lg.	$2,205,207	$2,566,745	$361,538	16.39%
Security Lgts.	$108,800	$121,659	$12,859	11.82%
Street Lgts.	$10,719	$12,769	$2,050	19.13%
Totals	$12,346,414	$14,452,998	$2,106,584	17.06%

Q. Please describe Staff's rate design.

A. A summary of Staff's proposed rate design is provided on Schedule WHM-1. Graham's present rate design is based on a monthly customer charge known as Service Availability Charges ("SAC"), and flat kWh energy or commodity rates. Graham's rates do not include time-of-use rates. Graham has filed monthly service charges that are identical to existing SAC and is proposing no increase to the current monthly minimum SAC rates. Staff accepts the Cooperative's existing monthly minimum Service Availability Charges as being reasonable for future billings. Regarding commodity rates, Staff has

recommended commodity rates below what the Cooperative proposed for all rate classes except the Security and Street Lighting classes.

Q. Even though Graham did not propose time-of-use rates, why did Staff not propose any such rates?

A. Staff is conducting research on time-of-use rates in Docket No. E-01345A-07-0448. That docket will gather information on time-of-use rates for Arizona Public Service Company and also on a generic basis for other utilities. Staff prefers to complete that inquiry before recommending time-of-use rates for Graham.

Q. Did Staff base its revenue allocations and rate design solely on Staff's cost of service study?

A. No. Staff's recommended rates reflect the combined consideration of setting rates that more accurately reflect classes cost of service, gradualism in change and Staff's recommended revenue requirement for Graham.

Q. Will Staff be addressing the matters of cost of service and revenue requirement?

A. Yes. Staff witnesses Prem Bahl and Gerald Becker will be addressing cost of service and revenue requirement matters, respectively.

Q. Please further describe Staff's recommended rate design and its effect on Graham's various customer classes.

A. A typical bill analysis reflecting the effect of Staff's recommended rate changes on customers with various kWh usage levels is provided on schedule WHM-2. For the Residential rate class, Staff believes that Graham's decision to retain the existing $9.00 per month Service Availability Charge is reasonable. Staff is recommending that the

proposed commodity rate be set at $0.10144 per kWh versus the Cooperative's proposed rate of $0.10695 per kWh. Based on an average residential customer's usage of 775 kWh per month, Staff's recommended rates will raise an average residential customer's bill by $12.66 or 16.88 percent.

For the Irrigation rate class, Staff believes that Graham's decision to retain the existing $23.00 per month Service Availability Charge is reasonable. Staff is recommending that the proposed commodity rate be set at $0.10563 per kWh versus the Cooperative's proposed rate of $0.10998 per kWh. Based on an average irrigation customer's usage of 1,916 kWh per month, Staff's recommended rates will raise an average irrigation customer's bill by $34.70 or 18.20 percent. Regarding the Irrigation class, it should be noted that its rate of return is the lowest of all rate classes under both Graham's revised and Staff's adjusted cost of service studies.

For the Small Commercial rate class (non-residential customers requiring less than 350 KVA of transformer capacity), Staff believes that Graham's decision to retain the existing $15.00 per month Service Availability Charge is reasonable. Staff is recommending that the proposed commodity rate be set at $0.10101 per kWh versus the Cooperative's proposed rate of $0.10702 per kWh. Based on an average small commercial customer's usage of 3,161 kWh per month, Staff's recommended rates will raise an average small commercial customer's bill by $50.10 or 17.63 percent.

For the Large Commercial rate class (customers between and including 350 KVA and a proposed upper limit of 2,500 KVA), Staff believes that Graham's decision to retain the existing $50.00 per month Service Availability Charge is reasonable. Staff is recommending that the proposed commodity rate be set at $0.09167 per kWh versus the

Cooperative's proposed rate of $0.09892 per kWh. Based on an average large commercial customer's usage of 186,120 kWh per month, Staff's recommended rates will raise an average large commercial customer's bill by $2,410.25 or 16.39 percent.

The Security Lighting tariff identifies electric service at 70 kWh per month (small) or 175 kWh (large) per month. Staff believes that the Cooperative's decision to retain the existing monthly customer service charges in the amounts of $5.77 and $7.06 for small and large customers, respectively, is reasonable. The commodity rate for small and large security light customers is equal. Staff believes that the Cooperative's revised proposed commodity rate of $0.07472 per kWh should be increased to $0.07651 per kWh. The commodity rate incremental increase in the amount of approximately 18 mills is driven by Staff's recommendation that the base cost of purchased power should equal $0.076509 per kWh compared to the existing base cost of purchased power in the amount of $0.060034 per kWh. Staff's proposed commodity rate will help the Cooperative in recovering increased purchased power costs and is therefore recommending that the commodity be at least equal to the recommended base cost of purchased power. Mr. Jerry Anderson will address the base cost of purchased power in his testimony. Staff's proposed rates will raise a small security light customer's monthly bill, per light, by $1.18 or 11.82 percent and a large security light customer's bill by $2.94 or 16.79 percent.

The Street Lighting tariff identifies electric service at 70 kWh (small) or 175 kWh (large) per month. There is no monthly customer charge for street lighting customers. Staff believes that the Cooperative's proposed commodity rate of $0.09829 per kWh should be increased to $0.09922 per kWh. The commodity rate incremental increase in the amount of approximately 1 mill is driven by Staff's recommendation that the base cost of purchased power should equal $0.076509 per kWh compared to the existing base cost of

purchased power in the amount of $0.060034 per kWh. Staff's proposed commodity rate will help the Cooperative in recovering increased purchased power costs. Staff's proposed rate will raise a small street lighting customer's monthly bill by $1.11 or 19.12 percent and a large street lighting customer's bill by $2.79 or 19.12 percent.

Q. Why do the percent increases on Exhibits WHM-1 and WHM-2 reflect higher percent increases compared to the increases discussed in Mr. Wallace's testimony?

A. The increases in rates proposed by Graham are derived by including a purchased power adjustor ("PPA") in present rates. Staff's present rates shown in Exhibits WHM-1 and WHM-2 exclude a purchased power adjustor to reflect actual base rates contained in Graham's tariffs. Using the residential class as an example, the following table illustrates how these different methodologies produce significantly different results:

	Graham			Staff		
	Present Rates	Proposed Rates	% Change	Present Rates	Proposed Rates	% Change
Base kWh Rate	$.08511	$.10695	25.66	$.08511	$.10144	19.19
PPA	$.01500	$0	-	$0	$0	-
Total Rate	$.10011	$.10695	6.83	$.08511	$.10144	19.19
Average kWh	775	775	-	775	775	-
Total Bill w/$9 Customer Charge	$86.59	$91.89	6.12	$74.96	$87.62	16.88

Q. Why does Staff prefer using a comparative approach that demonstrates rate increases approximately in the 17-19 percent range rather than the approximate 6-7 percent range presented by Graham?

A. Both approaches are valid and demonstrate different points of view. Staff prefers its approach for the following reasons: 1) both Staff's and Graham's present base commodity

tariff rates exclude a purchased power adjustor; 2) Staff's approach compares present and proposed base commodity rates that only include the base cost of power plus O&M-related costs that make up the total base commodity tariff rate; 3) although the existing PPA may be set to zero in this rate case, nothing prevents Graham from increasing the PPA, without Commission approval, if the purchased power "bank" balance indicates an under collection; and, 4) Staff's exhibits WHM-1 and WHM-2 have been prepared in the same format as the exhibits submitted by Staff and accepted by the Commission in Graham's previous rate case filed September 13, 2002.

Q. Will Staff's rate design testimony include further discussions about the cost of purchased power and the recovery of those costs?

A. Purchased power costs and their recovery will be discussed in direct testimony prepared by Mr. Jerry D. Anderson.

Q. What does Staff recommend regarding its proposed rates?

A. Staff recommends that the rates proposed by Staff and summarized on Exhibit WHM-1 be approved.

TARIFF CHANGES

Q. Were there other rate design-related changes filed by Graham that impact rate schedules contained in the Cooperative's existing tariff?

A. Yes. On July 24, 2007, Staff requested responses to data requests issued for the purpose of clarifying what if any impact proposed tariff changes would have on customers served under their respective rate schedules. Based on Graham's responses, Staff recommends that the proposed changes be approved. The changes are mostly housekeeping in nature. For example, minimum power factor was increased from 90 percent to 95 percent for all

applicable rate schedules to align Graham's tariffs with its supplier's (Arizona Electric Power Cooperative) tariff to avoid incurring operation penalties from its supplier. To date, Graham or its customers have not been penalized for not maintaining a 95 percent power factor. Other changes fell into the category of increasing or decreasing equipment size and power requirement hurdles to be eligible for certain rate schedules. According to Graham's responses, no existing customers will be adversely impacted by these changes. For example, residential customers are expected to save approximately $75 per year by being entitled to meter domestic water pumps under the residential rate schedule.

SERVICE-RELATED CHARGES

Q. Were there any service-related charge changes proposed by Graham?

A. Yes.

Q. What does Staff recommend regarding Graham's proposed changes to its service-related charges?

A. Staff recommends that changes to Graham's service-related charges be approved. Graham did not increase any of its existing service-related charges as can be seen on Exhibit WHM-1. Graham did, however, eliminate a $10 service charge associated with the field collection of delinquent accounts. Based on information provided by the Cooperative, the field collection delinquent account service was removed because of concern for employee safety. Employees could be in the field carrying cash in the amount of the delinquent bill plus the $10 service charge. Staff's review of Section R14-2-211 of the Arizona Administrative Code entitled Termination of Service did not uncover any language that prohibits Graham from eliminating this service. On the contrary, the Code permits the disconnection of service without advance written notice in cases where there is the existence of an obvious hazard to the safety or health of the utility's personnel. Staff's

position is based on the assumption that Graham will remain in compliance with all of the procedural requirements and guidelines contained in the Code.

UNBUNDLED TARIFFS

Q. Please provide a background on Graham's unbundled tariffs.

A. Graham's unbundled tariffs break down the monthly customer charges and commodity rates into individual components of service. The monthly customer charge is further broken down into the following charges: a service availability charge, a metering charge, a meter reading charge, a billing charge and an information and service charge. The commodity rate is further broken down into the following components: a distribution delivery charge (formerly known as the kWh Delivery Charge Energy), a transmission delivery charge, an energy charge, a demand charge and a transmission charge. The energy charge, demand charge and transmission charge components of the commodity rate reflect Graham's cost to provide energy received from the Arizona Electric Power Cooperative ("AEPCO") and its affiliated entities. Consequently, if Graham's territory is open to competition, a customer opting to take service from a competitive generation provider would not pay the energy charge, demand charge and transmission charge components of the commodity rate to Graham.

Staff reviewed Graham's bundled Cost of Service study and agreed that it had been prepared accurately and in conformance with previous Commission orders. The testimony of Mr. Prem Bahl addresses the bundled Cost of Service study filed by Graham. The unbundled Cost of Service ("COS") study is in compliance with Decision No. 66382 in that it includes the Street Light class. In his Direct Testimony, Mr. Wallace indicates that it would be too expensive to develop a fully viable unbundled COS study, and he provides several reasons why the Commission should accept the unbundled COS study provided to

the Commission. Staff believes that it is necessary to have an unbundled COS study to accommodate possible competition, and in light of the fact that the data contained in the unbundled study filed by Graham may help prospective customers better understand the pricing of electricity in a competitive environment, Staff recommends that the Commission accept the unbundled COS study filed by Graham in this rate case. It should be noted that Mr. Wallace recognizes Graham's responsibility to provide a complete, accurate and timely unbundled COS study if Graham's territory is opened to competition.

Q. Graham's proposed unbundled rates do not reflect Staff's adjustments to the Test Year and rate recommendations. Has Staff completed an unbundled cost of service study?

A. Yes. The adjustments and revenue recommendations developed by Staff have been incorporated into the COS study as unbundled by Graham. Exhibit WHM-3 provides a summary of Staff's proposed unbundled rate design.

Q. What does Staff recommend regarding the proposed unbundled rates for Graham?

A. Staff recommends that the proposed unbundled rates summarized in Exhibit WHM-3 be approved. The proposed unbundled rates do not result in any incentive or disincentive for customers who want to choose competitive generation suppliers, because the unbundled rates conform to the standard offer rates.

MISCELLANEOUS TARIFF MATTER

Q. Does Staff wish to address any additional issues related to the rate case proceeding?

A. Yes. The provisions in Graham's Rules and Regulations do not contain detailed and specific bill estimation procedures that would be implemented in cases where Graham is unable to obtain actual meter reads. In recent decisions regarding Arizona Public Service

Company (Decision No. 69569) and Trico Electric Cooperative (Decision No. 68073), the Commission ordered Arizona Public Service Company and Trico Electric Cooperative to file separate tariffs describing its bill estimation methodologies.

Q. What does staff recommend regarding Graham's bill estimation procedures?

A. Staff recommends that Graham submit through Docket Control a separate tariff describing its bill estimation methodologies for Commission approval within thirty days of a decision in this matter. The tariff should address, but not be limited to, the following terms and conditions:

a. Conditions under which estimated bills will be billed to customers.

b. Notice of estimation clearly noted on estimated bills that are rendered to customers.

c. Estimation procedures that explicitly address the conditions and procedures for estimated bills such as kWh estimates where: i) at least one year of premise history exists for the same customer at the same premise or a new customer with at least one year of premise history; ii) less than one year of premise history for the same customer at the same premise exists; iii) less than one year of premise history exists for a new customer but some premise history exists for the new customer; and, iv) no prior consumption history exists.

d. Variations in estimation methods for differing conditions such as cases involving meter tampering or damaged meters.

e. Conditions where bill estimations will be developed automatically or manually.

f. Conditions where special procedures may be required such as the installation of meters with automatic reading capabilities, the need to

estimate first and final bills, and the requirement to use customer specific data to complete an estimate.

g. Where applicable, clearly indicate that estimation procedures will be in compliance with the appropriate section of the Arizona Administrative Code [e.g. Section R14-2-210(A)].

SUMMARY OF STAFF'S RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. Staff recommends increasing the Residential class' energy rate by 19.2 percent, Irrigation class' energy rate by 20.7 percent, Small and Large Commercial classes' energy rates by 18.6 percent and 16.5 percent, respectively (see WHM-1).
2. Staff recommends increasing the Security and Street Lighting classes' energy rates by 28.1 percent and 19.1 percent, respectively (see WHM-1).
3. All existing monthly Service Availability rates will remain unchanged, and Staff believes that these rates are reasonable.
4. For the Residential rate class, Staff recommends that the commodity rate be set at $0.10144 per kWh compared to the Cooperative's proposed rate of $0.10695 per kWh.
5. For the Irrigation rate class, Staff recommends that the commodity rate be set at $0.10563 per kWh compared to the Cooperative's proposed rate of $0.10998 per kWh.
6. For the Small Commercial rate class, Staff recommends that the commodity rate be set at $0.10101 per kWh compared to the Cooperative's proposed rate of $0.10702 per kWh.
7. For the Large Commercial rate class, Staff recommends that the commodity rate be set at $0.09167 per kWh compared to the Cooperative's proposed rate of $0.09892 per kWh.

8. Staff recommends that the proposed housekeeping and power requirement changes to the rate schedules be approved.
9. Staff recommends that the proposed change to Graham's service-related charges be approved.
10. Staff recommends that the proposed unbundled rates summarized in Exhibit WHM-3 be approved.
11. Within thirty days of a decision in this matter, Staff recommends that Graham be required to submit, through Docket Control for Commission approval, a separate tariff describing its bill estimation methodologies.

Q. Does this conclude your testimony?

A. Yes.

Rate Design
Graham County Electric Cooperative, Inc.
Docket No. E-1749A-07-0236
Test Year Ended September 30, 2006

RATE DESIGN

	Present Rates	Proposed Rates			
		Company	% Change	Staff	% Change
MONTHLY MINIMUM CHARGE					
Residential	$9.00	$9.00	0.0%	$9.00	0.0%
Small Commercial	$15.00	$15.00	0.0%	$15.00	0.0%
Large Commercial	$50.00	$50.00	0.0%	$50.00	0.0%
Irrigation	$23.00	$23.00	0.0%	$23.00	0.0%
Security Lighting					
Small Security Light	$5.77	$5.77	0.0%	$5.77	0.0%
Large Security Light	$7.06	$7.06	0.0%	$7.06	0.0%
Street Lighting	$0.00	$0.00	0.0%	$0.00	0.0%
ENERGY (COMMODITY) RATE - PER KWH					
Residential	$0.08511	$0.10695	25.7%	$0.10144	19.2%
Small Commercial	$0.08516	$0.10702	25.7%	$0.10101	18.6%
Large Commercial	$0.07872	$0.09892	25.7%	$0.09167	16.5%
Irrigation	$0.08752	$0.10998	25.7%	$0.10563	20.7%
Security Lighting	$0.05971	$0.07472	25.1%	$0.07651	28.1%
Street Lighting	$0.08329	$0.09829	18.0%	$0.09922	19.1%
PURCHASED POWER FUEL ADJUSTOR - PER KWH					
All Customer Classes (present rate per GCEC)	$0.01500	$0.00000	-100.0%	$0.00000	-100.0%
SERVICE RELATED CHARGES					
New or Additional Service Connection	$10.00	$10.00	0%	$10.00	0%
Service Connection Callbacks	$10.00	$10.00	0%	$10.00	0%
Service Calls after Regular Business Hours	$50.00	$50.00	0%	$50.00	0%
Disconnects	$10.00	$10.00	0%	$10.00	0%
Reconnects During Regular Business Hours	$10.00	$10.00	0%	$10.00	0%
Reconnects After Normal Working Hours	$30.00	$30.00	0%	$30.00	0%
Field Collection Delinquent Accounts	$10.00	Service eliminated by GCEC			
Returned Check Fee	$25.00	$25.00	0%	$25.00	0%
Late Payment Charge	1.5%	1.5%	0%	1.5%	0%
Meter Test	$10.00	$10.00	0%	$10.00	0%
Meter Rereads (if original read was not in error)	$10.00	$10.00	0%	$10.00	0%

TYPICAL BILL ANALYSIS

Notes: 1) Present Rates exclude a GCEC reported fuel adjustor charge of $0.015 per kWh.
2) Staff proposed lighting schedules rates include a $.076509 base cost of purchased power.

COMPANY PROPOSED

Customer Class	Average kWh Per Month	Present Rates	Company Proposed Rates	Dollar Increase	Percent Increase
Residential	775	$74.96	$91.89	$16.93	22.58%
Small Commercial	3,161	$284.19	$353.29	$69.10	24.31%
Large Commercial	186,120	$14,701.37	$18,460.99	$3,759.62	25.57%
Irrigation	1,916	$190.69	$233.72	$43.03	22.57%
Security Lgt-Sm. (per lgt.)	70	$9.95	$11.00	$1.05	10.56%
Security Lgt-Lg. (per lgt.)	175	$17.51	$20.14	$2.63	15.00%
Street Lgt-Sm. (per lgt.)	70	$5.83	$6.88	$1.05	18.01%
Street Lgt-Lg. (per lgt.)	175	$14.58	$17.20	$2.63	18.01%

STAFF PROPOSED

Customer Class	Average kWh Per Month	Present Rates	Staff Proposed Rates	Dollar Increase	Percent Increase
Residential	775	$74.96	$87.62	$12.66	16.88%
Small Commercial	3,161	$284.19	$334.29	$50.10	17.63%
Large Commercial	186,120	$14,701.37	$17,111.62	$2,410.25	16.39%
Irrigation	1,916	$190.69	$225.39	$34.70	18.20%
Security Lgt-Sm. (per lgt.)	70	$9.95	$11.13	$1.18	11.82%
Security Lgt-Lg. (per lgt.)	175	$17.51	$20.45	$2.94	16.79%
Street Lgt-Sm. (per lgt.)	70	$5.83	$6.95	$1.11	19.12%
Street Lgt-Lg. (per lgt.)	175	$14.58	$17.36	$2.79	19.12%

RESIDENTIAL

Monthly kWh Consumption	Present Rates	Company Proposed Rates	Company Percent Increase	Staff Proposed Rates	Staff Percent Increase
60	$14.11	$15.42	9.29%	15.09	6.95%
100	$17.51	$19.70	12.47%	19.14	9.33%
200	$26.02	$30.39	16.79%	29.29	12.55%
500	$51.56	$62.48	21.18%	59.72	15.84%
1000	$94.11	$115.95	23.21%	110.44	17.35%
1500	$136.67	$169.43	23.97%	161.16	17.92%
2000	$179.22	$222.90	24.37%	211.88	18.22%
2500	$221.78	$276.38	24.62%	262.60	18.41%
3000	$264.33	$329.85	24.79%	313.32	18.53%
4000	$349.44	$436.80	25.00%	414.76	18.69%
5000	$434.55	$543.75	25.13%	516.20	18.79%

TYPICAL BILL ANALYSIS - Continued

COMMERCIAL SMALL

Monthly kWh Consumption	Present Rates	Company Proposed Rates	Company Percent Increase	Staff Proposed Rates	Staff Percent Increase
60	20.11	21.42	6.52%	21.06	4.73%
120	25.22	27.84	10.40%	27.12	7.54%
2,000	185.32	229.04	23.59%	217.02	17.11%
4,000	355.64	443.08	24.59%	419.04	17.83%
5,000	440.80	550.10	24.80%	520.05	17.98%
10,000	866.60	1,085.20	25.23%	1,025.10	18.29%
15,000	1,292.40	1,620.30	25.37%	1,530.15	18.40%
20,000	1,718.20	2,155.40	25.45%	2,035.20	18.45%
25,000	2,144.00	2,690.50	25.49%	2,540.25	18.48%
30,000	2,569.80	3,225.60	25.52%	3,045.30	18.50%
35,000	2,995.60	3,760.70	25.54%	3,550.35	18.52%
40,000	3,421.40	4,295.80	25.56%	4,055.40	18.53%
45,000	3,847.20	4,830.90	25.57%	4,560.45	18.54%
50,000	4,273.00	5,366.00	25.58%	5,065.50	18.55%
100,000	8,531.00	10,717.00	25.62%	10,116.00	18.58%
150,000	12,789.00	16,068.00	25.64%	15,166.50	18.59%
200,000	17,047.00	21,419.00	25.65%	20,217.00	18.60%
250,000	21,305.00	26,770.00	25.65%	25,267.50	18.60%
300,000	25,563.00	32,121.00	25.65%	30,318.00	18.60%

COMMERCIAL LARGE

Monthly kWh Consumption	Present Rates	Company Proposed Rates	Company Percent Increase	Staff Proposed Rates	Staff Percent Increase
1,000	128.72	148.92	15.69%	141.67	10.06%
2,000	207.44	247.84	16.30%	233.34	12.49%
4,000	364.88	445.68	18.13%	416.68	14.20%
5,000	443.60	544.60	18.55%	508.35	14.60%
10,000	837.20	1,039.20	19.44%	966.70	15.47%
15,000	1,230.80	1,533.80	19.75%	1,425.05	15.78%
20,000	1,624.40	2,028.40	19.92%	1,883.40	15.94%
25,000	2,018.00	2,523.00	20.02%	2,341.75	16.04%
30,000	2,411.60	3,017.60	20.08%	2,800.10	16.11%
35,000	2,805.20	3,512.20	20.13%	3,258.45	16.16%
40,000	3,198.80	4,006.80	20.17%	3,716.80	16.19%
45,000	3,592.40	4,501.40	20.19%	4,175.15	16.22%
50,000	3,986.00	4,996.00	20.22%	4,633.50	16.24%
100,000	7,922.00	9,942.00	20.32%	9,217.00	16.35%
150,000	11,858.00	14,888.00	20.35%	13,800.50	16.38%
500,000	39,410.00	49,510.00	20.40%	45,885.00	16.43%
1,000,000	78,770.00	98,970.00	20.41%	91,720.00	16.44%
1,500,000	118,130.00	148,430.00	20.41%	137,555.00	16.44%

TYPICAL BILL ANALYSIS - Continued

IRRIGATION		Company		Staff	
Monthly kWh Consumption	Present Rates	Proposed Rates	Percent Increase	Proposed Rates	Percent Increase
500	66.76	77.99	16.82%	75.82	13.56%
750	88.64	105.49	19.00%	102.22	15.32%
1000	110.52	132.98	20.32%	128.63	16.39%
1250	132.40	160.48	21.20%	155.04	17.10%
1500	154.28	187.97	21.84%	181.45	17.61%
1750	176.16	215.47	22.31%	207.85	17.99%
2000	198.04	242.96	22.68%	234.26	18.29%
2250	219.92	270.46	22.98%	260.67	18.53%
2500	241.80	297.95	23.22%	287.08	18.72%
2750	263.68	325.45	23.42%	313.48	18.89%
3000	285.56	352.94	23.60%	339.89	19.03%
3250	307.44	380.44	23.74%	366.30	19.14%
3500	329.32	407.93	23.87%	392.71	19.25%
3750	351.20	435.43	23.98%	419.11	19.34%
4000	373.08	462.92	24.08%	445.52	19.42%
4250	394.96	490.42	24.17%	471.93	19.49%
4500	416.84	517.91	24.25%	498.34	19.55%
4750	438.72	545.41	24.32%	524.74	19.61%
5000	460.60	572.90	24.38%	551.15	19.66%
5250	482.48	600.40	24.44%	577.56	19.71%
5500	504.36	627.89	24.49%	603.97	19.75%
5750	526.24	655.39	24.54%	630.37	19.79%
6000	548.12	682.88	24.59%	656.78	19.82%
6250	570.00	710.38	24.63%	683.19	19.86%
6500	591.88	737.87	24.67%	709.60	19.89%
6750	613.76	765.37	24.70%	736.00	19.92%
7000	635.64	792.86	24.73%	762.41	19.94%
7250	657.52	820.36	24.77%	788.82	19.97%
7500	679.40	847.85	24.79%	815.23	19.99%
7750	701.28	875.35	24.82%	841.63	20.01%
8000	723.16	902.84	24.85%	868.04	20.03%
8250	745.04	930.34	24.87%	894.45	20.05%
8500	766.92	957.83	24.89%	920.86	20.07%
8750	788.80	985.33	24.91%	947.26	20.09%
9000	810.68	1,012.82	24.93%	973.67	20.11%
9250	832.56	1,040.32	24.95%	1,000.08	20.12%
9500	854.44	1,067.81	24.97%	1,026.49	20.14%
9750	876.32	1,095.31	24.99%	1,052.89	20.15%
10000	898.20	1,122.80	25.01%	1,079.30	20.16%
10250	920.08	1,150.30	25.02%	1,105.71	20.18%
10500	941.96	1,177.79	25.04%	1,132.12	20.19%
10750	963.84	1,205.29	25.05%	1,158.52	20.20%
11000	985.72	1,232.78	25.06%	1,184.93	20.21%

Unbundled Rate Design
Graham Coounty Electric Cooperative, Inc.
Docket No. E-1749A-07-0236
Test Year Ended September 30, 2006

UNBUNDLED RATE DESIGN-REVISED (manual input data work paper)

Classification	Type of Charge	Present Rate	Cooperative Proposed Rates	Staff Proposed Rates
Residential	Service Availability Charge	$4.64	$4.60	$4.60
	Metering	1.04	$1.08	$1.08
	Meter Reading	0.68	$0.68	$0.68
	Billing	1.85	$1.85	$1.85
	Info & Service	0.79	$0.79	$0.79
	Bundled Monthly Minimum	**$9.00**	**$9.00**	**$9.00**
	Distribution Delivery Charge	$0.02286	$0.03084	$0.02925
	Transmission Delivery Charge	$0.00034	$0.00031	$0.00029
	Energy Charge	$0.02358	$0.03490	$0.03310
	Demand Charge	$0.02905	$0.03020	$0.02864
	Transmission Charge	$0.00928	$0.01070	$0.01015
	Bundled Commodity Charge per kWh	**$0.08511**	**$0.10695**	**$0.10144**
Small Commercial	Service Availability Charge	$10.50	$10.46	$10.46
	Metering	1.18	1.22	1.22
	Meter Reading	0.68	0.68	0.68
	Billing	1.85	1.85	1.85
	Info & Service	0.79	0.79	0.79
	Bundled Monthly Minimum	**$15.00**	**$15.00**	**$15.00**
	Distribution Delivery Charge	$0.02364	$0.03270	$0.03086
	Transmission Delivery Charge	$0.00040	$0.00030	$0.00028
	Energy Charge	$0.02358	$0.03490	$0.03294
	Demand Charge	$0.02845	$0.02809	$0.02651
	Transmission Charge	$0.00909	$0.01103	$0.01041
	Bundled Commodity Charge per kWh	**$0.08516**	**$0.10702**	**$0.10101**
Large Commercial	Service Availability Charge	$40.12	$39.88	$39.88
	Metering	$5.88	$6.12	$6.12
	Meter Reading	$1.36	$1.36	$1.36
	Billing	$1.85	$1.85	$1.85
	Info & Service	$0.79	$0.79	$0.79
	Bundled Monthly Minimum	**$50.00**	**$50.00**	**$50.00**
	Distribution Delivery Charge	$0.02748	$0.03282	$0.03041
	Transmission Delivery Charge	$0.00002	$0.00023	$0.00021
	Energy Charge	$0.02358	$0.03490	$0.03234
	Demand Charge	$0.02216	$0.02083	$0.01930
	Transmission Charge	$0.00548	$0.01014	$0.00940
	Bundled Commodity Charge per kWh	**$0.07872**	**$0.09892**	**$0.09167**
Irrigation	Service Availability Charge	$12.04	$12.04	$12.04
	Metering	6.63	6.63	6.63
	Meter Reading	1.69	1.69	1.69
	Billing	1.85	1.85	1.85
	Info & Service	0.79	0.79	0.79
	Bundled Monthly Minimum	**$23.00**	**$23.00**	**$23.00**
	Distribution Delivery Charge	$0.02498	$0.01996	$0.01917
	Transmission Delivery Charge	$0.00002	$0.00041	$0.00039
	Energy Charge	$0.02358	$0.03490	$0.03352
	Demand Charge	$0.02830	$0.04143	$0.03979
	Transmission Charge	$0.01064	$0.01328	$0.01275
	Bundled Commodity Charge per kWh	**$0.08752**	**$0.10998**	**$0.10563**
Security Lights	**Bundled Monthly Minimum:**			
	100 W HPS (Small)	**$5.77**	**$5.77**	**$5.77**
	250 W HPS (Large)	**$7.06**	**$7.06**	**$7.06**
	Distribution Delivery Charge	$0.00000	$0.01631	$0.01631
	Transmission Delivery Charge	$0.00034	$0.00018	$0.00018
	Energy Charge	$0.02358	$0.03490	$0.03490
	Demand Charge	$0.02820	$0.01507	$0.01507
	Transmission	$0.00759	$0.00826	$0.00826
	Base Cost of power Adjustment			$0.00179
	Bundled Commodity Charge per kWh	**$0.05971**	**$0.07472**	**$0.07651**
Street Lights	**Bundled Monthly Minimum**	**$0.00000**	**$0.00000**	**$0.00000**
	Distribution Delivery Charge	$0.02565	$0.02874	$0.02874
	Transmission Delivery Charge	$0.00060	$0.00026	$0.00026
	Energy Charge	$0.02709	$0.03490	$0.03490
	Demand Charge	$0.02236	$0.01913	$0.01913
	Transmission Charge	$0.00759	$0.01526	$0.01526
	Base Cost of power Adjustment			$0.00093
	Bundled Commodity Charge per kWh	**$0.08329**	**$0.09829**	**$0.09922**

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY ELECTRIC COOPERATIVE, INC. FOR A DETERMINATION OF THE FAIR VALUE OF ITS PROPERTY AND FOR AN ORDER SETTING JUST AND REASONABLE RATES	)	DOCKET NO. E-01749A-07-0236

DIRECT

TESTIMONY

OF

PREM K. BAHL

ELECTRIC UTILITIES ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 6, 2007

TABLE OF CONTENTS

Page

INTRODUCTION 1

PURPOSE OF TESTIMONY 3

ENGINEERING EVALUATION 3

COST OF SERVICE STUDY 8

REVIEW PROCESS 8

CONCLUSIONS AND RECOMMENDATIONS 10

EXHIBITS

STAFF ADJUSTED SCHEDULES ..... SCHEDULE G

INTRODUCTION

Q. Please state your name and business address.

A. My name is Prem K. Bahl. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom and in what capacity are you employed?

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer.

Q. Please describe your educational background.

A. I graduated from the South Dakota State University with a Masters degree in Electrical Engineering in May 1972. I received my Professional Engineering ("P.E.") License in the state of Arizona in 1978. My Bachelor of Science degree in Electrical Engineering was from Agra University, India in 1957.

Q. Please describe your pertinent work experience.

A. I was with the Utilities Division Staff ("Staff") of the Commission from 1988 to 1998 as a Utilities Consultant, and have been re-employed at the Commission as an Electric Utilities Engineer since June 2002. During this time period of approximately fifteen years, I conducted engineering evaluations of electric utility rate cases and financing cases. I inspected the utility power plants including the Palo Verde Nuclear Generating Station. I was involved with the development of retail competition in Arizona and of Desert Star, an Independent System Operator for the southwest region. I was Chairman of the System Reliability Working Group, which evaluated the impact of competition on system reliability and recommended the establishment of the Arizona Independent System Administrator ("AZ ISA") as an interim organization until commercial operation of Desert

STAR (now WestConnect as Regional Transmission Operator). Since rejoining the Commission, I have been responsible for reviewing and testifying in several financing and rate cases of cooperatives and electric utilities.

I have reviewed the utilities' load curtailment plans; coordinated with the Commission Consultants to hold stakeholder workshops to report on the second, third and fourth Biennial Transmission Assessments 2002, 2004 and 2006, in the state of Arizona; and am responsible for the compliance of power plant and line siting cases. Recently, I testified in the case of Northern Arizona Energy Project siting case.

From July 2001 to June 2002, I had my own consulting engineering firm, named P. K. Bahl & Associates. During this time, I was involved with deregulation of the electric power industry, formation of Regional Transmission Organizations, (especially the planning), congestion management, business practices and market monitoring activities of the RTO West and the MidWest ISO.

From July 1998 to August 2000, I worked as Chief Engineer at the Residential Utility Consumer Office. During this time period, I performed many of the duties I performed at the Commission. I was also involved with the Distributed Generation Work Group that looked at the impact of development of distributed generation in Arizona on system reliability modifications of interconnection standards currently specified by the jurisdictional utilities. I was a member of the AZ ISA Board of Directors from September 1999 until June 2000. I was involved in the deliberations of the Market Interface Committee of the North American Electric Reliability Council. I also published and presented a number of technical papers at national and international conferences regarding transmission issues and distributed generation.

Prior to my employment with the Commission, I had worked as an electrical engineer with electric utilities and consulting firms in the transmission and generation planning areas for approximately thirty years, including ten years experience at the Punjab State Electricity Board in India from 1960 to 1970.

Q. As part of your assigned duties at the Commission, did you perform Staff's engineering analysis of the application that is the subject of this proceeding?

A. Yes, I did.

Q. Is your testimony herein based on that analysis?

A. Yes, it is.

PURPOSE OF TESTIMONY

Q. What is the purpose of your prefiled testimony?

A. The purpose of my testimony is to discuss Staff's engineering evaluation of the Graham County Electric Cooperative's ("Graham," "Graham Electric" or "Cooperative") system operations and planning, and to discuss Staff's review of Graham's Cost of Service ("COS") study for the bundled rate case, and present the results of this review. Graham Electric's last rate case was filed in Docket No. E-01749A-02-0701 and approved by the Commission via Decision No. 66382 dated October 6, 2003.

ENGINEERING EVALUATION

Q. Did you perform an engineering evaluation of Graham's electrical system?

A. Yes, I did. In response to Graham Electric's rate filing, I inspected the Cooperative's distribution system facilities on August 30 & 31, 2007, and discussed with Graham's officials certain elements of its rate filing, and the Cooperative's Construction Work Plan

("CWP") 2002-2006. I also relied on the responses to Staff's data requests (both written and verbal) received from John Wallace and the Cooperative's officials.

Q. Will you please enumerate the highlights of your inspection of Graham's electric system?

A. Yes, I will. The following provides an account of my inspection of Graham's electrical system.

I visited Graham's offices on August 30 & 31, 2007, and met with Mr. Russ Barney, Finance Manager, and Dennis Kouts, Manager of Engineering. I inspected various substations and distribution system elements accompanied by Mr. Kouts.

A. <u>Graham Electric's Service Area</u>

Graham Electric serves portions of Graham County including the communities of Bonita, Bylas, Cactus Flat, Fort Thomas, Klondyke, Pima, and San Jose, and areas surrounding Safford and Thatcher, all in Arizona.

B. <u>Electric System Description</u>

Graham Electric is a full-requirement customer of Arizona Electric Power Cooperative ("AEPCO"). AEPCO delivers power to the Cooperative at the Dos Condados 230 kV substation. From there, the power is transmitted to Graham's distribution substations over the 69 kV lines owned by the Cooperative.

C. <u>Electric System Characteristics</u>

Graham's system peak load increased from 34,144 KW in 2002 to 42,071 KW in 2007, showing an average annual increase of 4.64 percent over this time period.

Average number of services, including all classes of customers, increased from 7,545 in 2003 to 8,028 in 2006, indicating an average increase of 2.14 percent per year. The level of load growth seems reasonable for the rural type of service territory served by Graham Electric.

No additions were made in the sub transmission system of 69 kV since 1997, which remains at 79 miles. The distribution lines increased from 1,055 miles in 2003 to 1,079 miles in 2006. The increase of 24 miles of new lines includes new service connections provided to new customers. An increase in the system infrastructure development is primarily due to the Cooperative's five year construction work plans, including system improvements and upgrades, and seems to be commensurate with the Cooperative's load growth.

D. **Annual System Losses**

Graham Electric's annual historic system losses are listed below.

2002	8.31%
2003	11.37%
2004	8.24%
2005	8.73%
2006	8.86%

These losses average 9.1 percent per year for the above noted period 2002-2006, and include 2-3 percent of Graham's sub-transmission losses, resulting from AEPCO's delivery point at Dos Condados to Graham's distribution substations. Therefore, the annual distribution system losses average 6-7 percent for the above

period. These losses are well within reasonable limits according to the guidelines provided by the American Public Power Association's Distribution System Loss Evaluation Manual applicable to the electrical systems such as that of the Cooperative's. Typical distribution system loss values indicated in the said Manual range between 6 percent for urban systems to 10 percent for rural systems.

F. Quality of Service

The outages that occur in a utility's system stem from a variety of causes and determine the quality of service to customers. Some of these causes are storm – related; others are relative to switching surges, equipment failure and planned outages. The historical data relative to Graham's distribution system outages is shown in the following table.

Year	No. of Customers	No. of Annual Outage Hours	Avg. Customer Outage Hours per Year
2003	7,545	13,581	1.8
2004	7,666	23,075	3.0
2005	7,799	31,586	4.1
2006	8,028	23,923	3.0
Average Customer Outage Hours per Year			**3.0**

According to the Rural Utilities Service ("RUS") Bulletin 161-5, average customer outage hours per year of five or under are acceptable. The information indicated in the above table shows that the Cooperative's service quality in terms of reliability meets the RUS standard.

F. Distribution System Inspection

During my inspection of Graham's distribution system, it was noted that several system improvements and system upgrades were carried out by the Cooperative, in accordance with the Cooperative's Five Year Construction Work Plan 2002-2006.

In 2004, Graham Electric completed the Thatcher Plant to Hillcrest 8 mile long 12.5 kV line rebuild, which included Gila River crossing. The part of this rebuild on steel poles near the Thatcher Plant Substation was inspected.

The new Cork 69 kV Substation with incoming 69 kV line rebuilt on steel poles was visited. The purpose of the incoming steel poles over several spans was to make the line more accessible by siting along the highway on the other side of the railroad track, and get it out of the brush fire danger to which the old portion of the line was subjected. The transformer at this substation was increased from 5 MVA to 12/16/20 MVA to meet additional demand in the area. The current demand on this substation is 6 MW. Also visited was the new Swift Trail Substation, which is identical to the Cork Substation, both completed in 2005. This substation was built to take some of the load off the Cactus substation that was operating close to its capacity. The Swift Trail double circuit line construction consisted of building approximately 0.7 mile of double circuit three phase line and 0.5 mile of single circuit three phase line. The purpose for this construction was to bring the 3 circuits out of the new Swift Trail substation to serve the prison load, and pick up part of the existing load in the area to relieve the loading on the Cactus Substation.

The system improvements, rebuilding a portion of 69 kV line on steel poles, and new additions has significantly increased the reliability of the system. The steel

poles are more robust at angle points as they do not need to be anchored with guy wires, avoiding preventable outages caused by vehicles hitting into them. The steel poles also replaced some of the old wooden poles that needed replacement in congested areas. It was also noted that the substations were properly maintained, with safety-related equipment installed in the switchgear rooms and 'Danger' signs installed on the fence around the substations. No oil leakage at the substation transformers was detected.

Graham Electric has an ongoing plan to replace 400-500 wooden poles per year that have reached the end of their useful lives. The wooden poles have an average life span of 40 to 50 years, which means that majority of the poles in the Cooperative's service territory would be replaced by the time their life span nears the end, considering that the Cooperative now has approximately 19,000 poles in its service territory.

Graham has an aggressive plan for tree trimming as it has designated two crewmen that attend to this work regularly, besides their other duties. In 2007, Graham hired Asplundh Tree Expert Company to do additional tree trimming in its service territory.

COST OF SERVICE STUDY

REVIEW PROCESS

Q. What does Cost of Service Study ("COS") signify?

A. There are three steps to take in performing a COS study. They are: 1) functionalization; 2) classification; and 3) allocation. First, the COS study enables us to determine the system's Cost of Service by classifying the utility's COS (investments and expenses) by function,

such as customer-related, demand-related, and energy-related functions. Second, the study breaks down COS by customer classes to reflect as closely as possible the COS causation by respective customer classes. Third, the results of the COS study provide a benchmark for the revenues needed from each customer category by appropriately allocating the revenue requirement for each customer class.

Q. Is there a standard COS model?

A. There is no standard methodology for designing a COS study, but it is generally advisable to follow a range of alternatives to identify which allocations are more reasonable than others. For that reason, the COS study should be used as a general guide only and as one of many considerations in designing rates.

Q. What process was used in reviewing the Cooperative's COS study?

A. First, I reviewed the model used by the Cooperative in developing various allocation factors in the bundled COS study. Second, I reviewed the Test Year ended September 30, 2006, rate base, revenues and expenses in the bundled rate case, adjusted by the Cooperative by its Pro Forma adjustments, and matched them with the appropriate schedules contained in the application. Third, I incorporated the changes in the COS study that Staff witness, Gerry Becker, had made to the revenue requirement. These changes related, among others, to fuel adjustor revenue and cost of power.

Q. What models were used by the Cooperative in developing its COS study and how satisfied is Staff with the results obtained by utilizing these models?

A. For the bundled rate case, Graham Electric used the model that was recommended by Staff and approved by the Commission in the last rate case. For the unbundled rate case, the Cooperative did not perform the full fledged COS study, because of the cost of

approximately $10,000. Commission Staff Bill Musgrove will address the unbundled COS study in more detail in his testimony.

The demand related allocation factors are based on 4 Coincident Peak ("4CP") and Average method in the model. Other factors relative to customer-related and energy-related functions appear to be reasonable. I evaluated the model for the bundled rate case and ascertained the reasonableness of the results. The relevant Staff adjusted schedules, G1 thru G18 for the bundled case are included in Exhibit 1.

Q. What is meant by four coincident peaks?

A. Coincident peak means the maximum system demand which occurs at the same time that the AEPCO peak occurs every month. Graham Electric is charged by AEPCO based on its peak coincident with AEPCO's peak. Four coincident peaks are the four monthly peak demands that Graham experiences coincident with AEPCO's peak in the same respective months.

Q. What is meant by non-coincident peak that Graham Electric experiences?

A. Non-coincident peak is the maximum demand experienced by Graham Electric in a specified period of time, such as a month or a year, which occurs at a time other than the time when AEPCO experiences its peak.

CONCLUSIONS AND RECOMMENDATIONS

Q. Based upon your testimony, what are Staff's conclusions and recommendations regarding the engineering evaluation of Graham's electrical system and the COS study?

A. Staff's conclusions and recommendations are as follows:

1. It is Staff's conclusion that Graham Electric:
   a. is operating and maintaining its electrical system properly,
   b. is carrying out system improvements, upgrades and new additions to meet the current and projected load of the Cooperative in an efficient and reliable manner. These improvements, system upgrades and new construction are reasonable and appropriate.
   c. has acceptable level of system losses, consistent with the industry guidelines, and
   d. has a satisfactory record of service interruptions in the historic period from 2003 thru 2006, reflecting satisfactory quality of service.
2. Staff further concludes that Cooperative has used the COS model for the bundled rate filing appropriately and consistent with the model approved by the Commission in the last rate filing by the Cooperative.
3. Staff further concludes that, based on the evaluation of the COS model utilized by the Cooperative, the results are satisfactory, and in compliance with the Commission Order in Decision No. 66382 in that Graham Electric has included Street Light class in the unbundled COS study in this rate filing. In his testimony, John Wallace states that the Cooperative did not do full fledged Unbundled COS study because of the prohibitive costs involved. Plus, the Cooperative's service territory is not yet open to competition. ACC Staff Bill Musgrove will address Graham's unbundled COS in more detail in his testimony.
4. Staff recommends that:
   a. Graham Electric should continue to pursue the wooden pole replacement and tree trimming program, and other necessary system improvements and additions reflected in the Cooperative's 5-year Work Plan 2002-2006.

b. Graham Electric should continue to use the same COS model for the bundled case in future rate cases as used in this rate filing.

Q. Does that conclude your testimony?

A. Yes, it does.

	A	B	C	D	E	F	G	H	I	J
1	GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.									Schedule G-1
2	FULLY ALLOCATED COST OF SERVICE - PRESENT RATES									
3	TEST YEAR ENDED SEPTEMBER 30, 2006									
4	**CATEGORY**	**FERC ACCT #**	**FACTOR CODE**	**TOTAL**	**RESIDENTIAL**	**IRRIGATION**	**SMALL COMMERCIAL**	**LARGE COMMERCIAL**	**SECURITY LIGHTING**	**STREET LIGHTS**
5	OPERATING REVENUES									
6	SUBTOTAL SALES		SUBSALES	13,473,417	6,580,825	1,657,131	2,780,163	2,329,868	113,975	11,456
7	SUBTOTAL OTHER OPERATING REVENUE		SUBOTHER	397,315	192,724	53,411	81,006	67,176	2,664	335
8	TOTAL OPERATING REVENUES			**13,870,732**	**6,773,549**	**1,710,541**	**2,861,168**	**2,397,044**	**116,639**	**11,791**
9	OPERATING EXPENSE									
10	TOTAL ELECTRIC O & M EXPENSE			13,126,922	6,456,133	1,827,162	2,550,605	2,179,160	103,810	10,052
11	TOTAL DEPRECIATION & AMORT EXP			870,555	439,951	138,262	165,070	114,887	12,035	349
12	TOTAL OPERATING EXPENSES			**13,997,477**	**6,896,084**	**1,965,424**	**2,715,676**	**2,294,047**	**115,845**	**10,402**
13	NET OPERATING INCOME			**(126,745)**	**(122,535)**	**(254,883)**	**145,493**	**102,997**	**794**	**1,389**
14	TOTAL PLANT IN SERVICE			29,095,642	14,702,957	4,619,204	5,516,954	3,843,050	401,727	11,752
15	TOTAL ACCUM. DEPR. & AMORT.			10,019,360	5,064,767	1,591,403	1,899,358	1,320,806	139,027	4,001
16	NET RATE BASE			**19,076,282**	**9,638,190**	**3,027,801**	**3,617,596**	**2,522,244**	**262,700**	**7,752**
17	RETURN ON RATE BASE			-0.66%	-1.27%	-8.42%	4.02%	4.08%	0.30%	17.92%
18	NET OPERATING INCOME			(126,745)	(122,535)	(254,883)	145,493	102,997	794	1,389
19	GROSS REVENUE			13,870,732	6,773,549	1,710,541	2,861,168	2,397,044	116,639	11,791
20	RETURN ON REVENUE			-0.91%	-1.81%	-14.90%	5.09%	4.30%	0.68%	11.78%
21	**REVENUE REQUIREMENT - RETURN ON REVENUE BASIS**									
22	CURRENT REVENUE				6,773,549	1,710,541	2,861,168	2,397,044	116,639	11,791
23	NET OPERATING INCOME AT CURRENT RATES				(122,535)	(254,883)	145,493	102,997	794	1,389
24	NET OPERATING INCOME REQUIRED FOR EQUAL RETURN				(61,894)	(15,630)	(26,144)	(21,903)	(1,066)	(108)
25	INCREASED NET OPERATING INCOME REQUIREMENT				60,641	239,253	(171,637)	(124,901)	(1,860)	(1,497)
26	GROSS UP OF INCREASED NET OPERATING INCOME									
27	**REVENUES NEEDED FOR EQUAL RETURN**			**13,860,438**	**6,834,190**	**1,949,794**	**2,689,531**	**2,272,143**	**114,779**	**10,294**
28	**RATIO OF ACTUAL TO EQUAL RETURN REVENUES**				**0.99**	**0.88**	**1.06**	**1.05**	**1.02**	**1.15**

	A	B	C	D	E	F	G	H	I	J
1	GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.									Schedule G-2
2	SUMMARY OF RATE BASE, O&M, DEPRECIATION & ACCUMULATED DEPRECIATION									
3	TEST YEAR ENDED SEPTEMBER 30, 2006									
4	CATEGORY	FERC ACCT #	FACTOR CODE	TOTAL	RESIDENTIAL	IRRIGATION	SMALL COMMERCIAL	LARGE COMMERCIAL	SECURITY LIGHTING	STREET LIGHTS
5	**SUMMARY OF RATE BASE**									
6	TOTAL PRODUCTION PLANT		SUMPRB	-	-	-	-	-	-	1
7	TOTAL TRANSMISSION PLANT		SUMTRB	2,551,563	1,221,188	399,024	508,164	412,557	8,518	2,112
8	TOTAL DISTRIBUTION PLANT		SUMDRB	23,231,767	11,804,481	3,695,507	4,382,316	2,994,950	346,208	8,304
9	TOTAL GENERAL PLANT		SUMGRB	3,071,765	1,551,847	487,813	582,640	405,962	42,261	1,241
10	TOTAL MISCELLANEOUS RATE BASE		SUMMSCRB	240,547	125,440	36,859	43,834	29,580	4,739	94
11	TOTAL PLANT IN SERVICE		SUMRB	**29,095,642**	**14,702,957**	**4,619,204**	**5,516,954**	**3,843,050**	**401,727**	**11,752**
12	**SUMMARY OF ELECTRIC O&M EXPENSES**									
13	TOTAL PRODUCTION EXPENSE		SUMPX	10,144,909	4,801,219	1,384,011	2,040,525	1,864,842	45,276	9,037
14	TOTAL TRANSMISSION EXPENSE		SUMTX	40,340	19,307	6,308	8,034	6,522	135	33
15	TOTAL DISTRIBUTION O & M EXPENSE		SUMDX	1,736,348	898,832	283,381	328,790	219,501	5,253	590
16	BILLING, ASSISTANCE & SALES EXPENSE		SUMSX	357,972	265,336	33,740	32,373	775	25,663	84
17	TOTAL A&G EXPENSE		SUMAGX	825,421	459,237	116,622	137,236	85,253	26,772	300
18	TOTAL ELECTRIC O & M EXPENSE		SUMOMX	**13,104,990**	**6,443,931**	**1,824,063**	**2,546,958**	**2,176,894**	**103,099**	**10,044**
19	**SUMMARY OF DEPRECIATION EXPENSE**									
20	TOTAL PROD PLANT DEPRECIATION EXP.		SUMPDX	-	-	-	-	-	-	1
21	TOTAL TRANS PLANT DEPRECIATION EXP.		SUMTDX	69,969	33,487	10,942	13,935	11,313	234	58
22	TOTAL DIST PLANT DEPRECIATION EXP.		SUMDDX	687,950	349,560	109,433	129,771	88,688	10,252	246
23	GENERAL PLANT DEPRECIATION EXP.		SUMGDX	112,637	56,904	17,887	21,364	14,886	1,550	46
24	TOTAL DEPRECATION AND AMORT. EXPENSE		SUMPTDGDX	**870,555**	**439,951**	**138,262**	**165,070**	**114,887**	**12,035**	**350**
25	**SUMMARY OF ACCUMULATED DEPRECIATION**									
26	TOTAL PROD PLANT ACCUM. DEPRECIATION		SUMPAD	-	-	-	-	-	-	1
27	TOTAL TRANS PLANT ACCUM. DEPRECIATION		SUMTAD	663,748	317,672	103,800	132,191	107,320	2,216	549
28	TOTAL DIST PLANT ACCUM. DEPRECIATION		SUMDAD	7,075,044	3,594,958	1,125,436	1,334,598	912,088	105,435	2,529
29	GENERAL PLANT ACCUM. DEPRECIATION		SUMGAD	2,280,568	1,152,137	362,166	432,569	301,398	31,376	921
30	TOTAL ACCUMULATED DEPRECIATION		SUMAD	**10,019,360**	**5,064,767**	**1,591,403**	**1,899,358**	**1,320,806**	**139,027**	**4,001**

	A	B	C	D	E	F	G	H	I	J	K	L
1					GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.							Schedule G-3
2					REVENUE ALLOCATION							
3					TEST YEAR ENDED SEPTEMBER 30, 2006							
4	**CATEGORY**	**FERC ACCT #**	**FACTOR CODE**	**FORM 7**	**ADJUSTMENTS**	**TOTAL**	**RESIDENTIAL**	**IRRIGATION**	**SMALL COMMERCIAL**	**LARGE COMMERCIAL**	**SECURITY LIGHTING**	**STREET LIGHTS**
5	ALLOCATION OF REVENUES											
6	REVENUES FROM SALES											
7	RESIDENTIAL SALES	440	ASSIGNED	6,580,825		6,580,825	6,580,825					
8	IRRIGATION SALES	444	ASSIGNED	1,657,131		1,657,131		1,657,131				
9	SMALL COMMERCIAL SALES	442	ASSIGNED	2,780,163		2,780,163			2,780,163			
10	LARGE COMMERCIAL SALES	442	ASSIGNED	2,329,868		2,329,868				2,329,868		
11	SECURITY LIGHTING	446	ASSIGNED	113,975		113,975					113,975	
12	STREET LIGHTS		ASSIGNED	11,456		11,456						11,456
13	SUBTOTAL SALES			**13,473,417**	**-**	**13,473,417**	**6,580,825**	**1,657,131**	**2,780,163**	**2,329,868**	**113,975**	**11,456**
14	SALES ALLOCATION FACTOR		SUBSALES			**100.00%**	**48.84%**	**12.30%**	**20.63%**	**17.29%**	**0.85%**	**0.09%**
15	**OTHER OPERATING REVENUES**											
16	WHEELING		TRRB	227,771	(91,696)	136,075	65,126	21,280	27,100	22,002	454	113
17	MISCELLANEOUS		SUBSALES	261,240		261,240	127,598	32,131	53,905	45,174	2,210	222
18	**TOTAL OTHER OPERATING REVENUES**			**489,011**	**(91,696)**	**397,315**	**192,724**	**53,411**	**81,006**	**67,176**	**2,664**	**335**
19	**TOTAL OPERATING REVENUES**			**13,962,428**	**(91,696)**	**13,870,732**	**6,773,549**	**1,710,541**	**2,861,168**	**2,397,044**	**116,639**	**11,791**
20	**REVENUE ALLOCATION FACTOR**		**REV**			**100.00%**	**48.83%**	**12.33%**	**20.63%**	**17.28%**	**0.84%**	**0.09%**

	A	B	C	D	E	F	G	H	I	J	K	L
1	GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.										Schedule G-4	
2	TRANSMISSION & DISTRIBUTION PLANT ALLOCATION											
3	TEST YEAR ENDED SEPTEMBER 30, 2006											
4	**CATEGORY**	**FERC ACCT #**	**FACTOR CODE**	**BALANCE**	**ADJUSTMENTS**	**TOTAL**	**RESIDENTIAL**	**IRRIGATION**	**SMALL COMMERCIAL**	**LARGE COMMERCIAL**	**SECURITY LIGHTING**	**STREET LIGHTS**
5	LAND & LAND RIGHTS-TRANSMISSION	1350.00	P&A4	6,065		6,065	2,903	949	1,208	981	20	5
6	CLEARING LAND & RIGHT OF WAY-TRANSMISSIO	1351.00	P&A4	1,188		1,188	569	186	237	192	4	1
7	STATION EQUIPMENT-TRANSMISSION	1353.00	P&A4	144,717		144,717	69,262	22,631	28,822	23,399	483	120
8	POLES & FIXTURES - TRANSMISSION	1355.00	P&A4	1,643,066		1,643,066	786,378	256,950	327,230	265,664	5,485	1,360
9	OVERHEAD CONDUCTORS & DEVICES - TRANS	1356.00	P&A4	756,527		756,527	362,077	118,309	150,668	122,321	2,526	626
10	**TOTAL TRANSMISSION PLANT RATE BASE**			**2,551,563**	**-**	**2,551,563**	**1,221,188**	**399,024**	**508,164**	**412,557**	**8,518**	**2,112**
11	**TRANSMISSION PLANT ALLOCATION**		**TRRB**			**100.00%**	**47.86%**	**15.64%**	**19.92%**	**16.17%**	**0.33%**	**0.08%**
12	**DISTRIBUTION PLANT IN SERVICE**											
13	LAND & LAND RIGHTS DISTRIBUTION	1360.00	NCP4	47,810		47,810	23,131	8,367	9,433	6,751	110	19
14	STATION EQUIPMENT-DISTRIBUTION	1362.00	NCP4	5,634,888		5,634,888	2,726,159	986,105	1,111,763	795,646	12,960	2,254
15	POLES, TOWERS & FIXTURES-DISTRIBUTION	1364.00	NCP4	6,089,023	(50,923)	6,038,100	2,921,233	1,056,668	1,191,317	852,580	13,888	2,415
16	OVERHEAD CONDUCTORS & DEVICES-DIST	1365.00	NCP4	3,311,876	(37,598)	3,274,278	1,584,096	572,999	646,015	462,328	7,531	1,310
17	UNDERGROUND CONDUIT-DISTRIBUTION	1366.00	NCP4	522,344		522,344	307,322	-	125,314	89,708	-	-
18	UNDERGROUND CONDUCTORS & DEVICES-DIST	1367.00	NCP4	583,584		583,584	343,353	-	140,005	100,225	-	-
19	LINE TRANSFORMERS	1368.00	NCP4	4,854,168	(23,289)	4,830,879	2,337,179	845,404	953,133	682,120	11,111	1,932
20	SERVICES	1369.00	NCP4	1,138,523	(12,032)	1,126,491	838,541	82,907	89,504	1,558	113,607	374
21	METERS	1370.00	NCP4	988,401	(2,010)	986,391	723,467	143,058	115,832	4,034	-	-
22	INSTALLATIONS ON CONSUMERS' PREMISES	1371.00	NCP4	189,009	(2,008)	187,001	-	-	-	-	187,001	-
23	**TOTAL DISTRIBUTION RATE BASE**		**SUMDRB**	**23,359,626**	**(127,859)**	**23,231,767**	**11,804,481**	**3,695,507**	**4,382,316**	**2,994,950**	**346,208**	**8,304**
24	**DISTRIBUTION PLANT ALLOCATION**		**DRB**			**100.00%**	**50.81%**	**15.91%**	**18.86%**	**12.89%**	**1.49%**	**0.04%**

Schedule G-5

GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.
TOTAL PLANT IN SERVICE ALLOCATION
TEST YEAR ENDED SEPTEMBER 30, 2006

	A	B	C	D	E	F	G	H	I	J	K	L
4	**CATEGORY**	**FERC ACCT #**	**FACTOR CODE**	**BALANCE**	**ADJUSTMENTS**	**TOTAL**	**RESIDENTIAL**	**IRRIGATION**	**SMALL COMMERCIAL**	**LARGE COMMERCIAL**	**SECURITY LIGHTING**	**STREET LIGHTS**
5	**ALLOCATION OF TOTAL PRODUCTION, TRANSMISSION AND DISTRIBUTION RATE BASE**											
6	TOTAL PRODUCTION PLANT RATE BASE		SUMPRB									
7	TOTAL TRANSMISSION PLANT RATE BASE	Sch. G-4	SUMTRB	2,551,563	-	2,551,563	1,221,188	399,024	508,164	412,557	8,518	2,112
8	TOTAL DISTRIBUTION PLANT RATE BASE	Sch. G-4	SUMDRB	23,359,626	(127,859)	23,231,767	11,804,481	3,695,507	4,382,316	2,994,950	346,208	8,304
9	**SUBTOTAL PTD RATE BASE**		SUMPTDRB	**25,911,189**	**(127,859)**	**25,783,330**	**13,025,669**	**4,094,532**	**4,890,480**	**3,407,507**	**354,726**	**10,416**
10	**P T D PLANT ALLOCATION**		**PTDRB**	**100.50%**	**-0.50%**	**100.00%**	**50.52%**	**15.88%**	**18.97%**	**13.22%**	**1.38%**	**0.04%**
11	**GENERAL PLANT IN SERVICE**											
12	ORGANIZATION	1301.00	PTDRB	1134.73		1,134.73	573	180	215	150	16	0
13	MISC. INTANGIBLE PLANT	1303.00	PTDRB	1924.99		1,924.99	972	306	365	254	26	1
14	LAND & LAND RIGHTS - GENERAL PLANT	1389.00	PTDRB	50,393.52		50,393.52	25,459	8,003	9,558	6,660	693	20
15	STRUCTURES & IMPROVEMENTS-GENERAL PL/	1390.00	PTDRB	324,366.00		324,366.00	163,869	51,511	61,524	42,868	4,463	131
16	OFFICE FURNITURE & FIXTURES	1391.00	PTDRB	37,802.26		37,802.26	19,098	6,003	7,170	4,996	520	15
17	OFFICE FURNITURE & FIXTURES-COMPUTER	1391.10	PTDRB	56,060.72		56,060.72	28,322	8,903	10,633	7,409	771	23
18	OFFICE EQUIPMENT	1391.20	PTDRB	229,397.85		229,397.85	115,891	36,430	43,511	30,317	3,156	93
19	TRANSPORTATION EQUIPMENT	1392.00	PTDRB	1,688,067.00		1,688,067.00	852,807	268,074	320,186	223,094	23,224	682
20	STORES EQUIPMENT	1393.00	PTDRB	2,586.57		2,586.57	1,307	411	491	342	36	1
21	TOOLS & SHOP EQUIPMENT	1394.00	PTDRB	161,348.00		161,348.00	81,513	25,623	30,604	21,324	2,220	65
22	LABORATORY EQUIPMENT	1395.00	PTDRB	53,135.00		53,135.00	26,844	8,438	10,078	7,022	731	21
23	POWER OPERATED EQUIPMENT	1396.00	PTDRB	188,081.00		188,081.00	95,018	29,868	35,674	24,857	2,588	76
24	COMMUNICATION EQUIPMENT	1397.00	PTDRB	274,315.00		274,315.00	138,583	43,563	52,031	36,253	3,774	111
25	MISC EQUIPMENT	1398.00	PTDRB	3,151.94		3,151.94	1,592	501	598	417	43	1
26	**SUBTOTAL GENERAL PLANT RATE BASE**		SUMGRB	**3,071,765**	**-**	**3,071,765**	**1,551,847**	**487,813**	**582,640**	**405,962**	**42,261**	**1,241**
27	**GENERAL PLANT ALLOCATION**		SUBGRB	**100.00%**	**0.00%**	**100.00%**	**50.52%**	**15.88%**	**18.97%**	**13.22%**	**1.38%**	**0.04%**
28	**TOTAL PLANT IN SERVICE**			**28,982,954**	**(127,859)**	**28,855,095**	**14,577,516**	**4,582,344**	**5,473,120**	**3,813,469**	**396,988**	**11,657**
29	**TOTAL ELECTRIC PLANT ALLOCATION**		PTDGRB	**100.44%**	**-0.44%**	**100.00%**	**50.52%**	**15.88%**	**18.97%**	**13.22%**	**1.38%**	**0.04%**

	A	B	C	D	E	F	G	H	I	J
1				GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.					Schedule G-6	
2				RATE BASE ALLOCATION						
3				TEST YEAR ENDED SEPTEMBER 30, 2006						
4	**CATEGORY**	**FERC ACCT #**	**FACTOR CODE**	**TOTAL**	**RESIDENTIAL**	**IRRIGATION**	**SMALL COMMERCIAL**	**LARGE COMMERCIAL**	**SECURITY LIGHTING**	**STREET LIGHTS**
5	MISCELLANEOUS RATE BASE									
6	MATERIAL & SUPPLIES INVENTORY	1154	PTDGRB	310,273	156,749	49,273	58,851	41,005	4,269	125
7	PREPAYMENTS	Sch. G10	S&W	75,766	42,194	10,691	12,579	7,803	2,472	28
8	WORKING CAPITAL		CUST	-	-	-	-	-	-	-
9	CUSTOMER DEPOSITS	Sch. G-5	PTDRB	(145,492)	(73,502)	(23,105)	(27,596)	(19,228)	(2,002)	(59)
10	TOTAL MISCELLANEOUS RATE BASE			**240,547**	**125,440**	**36,859**	**43,834**	**29,580**	**4,739**	**94**
11	**TOTAL PLANT IN SERVICE**			**29,095,642**	**14,702,957**	**4,619,204**	**5,516,954**	**3,843,050**	**401,727**	**11,751**

	A	B	C	D	E	F	G	H	I	J	K	L
1	GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.										Schedule G-7	
2	PURCHASED POWER AND TRANSMISSION EXPENSES ALLOCATION											
3	TEST YEAR ENDED SEPTEMBER 30, 2006											
4	**CATEGORY**	**FERC ACCT #**	**FACTOR CODE**		**ADJUST.**	**TOTAL**	**RESIDENTIAL**	**IRRIGATION**	**SMALL COMMERCIAL**	**LARGE COMMERCIAL**	**SECURITY LIGHTING**	**STREET LIGHTS**
5	**ALLOCATION OF PRODUCTION, TRANSMISSION AND DISTRIBUTION EXPENSES**											
6	**PURCHASED POWER**	555										
7	DEMAND CHARGES		P&A4	5,347,802	-	5,347,802	2,559,478	836,312	1,065,058	864,674	17,853	4,426
8	ENERGY CHARGES	Sch. G14	NRG	4,012,001	785,107	4,797,108	2,241,741	547,699	975,467	1,000,167	27,422	4,611
9	**TOTAL PURCHASED POWER**			**9,359,803**	**785,107**	**10,144,909**	**4,801,219**	**1,384,011**	**2,040,525**	**1,864,842**	**45,276**	**9,037**
10	**PURCHASED POWER FACTOR**		**PX**	**92.26%**	**7.74%**	**100.00%**	**47.33%**	**13.64%**	**20.11%**	**18.38%**	**0.45%**	**0.09%**
11												
12	**TRANSMISSION EXPENSES**											
13	STATION EXPENSES	1562.00	TRRB	1,422		1,422	681	222	283	230	5	1
14	OPERATIONS-TRANSMISSION LINES	1563.00	TRRB	33,015		33,015	15,801	5,163	6,575	5,338	110	27
15	PATROLLING LINES-TRANSMISSION	1563.10	TRRB	945		945	452	148	188	153	3	1
16	MAINTENANCE OF LINES-TRANSS	1571.00	TRRB	4,958		4,958	2,373	775	987	802	17	4
17	**TOTAL TRANSMISSION EXPENSE**			**40,340**	**-**	**40,340**	**19,307**	**6,308**	**8,034**	**6,522**	**135**	**33**
18	**TRANSMISSION EXPENSE FACTOR**		**TX**	**100.00%**	**0.00%**	**100.00%**	**47.86%**	**15.64%**	**19.92%**	**16.17%**	**0.33%**	**0.08%**

	A	B	C	D	E	F	G	H	I	J	K	L	M
1				GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.							Schedule G-8		
2				DISTRIBUTION OPERATION & MAINTENANCE EXPENSE ALLOCATION									
3				TEST YEAR ENDED SEPTEMBER 30, 2006									
4	CATEGORY	FERC ACCT #	FACTOR CODE	BALANCE	ADJUSTM ENTS	TOTAL	RESIDENTIAL	IRRIGATION	SMALL COMMERCIAL	LARGE COMMERCIAL	SECURITY LIGHTING	STREET LIGHTS	
5	**DISTRIBUTION EXPENSE**												
6	**OPERATION**												
7	OPERATIONS-SUPERVISION	1580.00	SUBO	72,956.27	-	72,956	42,817	11,251	12,275	6,503	93	16	
8	SUBSTATION OPERATIONS	1582.00	362D	41,148.30	-	41,148	19,908	7,201	8,119	5,810	95	16	Sch. G-15
9	OPERATION -LINES	1583.00	3645D	143,533.04	(1,433.00)	142,100	68,748	24,868	28,036	20,065	327	57	Sch. G-15
10	PATROLLING LINES	1583.10	3645D	2,323.72	-	2,324	1,124	407	458	328	5	1	Sch. G-15
11	CHNGOUT-LINES/TRANS	1583.20	3645D	98.00	-	98	47	17	19	14	0	0	Sch. G-15
12	UNDERGROUND LINE EXPENSE	1584.00	366D	17,242.01	-	17,242	10,144	-	4,136	2,961	-	-	Sch. G-16
13	METER EXPENSE	1586.00	370D	17,692.26	-	17,692	12,976	2,566	2,078	72	-	-	Sch. G-16
14	METER INSPEC & TESTING	1586.10	370D	22,351.75	-	22,352	16,394	3,242	2,625	91	-	-	Sch. G-16
15	METER INSTALL & REMOVAL	1586.20	370D	90,391.04	-	90,391	66,297	13,110	10,615	370	-	-	Sch. G-16
16	CUSTOMER INSTALLATION EXPENSE	1587.00	369D	18,830.74	-	18,831	14,017	1,386	1,496	26	1,899	6	Sch. G-16
17	BLUE STAKE	1588.10	SUBO	37,888.49	-	37,888	22,236	5,843	6,375	3,377	49	8	
18	**SUBTOTAL DISTRIBUTION EXPENSE**			**464,455.62**	**(1,433.00)**	**463,023**	**274,710**	**69,890**	**76,232**	**39,617**	**2,468**	**105**	
19	**SUBTOTAL OPERATION EXPENSE**			**334,780**	**(1,433)**	**333,347**	**195,639**	**51,410**	**56,086**	**29,711**	**427**	**74**	
20	**DISTRIBUTION OPERATION SUBT FACTOR**		**SUBO**	**100.43%**	**-0.43%**	**100.0%**	**58.69%**	**15.42%**	**16.83%**	**8.91%**	**0.13%**	**0.02%**	
21	**MAINTENANCE**												
22	MAINTENANCE-SUPERVISION	1590.00	SUBD	36,741.32	-	36,741	18,009	6,160	7,287	5,190	80	14	
23	SUBSTATION MAINTENANCE	1592.00	362D	66,580.22	-	66,580	32,212	11,652	13,136	9,401	153	27	Sch. G-15
24	OVERHEAD LINE MAINTENANCE	1593.00	3645D	440,472.17	-	440,472	213,100	77,083	86,905	62,195	1,013	176	Sch. G-15
25	DD LIGHT MAINTENANCE	1593.01	3645D	30,720.93	-	30,721	14,863	5,376	6,061	4,338	71	12	Sch. G-15
26	OVERHEAD PREVENT. LINE MAINT	1593.02	3645D	90,731.75	-	90,732	43,896	15,878	17,901	12,811	209	36	Sch. G-15
27	RAPTOR PROTECTION	1593.03	3645D	6,494.45	-	6,494	3,142	1,137	1,281	917	15	3	Sch. G-15
28	REGS/RECLOS/CAPACITORS	1593.10	3645D	68,180.04	-	68,180	32,986	11,932	13,452	9,627	157	27	Sch. G-15
29	TREE TIM & R/W CLEAR	1593.20	3645D	63,326.02	-	63,326	30,637	11,082	12,494	8,942	146	25	Sch. G-15
30	CHNGOUTS-POLE/X-ARM/ETC	1593.30	3645D	3,116.45	-	3,116	1,508	545	615	440	7	1	Sch. G-15
31	HARDWARE TIGHTENING	1593.40	3645D	1,247.71	-	1,248	604	218	246	176	3	0	Sch. G-15
32	TROUBLE CALLS-LOCATE & CLEAR	1593.50	3645D	254,826.85	-	254,827	123,285	44,595	50,277	35,982	586	102	Sch. G-15
33	STANDBY	1593.60	3645D	59,137.90	-	59,138	28,611	10,349	11,668	8,350	136	24	Sch. G-15
34		1593.70	3645D	85,537.25	-	85,537	41,383	14,969	16,876	12,078	197	34	Sch. G-15
35	MAINT OF UNDERGROUND LINES	1594.00	3667D	50,036.21	-	50,036	29,439	-	12,004	8,593	-	-	Sch. G-16
36	PCB TEST & OIL REMOVAL	1595.10	368D	5,450.42	-	5,450	2,637	954	1,075	770	13	2	Sch. G-16
37	TRANSFORMER MAINTENANCE	1595.20	368D	221.60	-	222	107	39	44	31	1	0	Sch. G-16
38	METER MAINTENANCE	1597.00	370D	10,503.83	-	10,504	7,704	1,523	1,233	43	-	-	Sch. G-16
39	**DISTRIBUTION EXPENSE SUBTOTAL FACTOR**			**1,273,325.12**	**-**	**1,273,325**	**624,122**	**213,491**	**252,558**	**179,884**	**2,785**	**484**	
40	**SUBD FACTOR TOTAL**			**1,236,584**	**-**	**1,236,584**	**606,113**	**207,331**	**245,271**	**174,694**	**2,705**	**470**	
41	**DISTRIBUTION EXPENSE SUBT FACTOR**		**SUBD**	**100.00%**	**0.00%**	**100.0%**	**49.02%**	**16.77%**	**19.83%**	**14.13%**	**0.22%**	**0.04%**	
42	**TOTAL DISTRIBUTION O & M EXPENSE**		**SUMDX**	**1,737,781**	**(1,433)**	**1,736,348**	**898,832**	**283,381**	**328,790**	**219,501**	**5,253**	**590**	
43	**DISTRIBUTION EXPENSE FACTOR**		**DX**	**100.08%**	**-0.08%**	**100.0%**	**51.77%**	**16.32%**	**18.94%**	**12.64%**	**0.30%**	**0.03%**	

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.										Schedule G-9		
2	BILLING AND CUSTOMER ASSISTANCE EXPENSE ALLOCATION												
3	TEST YEAR ENDED SEPTEMBER 30, 2006												
4	CATEGORY	FERC ACCT #	FACTOR CODE	BALANCE	ADJUST MENTS	TOTAL	RESIDENTIAL	IRRIGATION	SMALL COMMERCIAL	LARGE COMMERCIAL	SECURITY LIGHTING	STREET LIGHTS	
5	**BILLING AND CUSTOMER ASSISTANCE EXPENSE**												
6	**METER READING**												
7	METER READING EXPENSE	1902.00	CUST3	103,503.72	-	103,504	75,915	15,011	12,154	423	-	-	
8	**TOTAL METER READING EXPENSE**			**103,503.72**	**-**	**103,504**	**75,915**	**15,011**	**12,154**	**423**	**-**	**-**	
9	**ALLOCATION FACTOR**			**100.00%**	**0.00%**	**100.00%**	**73.34%**	**14.50%**	**11.74%**	**0.41%**	**0.00%**	**0.00%**	
10	**BILLING AND CONSUMER RECORDS**												
11	CONSUMER RECORDS & COLL EXP	1903.00	CUST2	(34,248.60)	-	(34,249)	(25,494)	(2,521)	(2,721)	(47)	(3,454)	(11)	Sch. G-14
12	NEW ACCOUNTS/CLOSED ACCOUNT	1903.01	CUST2	25,585.51	-	25,586	19,045	1,883	2,033	35	2,580	8	Sch. G-14
13	CASHIERING	1903.02	CUST2	74,314.96	-	74,315	55,319	5,469	5,905	103	7,495	25	Sch. G-14
14	BILLING	1903.03	CUST2	24,679.81	-	24,680	18,371	1,816	1,961	34	2,489	8	Sch. G-14
15	DELINQUENT ACCOUNTS	1903.07	CUST2	20,707.89	-	20,708	15,415	1,524	1,645	29	2,088	7	Sch. G-14
16	TROUBLE CALLS	1903.09	CUST2	563.50	-	564	419	41	45	1	57	0	Sch. G-14
17	CASH - OVER & SHORT	1903.10	CUST2	144.88	-	145	108	11	12	0	15	0	Sch. G-14
18	LATE CHARGES	1903.20	CUST2		-	-	-	-	-	-	-	-	Sch. G-14
19	UNCOLLECTIBLE ACCOUNTS	1904.00	CUST	27,420.90	-	27,421	20,412	2,018	2,179	38	2,765	9	Sch. G-14
20	MISC WRITE-OFFS EXPENSE	1904.10	CUST	7.99	-	8	6	1	1	0	1	0	Sch. G-14
21	**TOTAL BILLING AND CUSTOMER RECORDS**			**139,176.84**	**-**	**139,177**	**103,601**	**10,243**	**11,058**	**193**	**14,036**	**46**	
22	**ALLOCATION FACTOR**		SUBB	**100.00%**	**0.00%**	**100.00%**	**74.44%**	**7.36%**	**7.95%**	**0.14%**	**10.09%**	**0.03%**	
23	**ACCOUNTING**												
24	ACCOUNTS PAYABLE	1903.04	CUST	11,600.96	-	11,601	8,636	854	922	16	1,170	4	Sch. G-14
25	PAYROLL PREPARATION	1903.05	CUST	20,892.91	-	20,893	15,552	1,538	1,660	29	2,107	7	Sch. G-14
26	GENERAL LEDGER	1903.06	CUST	12,462.37	-	12,462	9,277	917	990	17	1,257	4	Sch. G-14
27	FILING	1903.08	CUST	3,303.54	-	3,304	2,459	243	262	5	333	1	Sch. G-14
28	WORK ORDERS	1903.11	CUST	1,968.69	-	1,969	1,465	145	156	3	199	1	Sch. G-14
29	CAPITAL CREDITS	1903.13	CUST		-	-	-	-	-	-	-	-	Sch. G-14
30	INVENTORY CLEARING	1903.14	CUST	3,604.79	-	3,605	2,683	265	286	5	364	1	Sch. G-14
31	RATE RELATED	1903.17	CUST	4,525.44	-	4,525	3,369	333	360	6	456	2	Sch. G-14
32	**TOTAL ACCOUNTING**			**58,358.70**	**-**	**58,359**	**43,441**	**4,295**	**4,637**	**81**	**5,885**	**19**	
33	**ALLOCATION FACTOR**			**100.00%**	**0.00%**	**100.00%**	**74.44%**	**7.36%**	**7.95%**	**0.14%**	**10.09%**	**0.03%**	
34	**CUSTOMER RELATIONS**												
35	CUSTOMER RELATIONS	1903.15	CUST	37,517.49	-	37,517	27,927	2,761	2,981	52	3,784	12	Sch. G-14
36	FAIR TIME	1903.16	CUST	3,311.34	-	3,311	2,465	244	263	5	334	1	Sch. G-14
37	CONSUMER MEETINGS	1903.18	CUST	7,662.95	-	7,663	5,704	564	609	11	773	3	Sch. G-14
38	SCHOLARSHIPS	1903.19	CUST	8,440.70	-	8,441	6,283	621	671	12	851	3	Sch. G-14
39	**TOTAL CUSTOMER RELATIONS**			**56,932.48**	**-**	**56,932**	**42,380**	**4,190**	**4,523**	**79**	**5,742**	**19**	
40	**ALLOCATION FACTOR**			100.00%	0.00%	**100.00%**	**74.44%**	**7.36%**	**7.95%**	**0.14%**	**10.09%**	**0.03%**	
41	.		SUMSX	**357,972**	**-**	**357,972**	**265,336**	**33,740**	**32,373**	**775**	**25,663**	**84**	
42	**BILLING AND CUSTOMER ASSISTANCE FACTOR**		SAX	**100.00%**	**0.00%**	**100.00%**	**74.12%**	**9.43%**	**9.04%**	**0.22%**	**7.17%**	**0.02%**	
43	**TOTAL DIST O&M, BILLING & ASST EXP**		SUMDSX	**2,095,752**	**(1,433)**	**2,094,319**	**1,164,168**	**317,121**	**361,163**	**220,276**	**30,917**	**674**	
44													
45				357,971.74									

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.												
2	SUMMARY OF PRODUCTION, TRANSMISSION, DISTRIBUTION & SALES EXPENSE										Schedule G-10		
3	TEST YEAR ENDED SEPTEMBER 30, 2006												
4	CATEGORY	FERC ACCT #	FACTOR CODE	BALANCE	ADJUSTMENTS	TOTAL	RESIDENTIAL	IRRIGATION	SMALL COMMERCIAL	LARGE COMMERCIAL	SECURITY LIGHTING	STREET LIGHTS	
5	**SUMMARY OF PRODUCTION, TRANSMISSION, DISTRIBUTION & SALES EXPENSE**												
6	TOTAL PRODUCTION EXPENSE		SUMPX	9,359,803	785,107	10,144,909	4,801,219	1,384,011	2,040,525	1,864,842	45,276	9,037	Sch. G-7
7	TOTAL TRANSMISSION EXPENSE		SUMTX	40,340	-	40,340	19,307	6,308	8,034	6,522	135	33	Sch. G-7
8	TOTAL DISTRIBUTION O&M EXPENSE		SUMDX	464,456	(1,433)	463,023	274,710	69,890	76,232	39,617	2,468	105	Sch. G-8
9	TOTAL PTD EXPENSE		SUMPTDX	**9,864,598**	**783,674**	**10,648,272**	**5,095,236**	**1,460,210**	**2,124,791**	**1,910,981**	**47,879**	**9,175**	
10	PTD ALLOCATION FACTOR		PTDX	**92.64%**	**7.36%**	**100.00%**	**47.85%**	**13.71%**	**19.95%**	**17.95%**	**0.45%**	**0.09%**	
11	BILLING, ASSISTANCE & SALES EXPENSE		SUMSX	357,972	-	357,972	265,336	33,740	32,373	775	25,663	84	Sch. G-9
12	TOTAL PTDS EXPENSE		SUMPTDSX	**10,222,570**	**783,674**	**11,006,243**	**5,360,572**	**1,493,949**	**2,157,164**	**1,911,756**	**73,542**	**9,260**	
13	PTDS ALLOCATION FACTOR		PTDSX	**92.88%**	**7.12%**	**100.00%**	**48.70%**	**13.57%**	**19.60%**	**17.37%**	**0.67%**	**0.08%**	
14	PURCHASED POWER EXPENSE		SUMPPF	9,359,803	785,107	10,144,909	4,801,219	1,384,011	2,040,525	1,864,842	45,276	9,037	
15	TOTAL OF O&M LESS PURCHASED POWER		+OM-PPF	**862,767**	**(1,433)**	**861,334**	**559,353**	**109,938**	**116,639**	**46,914**	**28,266**	**223**	
16	O&M - PURCHASED POWER ALLOCATION		OM-PPF	**100.17%**	**-0.17%**	**100.00%**	**64.94%**	**12.76%**	**13.54%**	**5.45%**	**3.28%**	**0.03%**	
17	**DEVELOPMENT OF SALARY AND WAGE FACTOR**												
18	TRANSMISSION		TRRB	2,148	-	2,148	1,028	336	428	347	7	2	Sch. G-4
19	DISTRIBUTION		DRB	498,775	-	498,775	253,437	79,341	94,086	64,300	7,433	178	Sch. G-4
20	CUSTOMER SERVICE		CUST	182,273	-	182,273	135,681	13,415	14,482	252	18,382	61	Sch. G-14
21	ADMINISTRATIVE AND GENERAL		PTDRB	187,231	-	187,231	94,589	29,733	35,513	24,744	2,576	76	Sch. G-5
22	TOTAL SALARY AND WAGE EXPENSE			**870,427**	**-**	**870,427**	**484,734**	**122,825**	**144,510**	**89,644**	**28,398**	**316**	
23	SALARY AND WAGE FACTOR		S&W	**100.00%**	**0.00%**	**100.00%**	**55.69%**	**14.11%**	**16.60%**	**10.30%**	**3.26%**	**0.04%**	
24	TOTAL P T D S&W EXPENSE			688,154	-	688,154	349,053	109,410	130,027	89,392	10,016	256	
25	P T D S&W FACTOR		S&WPTD	**100.00%**	**0.00%**	**100.00%**	**50.72%**	**15.90%**	**18.90%**	**12.99%**	**1.46%**	**0.04%**	

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.										Schedule G-11		
2	ADMINISTRATIVE & GENERAL EXPENSE ALLOCATION												
3	TEST YEAR ENDED SEPTEMBER 30, 2006												
4	CATEGORY	FERC ACCT #	FACTOR CODE	BALANCE	ADJUST MENTS	TOTAL	RESIDENTIAL	IRRIGATION	SMALL COMMERCIAL	LARGE COMMERCIAL	SECURITY LIGHTING	STREET LIGHTS	
6	**ADMINISTRATIVE AND GENERAL EXPENSES**												
7	ADMIN & GENERAL SALARIES	1920.00	S&W	245,219	-	245,219	136,561	34,603	40,712	25,255	8,000	89	Sch. G-10
8	EMPLOYEES MEETINGS	1920.10	S&W	10,649	-	10,649	5,930	1,503	1,768	1,097	347	4	Sch. G-10
9	OFFICE SUPPLIES & EXP	1921.00	S&W	86,030	-	86,030	47,909	12,140	14,283	8,860	2,807	31	Sch. G-10
10	OUTSIDE SERVICES EMPLOYED	1923.00	S&W	73,720	-	73,720	41,054	10,403	12,239	7,592	2,405	27	Sch. G-10
11	PROPERTY INSURANCE	1924.00	PTDGRB	8,385	-	8,385	4,236	1,332	1,590	1,108	115	3	Sch. G-5
12	INJURIES & DAMAGES INS.	1925.00	S&W	43,968	-	43,968	24,485	6,204	7,300	4,528	1,434	16	Sch. G-10
13	EMPLOYEE PENSION BENEFITS	1926.00	S&W	6,254	-	6,254	3,483	882	1,038	644	204	2	Sch. G-10
14	EDUCATION & TRAINING	1926.10	S&W	42,426	-	42,426	23,627	5,987	7,044	4,369	1,384	15	Sch. G-10
15	DIRECTORS EDUCATION	1926.11	S&W	31,357	-	31,357	17,463	4,425	5,206	3,229	1,023	11	Sch. G-10
16	SAFETY EDUCATION	1926.20	S&W	41,677	-	41,677	23,210	5,881	6,919	4,292	1,360	15	121,715
17	MEDICAL CLAIMS	1926.30	S&W	33	-	33	18	5	5	3	1	0	Sch. G-10
18	REGULATORY COMMISSION EXP.	1928.00	S&W	25,162	12,000	37,162	20,695	5,244	6,170	3,827	1,212	14	Sch. G-10
19	MISC GENERAL EXPENSE	1930.00	S&W	103,601	-	103,601	57,694	14,619	17,200	10,670	3,380	38	Sch. G-10
20	DIRECTORS FEES	1930.01	S&W	26,438	-	26,438	14,723	3,731	4,389	2,723	863	10	Sch. G-10
21	PUBLICATIONS	1930.10	S&W		-	-	-	-	-	-	-	-	Sch. G-10
22	RENTS	1931.00	S&W	8,268	-	8,268	4,604	1,167	1,373	851	270	3	Sch. G-10
23	MAINT-GENERAL PLANT	1932.00	SUBGRB	12,411	-	12,411	6,911	1,751	2,060	1,278	405	5	Sch. G-5
24	MAINTENANCE-BUILDINGS	1932.10	SUBGRB	23,425	-	23,425	13,045	3,305	3,889	2,412	764	9	Sch. G-5
25	MAINTENANCE-GRNDS/YARDS	1932.20	SUBGRB	24,398	-	24,398	13,587	3,443	4,051	2,513	796	9	Sch. G-5
26	TOTAL ADMIN. & GENERAL EXP.		SUMAGX	**813,421**	**12,000**	**825,421**	**459,237**	**116,622**	**137,236**	**85,253**	**26,772**	**300**	
27	ALLOCATION FACTOR			**98.55%**	**1.45%**	**100.00%**	**55.64%**	**14.13%**	**16.63%**	**10.33%**	**3.24%**	**0.04%**	
28	SUBTOTAL A&G OPERATIONS			**753,188**	**12,000**	**765,187**	**425,694**	**108,123**	**127,236**	**79,050**	**24,807**	**278**	
29	A&G EXPENSE ALLOCATION	**SUBAGX**		**98.43%**	**1.57%**	**100.00%**	**55.63%**	**14.13%**	**16.63%**	**10.33%**	**3.24%**	**0.04%**	
30	INTEREST EXPENSE - OTHER			21932		21,932	12,201	3,099	3,647	2,266	711	8	
31	TOTAL ELECTRIC O & M EXPENSE		SUMOMX	**12,331,248**	**795,674**	**13,126,922**	**6,456,133**	**1,827,162**	**2,550,605**	**2,179,160**	**103,810**	**10,052**	
32	TOTAL O&M EXPENSE ALLOCATION		**O&MX**	**93.94%**	**6.06%**	**100.00%**	**49.18%**	**13.92%**	**19.43%**	**16.60%**	**0.79%**	**0.08%**	

	A	B	C	D	E	F	G	H	I	J	K	L	M
1											Schedule G-12		
2				GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.									
3				DEPRECIATION EXPENSE ALLOCATION									
				TEST YEAR ENDED SEPTEMBER 30, 2006									
4	**CATEGORY**	**FERC ACCT #**	**FACTOR CODE**	**BALANCE**	**ADJUST MENTS**	**TOTAL**	**RESIDENTIAL**	**IRRIGATION**	**SMALL COMMERCIAL**	**LARGE COMMERCIAL**	**SECURITY LIGHTING**	**STREET LIGHTS**	
5													
6	DEPREC- PRODUCTION PLANT					-	-	-	-	-	-	1	
7	DEPREC -TRANSMISSION PLAN	1403.50	TRRB	69,969	-	69,969	33,487	10,942	13,935	11,313	234	58	Sch. G-4
8	DEPREC -DISTRIBUTION PLAN	1403.60	DRB	670,879	17,071	687,950	349,560	109,433	129,771	88,688	10,252	246	Sch. G-4
9	TOTAL P T D DEPRECIATION		SUMPTDDX	**740,848**	**17,071**	**757,919**	**383,047**	**120,375**	**143,706**	**100,001**	**10,486**	**305**	
10	PT D DEPRECIATION EXP. ALLOCATION		PTDDX	**97.75%**	**2.25%**	**100.00%**	**50.54%**	**15.88%**	**18.96%**	**13.19%**	**1.38%**	**0.04%**	
11													
12	**GENERAL PLANT**												
13	AMORT-DIGGER TRUCK	1403.61	SUMGRB	5,873	-	5,873	2,967	933	1,114	776	81	2	Sch. G-5
14	DEPREC-GENERAL PLANT	1403.70	SUMGRB	106,763	-	106,763	53,937	16,955	20,250	14,110	1,469	43	Sch. G-5
15	AMORT-VERSA LIFT TRUCK	1403.91	SUMGRB			-	-	-	-	-	-	-	Sch. G-5
16	TOTAL GENERAL PLANT		SUBGDX	**112,637**	**-**	**112,637**	**56,904**	**17,887**	**21,364**	**14,886**	**1,550**	**46**	
17	TOTAL DEPR AND AMORT EXPENSE		SUMTDGDX	**853,484**	**17,071**	**870,555**	**439,951**	**138,262**	**165,070**	**114,887**	**12,035**	**349**	
18	ALLOCATION FACTOR			**98.04%**	**1.96%**	**100.00%**	**50.54%**	**15.88%**	**18.96%**	**13.20%**	**1.38%**	**0.04%**	

	A	B	C	D	E	F	G	H	I	J	K
1	GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.								Schedule G-13		
2	ACCUMULATED DEPRECIATION EXPENSE ALLOCATION										
3	TEST YEAR ENDED SEPTEMBER 30, 2006										
4	**CATEGORY**	**FERC ACCT #**	**FACTOR CODE**	**TOTAL**	**RESIDENTIAL**	**IRRIGATION**	**SMALL COMMERCIAL**	**LARGE COMMERCIAL**	**SECURITY LIGHTING**	**STREET LIGHTS**	
5	**SUMMARY OF PROVISION FOR ACCUMULATED DEPRECIATION**										
6	TOTAL PROD PLANT ACCUM DEPREC		SUMPAD	-	-	-	-	-	-	1	
7	ACCUM PROV FOR DEPREC TRANS	1108.50	TRRB	663,748	317,672	103,800	132,191	107,320	2,216	549	Sch. G-4
8	ACCUM PROV FOR DEPREC DIST	1108.60	DRB	7,075,044	3,594,958	1,125,436	1,334,598	912,088	105,435	2,529	Sch. G-4
9	TOTAL P T D ACCUM DEPREC		SUMPTDAD	**7,738,792**	**3,912,630**	**1,229,236**	**1,466,789**	**1,019,407**	**107,651**	**3,079**	
10	PTD ACCUMULATED DEPR ALLOCATION		PTDAD	**100.00%**	**50.56%**	**15.88%**	**18.95%**	**13.17%**	**1.39%**	**0.04%**	
11	**OTHER PROVISION FOR ACCUMULATED DEPRECIATION AND AMORTIZATION**										
12	GEN PLANT ACCUM DEPRECIATION		SUBGRB	2,129,932	1,076,036	338,245	403,997	281,490	29,304	860	Sch. G-5
13	GEN PLANT ACCUM AMORTIZATION			150,636	76,101	23,922	28,572	19,908	2,072	61	Sch. G-5
14	TOTAL OTHER ACCUM DEPRECIATION AND AMORT			**2,280,568**	**1,152,137**	**362,166**	**432,569**	**301,398**	**31,376**	**921**	
15	TOTAL ACCUMULATED DEPRECIATION AND AMORT		SUMAD	**10,019,360**	**5,064,767**	**1,591,403**	**1,899,358**	**1,320,806**	**139,027**	**4,001**	

	A	B	C	D	E	F	G	H	I	J	K
1				GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.					Schedule G-14		
2				ALLOCATION FACTORS							
3				TEST YEAR ENDED SEPTEMBER 30, 2006							
4	CATEGORY	FERC ACCT #	FACTOR CODE	TOTAL	RESIDENTIAL	IRRIGATION	SMALL COMMERCIAL	LARGE COMMERCIAL	SECURITY LIGHTING	STREET LIGHTS	
5	CUSTOMER COUNT		CUST	9,036	6,726	665	718	13	911	3	
6	CUSTOMER ALLOCATION FACTOR			100.00%	74.43%	7.36%	7.95%	0.14%	10.09%	0.03%	
7	ENERGY SALES IN KWH		NRG	133,903,331	62,574,485	15,288,123	27,228,553	27,918,020	765,450	128,700	
8	ENERGY ALLOCATION FACTOR			100.00%	46.73%	11.42%	20.33%	20.85%	0.57%	0.10%	
9	SYSTEM COINCIDENT PEAK (12 MONTH) (KW)		CP1	23,960	12,064	3,028	5,263	3,502	88	15	
10	12 CP ALLOCATION FACTOR			100.00%	45.57%	14.24%	20.54%	19.10%	0.41%	0.14%	
11	SYSTEM COINCIDENT PEAK (1 MONTH) (KW)		CP2	36,968	17,796	8,122	6,553	4,405	79	13	
12	1 CP ALLOCATION FACTOR			100.00%	46.74%	19.17%	19.57%	14.09%	0.32%	0.11%	
13	NON-COINCIDENT PEAK (KW)		NCP4	34,787	16,831	6,088	6,863	4,913	79	13	
14	NCP ALLOCATION FACTOR			100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%	
15	SYSTEM LOAD FACTOR FOR AED CALC			43.94%	20.53%	5.02%	8.93%	9.16%	0.25%	0.04%	43.94%
16	AVERAGE DEMAND (KW)			15,286	7,143	1,745	3,108	3,187	87	15	
17	EXCESS DEMAND (KW)			19,501	9,688	4,343	3,755	1,726	(8)	(2)	
18	EXCESS DEMAND ALLOCATION FACTOR			56.06%	27.85%	12.48%	10.79%	4.96%	-0.02%	0.00%	56.06%
19	AED ALLOCATION FACTOR		AED	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%	
20	PEAK AND AVERAGE (12 NCP)		P&A12	100.00%	48.43%	12.04%	21.08%	17.91%	0.43%	0.11%	
21	PEAK AND AVERAGE (4 NCP)		P&A4	100.00%	47.86%	15.64%	19.92%	16.17%	0.33%	0.08%	
22	PEAK AND AVERAGE (1 NCP)		P&A1	100.00%	47.39%	18.89%	18.32%	15.03%	0.30%	0.07%	
23	NCP RESIDENTIAL AND SECONDARY - UG USERS			28,607	16,831		6,863	4,913			
24	ALLOCATION FACTORS		NCP2	100%	58.84%	0.00%	23.99%	17.17%	0.00%	0.00%	
25	**DEVELOPMENT OF WEIGHTED CUSTOMER COUNT ALLOCATION FACTORS**										
26	**CUSTOMER ACCOUNTS**				1.00	1.00	1.00	1.00	1.00	1.00	
27	WEIGHTING FACTOR			9,036	6,726	665	718	13	911	3	
28	WEIGHTED CUSTOMERS		CUST	100%	74.44%	7.36%	7.95%	0.14%	10.09%	0.03%	
29	CUSTOMER ACCOUNTS										
30	**SERVICES**										
31	WEIGHTING FACTOR				1.00	1.00	1.00	1.00	1.00	1.00	
32	WEIGHTED CUSTOMERS			9,036	6,726	665	718	13	911	3	
33	CUSTOMER ACCOUNTS		CUST1	100%	74.44%	7.36%	7.95%	0.14%	10.09%	0.03%	
34	**ACCOUNTING EXPENSE**										
35	WEIGHTING FACTOR				1.00	1.00	1.00	1.00	1.00	1.00	
36	WEIGHTED CUSTOMERS			9,036	6,726	665	718	13	911	3	
37	CUSTOMER ACCOUNTS		CUST2	100%	74.44%	7.36%	7.95%	0.14%	10.09%	0.03%	
38	**METER READING EXPENSE**										
39	WEIGHTING FACTOR				1.00	2.00	1.50	3.00			
40	WEIGHTED CUSTOMERS			9,170	6,726	1,330	1,077	38	-		
41	CUSTOMER ACCOUNTS		CUST3	100%	73.34%	14.50%	11.74%	0.41%	0.00%	0.00%	
42	**DISTRIBUTION METERS**										
43	WEIGHTING FACTOR				1.00	1.00	1.00	1.00			
44	WEIGHTED CUSTOMERS			8,121	6,726	665	718	13	-		
45	CUSTOMER ACCOUNTS		CUST4	100%	82.82%	8.19%	8.84%	0.15%	0.00%	0.00%	

	A	B	C	D	E	F	G	H	I	J
1	GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.								Schedule G-15	
2	DISTRIBUTION PLANT ALLOCATION FACTORS									
3	TEST YEAR ENDED SEPTEMBER 30, 2006									
4	CATEGORY	FERC ACCT #	FACTOR CODE	TOTAL	RESIDENTIAL	IRRIGATION	SMALL COMMERCIAL	LARGE COMMERCIAL	SECURITY LIGHTING	STREET LIGHTS
5	DEVELOPMENT OF DISTRIBUTION COST ALLOCATION FACTORS									
6	LAND & LAND RIGHTS		360	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
7	CUSTOMER RELATED		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
8	DEMAND RELATED		NCP4	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
9	ENERGY RELATED		NRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
10	OTHER			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
11	STRUCTURES AND IMPROVEMENTS		361	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
12	CUSTOMER RELATED		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	DEMAND RELATED		NCP4	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
14	ENERGY RELATED		NRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
15	OTHER			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16	STATION EQUIPMENT		362	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
17	CUSTOMER RELATED		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18	DEMAND RELATED		NCP4	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
19	ENERGY RELATED		NRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20	OTHER			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
21	POLES, TOWERS AND FIXTURES		364	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
22	PRIMARY CUSTOMER		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
23	PRIMARY DEMAND		NCP4	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
24	SECONDARY CUSTOMER		NRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
25	SECONDARY DEMAND		NCP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	OVERHEAD CONDUCTORS		365	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
27	PRIMARY CUSTOMER		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
28	PRIMARY DEMAND		NCP4	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
29	SECONDARY CUSTOMER		NRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	SECONDARY DEMAND		NCP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

	A	B	C	D	E	F	G	H	I	J
1			GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.						Schedule G-16	
2			PLANT IN SERVICE ALLOCATION FACTORS							
3			TEST YEAR ENDED SEPTEMBER 30, 2006							
4	CATEGORY	FERC ACCT #	FACTOR CODE	TOTAL	RESIDENTIAL	IRRIGATION	SMALL COMMERCIAL	LARGE COMMERCIAL	SECURITY LIGHTING	STREET LIGHTS
5	**UNDERGROUND CONDUIT**		366	100.00%	58.84%	0.00%	23.99%	17.17%	0.00%	0.00%
6	PRIMARY CUSTOMER		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
7	PRIMARY DEMAND		NCP2	100.00%	58.84%	0.00%	23.99%	17.17%	0.00%	0.00%
8	SECONDARY CUSTOMER		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	SECONDARY DEMAND			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
10	**UNDERGROUND CONDUCTORS**		367	100.00%	58.84%	0.00%	23.99%	17.17%	0.00%	0.00%
11	PRIMARY CUSTOMER		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
12	PRIMARY DEMAND		NCP2	100.00%	58.84%	0.00%	23.99%	17.17%	0.00%	0.00%
13	SECONDARY CUSTOMER		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
14	SECONDARY DEMAND		NCP2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
15	**LINE TRANSF/REGUL & CAPACITOR**		368	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
16	OVERHEAD CUSTOMER		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17	OVERHEAD DEMAND		NCP	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
18	UNDERGROUND CUSTOMER		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19	UNDERGROUND DEMAND		NCP2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20	**SERVICES**		369	100.00%	74.44%	7.36%	7.95%	0.14%	10.09%	0.03%
21	OVERHEAD CUSTOMER		CUST1	100.00%	74.44%	7.36%	7.95%	0.14%	10.09%	0.03%
22	OVERHEAD DEMAND		NCP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
23	UNDERGROUND CUSTOMER		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	UNDERGROUND DEMAND		NCP2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
25	**METERS**		370	100.00%	73.34%	14.50%	11.74%	0.41%	0.00%	0.00%
26	CUSTOMER RELATED		CUST3	100.00%	73.34%	14.50%	11.74%	0.41%	0.00%	0.00%
27	DEMAND RELATED		NCP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
28	ENERGY RELATED		NRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	OTHER			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	**INSTALL ON CUST PREM - SEC LIGHTS**		371	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
31	CUSTOMER RELATED		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
32	DEMAND RELATED		NCP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	ENERGY RELATED		NRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	ASSIGNED			100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
35	**EASEMENTS**		374	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
36	CUSTOMER RELATED		CUST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	DEMAND RELATED		NCP	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
38	ENERGY RELATED		NRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39	OTHER			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

	A	B	C	D	E	F	G	H	I	J
1	GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.								Schedule G-17	
2	SUMMARY OF RATE BASE ALLOCATION FACTORS									
3	TEST YEAR ENDED SEPTEMBER 30, 2006									
4	**CATEGORY**	**FERC ACCT #**	**FACTOR CODE**	**TOTAL**	**RESIDENTIAL**	**IRRIGATION**	**SMALL COMMERCIAL**	**LARGE COMMERCIAL**	**SECURITY LIGHTING**	**STREET LIGHTS**
5	TRANSMISSION RATE BASE ALLOCATION		TRRB	100.00%	47.86%	15.64%	19.92%	16.17%	0.33%	0.08%
6	**DISTRIBUTION RATE BASE FACTORS**									
7	LAND & LAND RIGHTS DISTRIBUTION	1360.00	360D	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
8	STATION EQUIPMENT-DISTRIBUTION	1362.00	362D	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
9	POLES, TOWERS & FIXTURES-DISTRIBUTION	1364.00	364D	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
10	OVERHEAD CONDUCTORS & DEVICES-DIST	1365.00	365D	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
11	UNDERGROUND CONDUIT-DISTRIBUTION	1366.00	366D	100.00%	58.84%	0.00%	23.99%	17.17%	0.00%	0.00%
12	UNDERGROUND CONDUCTORS & DEVICES-DIST	1367.00	367D	100.00%	58.84%	0.00%	23.99%	17.17%	0.00%	0.00%
13	LINE TRANSFORMERS	1368.00	368D	100.00%	48.38%	17.50%	19.73%	14.12%	0.23%	0.04%
14	SERVICES	1369.00	369D	100.00%	74.44%	7.36%	7.95%	0.14%	10.09%	0.03%
15	METERS	1370.00	370D	100.00%	73.34%	14.50%	11.74%	0.41%	0.00%	0.00%
16	INSTALLATIONS ON CONSUMERS' PREMISES	1371.00	371D	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%

	A	B	C	D	E	F	G	H	I	J
1	GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.								Schedule G-18	
2	DERIVED ALLOCATION FACTORS									
3	TEST YEAR ENDED SEPTEMBER 30, 2006									
4	CATEGORY	FERC ACCT #	FACTOR CODE	TOTAL	RESIDENTIAL	IRRIGATION	SMALL COMMERCIAL	LARGE COMMERCIAL	SECURITY LIGHTING	STREET LIGHTS
5	SUBTOTAL DERIVED FACTORS									
6	DISTRIBUTION PLANT ALLOCATION		DRB	100.00%	50.81%	15.91%	18.86%	12.89%	1.49%	0.04%
7	TRANS/DIST ALLOCATION		TDRB	100.00%	50.52%	15.88%	18.97%	13.22%	1.38%	0.04%
8	P T D PLANT ALLOCATION		PTDRB	100.00%	50.52%	15.88%	18.97%	13.22%	1.38%	0.04%
9	GENERAL PLANT SUBTOTAL FACTOR		SUBGRB	100.00%	50.52%	15.88%	18.97%	13.22%	1.38%	0.04%
10	TOTAL ELECTRIC PLANT ALLOCATION		PTDGRB	100.00%	50.52%	15.88%	18.97%	13.22%	1.38%	0.04%
11	PRODUCTION EXPENSE SUBTOT FACTOR		SUBP	100.00%	47.33%	13.64%	20.11%	18.38%	0.45%	0.09%
12	PRODUCTION EXPENSE FACTOR		PX	100.00%	47.33%	13.64%	20.11%	18.38%	0.45%	0.09%
13	TRANSMISSION EXPENSE SUBTOT FACTOR		SUBT	100.00%	47.86%	15.64%	19.92%	16.17%	0.33%	0.08%
14	TRANSMISSION EXPENSE FACTOR		TX	100.00%	47.86%	15.64%	19.92%	16.17%	0.33%	0.08%
15	DISTRIBUTION OPERATION SUBT FACTOR		SUBO	100.00%	58.69%	15.42%	16.83%	8.91%	0.13%	0.02%
16	DISTRIBUTION EXPENSE SUBTOT FACTOR		SUBD	100.00%	49.02%	16.77%	19.83%	14.13%	0.22%	0.04%
17	DISTRIBUTION EXPENSE FACTOR		DX	100.00%	51.77%	16.32%	18.94%	12.64%	0.30%	0.03%
18	BILLING/METER EXP. SUBTOT FACTOR		SUBB	100.00%	74.44%	7.36%	7.95%	0.14%	10.09%	0.03%
19	CUST ACCTS EXPENSE FACTOR		CAX	100.00%	74.44%	7.36%	7.95%	0.14%	10.09%	0.03%
20	CUSTOMER SVC EXPENSE FACTOR		CSIX	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
21	SALES ASSISTANCE EXPENSE FACTOR		SAX	100.00%	74.12%	9.43%	9.04%	0.22%	7.17%	0.02%
22	PTD ALLOC FACTOR		PTDX	100.00%	47.85%	13.71%	19.95%	17.95%	0.45%	0.09%
23	PTDS EXPENSE ALLOCATION		PTDSX	100.00%	48.70%	13.57%	19.60%	17.37%	0.67%	0.08%
24	O&M - PURCH POWER ALLOCATION		OM-PPF	100.00%	64.94%	12.76%	13.54%	5.45%	3.28%	0.03%
25	SALARY AND WAGE FACTOR		S&W	100.00%	55.69%	14.11%	16.60%	10.30%	3.26%	0.04%
26	P T D S&W FACTOR		S&WPTD	100.00%	50.72%	15.90%	18.90%	12.99%	1.46%	0.04%
27	A&G EXPENSE INCLUDING RESOURCES		AGWITH	100.00%	64.94%	12.76%	13.54%	5.45%	3.28%	0.03%
28	A&G EXPENSE ALLOCATION		SUBAGX	100.00%	55.63%	14.13%	16.63%	10.33%	3.24%	0.04%
29	TOTAL O&M EXPENSE ALLOCATION		O&MX	100.00%	49.18%	13.92%	19.43%	16.60%	0.79%	0.08%
30	PTD DEPRECIATION ALLOCATION		PTDDX	100.00%	50.54%	15.88%	18.96%	13.19%	1.38%	0.04%
31	PTD ACCUMULATED DEPR. ALLOCATION		PTDAD	100.00%	50.56%	15.88%	18.95%	13.17%	1.39%	0.04%
32	SUBTOTAL SALES		SUBSALES	100.00%	48.84%	12.30%	20.63%	17.29%	0.85%	0.09%
33	OPERATING REVENUE SUBTOTAL ALLOC		SUBREV	100.00%	48.83%	12.33%	20.63%	17.28%	0.84%	0.09%
34	REVENUE ALLOCATION FACTOR		REV	100.00%	48.83%	12.33%	20.63%	17.28%	0.84%	0.09%