ORIGINAL

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BEFORE THE ARIZONA CORPORATION

COMMISSIONERS
BOB STUMP- Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

IN THE MATTER OF THE APPLICATION OF OF GRAHAM COUNTY UTILITIES, INC. GAS DIVISION FOR APPROVAL OF A RATE INCREASE.	DOCKET NO. G-02527A-12-0321 **STAFF'S NOTICE OF FILING DIRECT RATE DESIGN TESTIMONY**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Direct Rate Design Testimony of Robert G. Gray and Prem K. Bahl in the above docket.

RESPECTFULLY SUBMITTED this 21st day of February 2013.

Maureen A. Scott, Senior Staff Counsel
Brian E. Smith, Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

Original and thirteen (13) copies of the foregoing filed this 21st day of February 2013 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copy of the foregoing mailed this
21st day of February 2013 to:

John V. Wallace
Grand Canyon State Electric
Cooperative Association
2210 South Priest Drive
Tempe, Arizona 85282

Kirk Gray
Graham County Electric Cooperative, Inc.
Post Office Drawer B
Pima, Arizona 85543

Kaye Christine

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY UTILITIES, INC. (GAS DIVISION) FOR APPROVAL OF A RATE INCREASE	DOCKET NO. G-02527A-12-0321

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 21, 2013

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SCHEDULES

EXECUTIVE SUMMARY
GRAHAM COUNTY UTILITIES, INC.
DOCKET NO. G-02527A-12-0321

My testimony in this proceeding addresses the issue of rate design for Graham County Utilities Inc. ("Graham"). My testimony also addresses the issue of a gas procurement review.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Robert G. Gray. I am an Executive Consultant III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant III.

A. In my capacity as an Executive Consultant III, I conduct analysis and provide recommendations to the Commission on a variety of electricity, natural gas, and water/wastewater matters. A copy of my resume is attached as Exhibit RGG-1.

Q. What is the scope of this testimony?

A. This testimony will address rate design for Graham County Utilities, Inc. ("Graham") as well the issue of a gas procurement review.

Q. Have you reviewed the testimony of Graham Witness John Wallace in regard to the rate design?

A. Yes. I have reviewed his testimony and will discuss his proposed changes to Graham's rate design as part of my testimony.

RATE DESIGN

Q. Please discuss Graham's current rate structures.

A. Graham currently has three customer classes including residential, commercial, and irrigation. Graham's residential customers currently pay a monthly customer charge of $13.00, a margin rate of $0.345 per therm, as well as the cost of gas component which is reflected through the monthly purchased gas adjustor ("PGA") rate. Irrigation customers currently pay a monthly customer charge of $21.00, a margin rate of $0.16 per therm, as well as the cost of gas component. Commercial customers currently pay a monthly customer charge of $24.00, a margin rate of $0.341 per therm, as well as the cost of gas component. The monthly PGA rate varies according to the changing natural gas commodity costs.

Q. Please describe what the rate design components are for a natural gas utility like Graham.

A. For a natural gas utility, costs fall into two general categories. The first category is the gas cost component, which captures the cost of the natural gas commodity as well as the cost of interstate pipeline transportation to deliver the natural gas from production areas in New Mexico and Texas to Graham's receipt points on the El Paso Natural Gas interstate pipeline system. An interest component is applied to any over or under-collected PGA bank balance. These costs are passed through the PGA mechanism. The second category captures all costs other than those passed through the PGA mechanism. These costs include things like labor, billing, and infrastructure costs. These costs are recovered through the monthly customer charge as well as the non-gas cost per therm tariff or margin rate. In a rate case, the Commission addresses the tariff cost components contained in the tariff rates. The Commission may choose to adjust how the PGA mechanism works in a general rate proceeding, but does not generally set the monthly PGA rate within a rate proceeding as it is set according to established mathematical calculations.

Q. Please discuss how Graham represents the cost of gas component in its rate filing.

A. Graham represents the cost of gas differently in its application. At times it reflects a PGA rate of $0.4888 per therm; yet at other times in its rate filing is reflects a PGA rate of $0.43705 per therm.

When comparing current and proposed rates, it is best to represent rates using a consistent cost of gas component number, as gas costs are passed through the PGA mechanism and changes in tariff rates in a general rate case do not impact the pass through of gas costs. Graham's use of different gas cost numbers makes it difficult to understand the changes in tariff rates being proposed by Graham, and their ultimate impact on customers. Throughout Staff's discussion of rate design and presentation of proposed rates, Staff uses a constant cost of gas of $0.43705 per therm.

Q. What rates are being proposed in this case by Graham?

A. Graham is proposing to increase the residential monthly customer charge from $13.00 to $16.25, the irrigation monthly customer charge from $21.00 to $26.25, and the commercial monthly customer charge from $24.00 to $30.00. Graham is not proposing any change in the per therm tariff rates for the various customers classes.

Q. Please comment on Graham's proposed rates.

A. Staff believes that Graham's proposed rates increase the customer charges too much and Staff would favor a more gradual and measured increase in customer charges, with some portion of the increase also reflected in Graham's per therm tariff rates.

Q. Please discuss Staff's proposed rates in this case.

A. Staff recommends that the residential monthly customer charge be set at $15.00 and the residential margin rate be set at $0.378 per therm. Staff recommends that the irrigation monthly customer charge be set at $24.00 and the irrigation margin rate be set at $0.18 per therm. Staff recommends that the commercial monthly customer charge be set at $28.00 and the commercial margin rate be set at $0.36 per therm. Staff's proposed rates take into consideration the cost of service analysis by Staff Witness Prem Bahl. Staff moderates the monthly customer charge increases proposed by Graham and increases the per therm tariffed rates for all three of Graham's rate classes. Graham has not proposed any changes to the rates and charges for other services and Staff's proposed change discussed below does not change the revenue Graham would receive.

Q. Will Staff's proposed rates provide sufficient revenues to Graham using Staff's revenue requirement.

A. Yes. Staff Witness Brian Bozzo proposes total operating revenue of $3,466,484 for Graham. Reducing this number by $1,399,908 for test year gas costs and $40,043 for other revenue (from miscellaneous charges such as establishment of service charges, late fees, and meter test fees), results in total revenue to be recovered from Graham's tariffed rates of $2,026,533. The revenue generated from Staff's proposed rates is $2,025,692. Staff's proposal reflects the same revenue from other services (such as establishment of service, meter reread charges, late fees, etc.) as Graham received during the test year, $40,043.

Q. Please describe how Staff deals with the cost of gas in representing overall rates to be paid by Graham's customers under Staff's proposed rates, as well as Staff's customer bill impact estimates.

A. As noted before, Graham's application and attached schedules reflect two different gas cost numbers in various places, $0.4888 per therm and $0.43705 per therm. Staff uses the $0.43705 per therm number, as under Staff's analysis it is closer to the actual cost of gas being paid by Graham's customers in recent months.

Q. Please discuss what the residential customer bill impacts would be under Staff's proposed rates.

A. For an annual mean residential customer bill reflecting consumption of 34 therms, the customer bill under Staff's proposal would be $42.71, an increase of 7.9 percent and $3.12 over the bill of $39.59 under Graham's existing rates. For a mean residential customer bill in Graham's winter peak month of January, reflecting consumption of 84 therms, the residential customer bill under Staff's proposal would be $83.46, an increase of 6.1 percent and $4.77 over the bill of $78.69 under Graham's existing rates.

Q. Please discuss what the irrigation customer bill impacts would be under Staff's proposed rates.

A. For an annual mean irrigation customer bill reflecting consumption of 201 therms, the customer bill under Staff's proposal would be $148.03, an increase of 5.0 percent and $7.02 over the bill of $141.01 under Graham's existing rates. For a mean irrigation customer bill in Graham's summer peak month of August, reflecting consumption of 329 therms, the customer bill under Staff's proposal would be $227.01, an increase of 4.4 percent and $9.58 over the bill of $217.43 under Graham's existing rates.

Q. Please discuss what the commercial customer bill impacts would be under Staff's proposed rates.

A. For an annual mean commercial customer bill reflecting consumption of 281 therms, the customer bill under Staff's proposal would be \$251.97, an increase of 3.8 percent and \$9.34 over the bill of \$242.63 under Graham's existing rates. For a mean commercial customer bill in Graham's winter peak month of January, reflecting consumption of 637 therms, the customer bill under Staff's proposal would be \$535.72, an increase of 3.1 percent and \$16.10 over the bill of \$519.62 under Graham's existing rates.

Q. Please discuss Staff's tiered rate alternative.

A. In several recent rate cases, including Southwest Gas (Decision No. 72723, January 6, 2012) and UNS Gas (Decision No. 73142, May 6, 2012), the Commission has ordered the utility company to file, in its next general rate proceeding, an inclining block/tiered rate proposal as one of its rate design proposals for Commission consideration. In recognition of these recent orders, Staff has prepared an alternative tiered rate design in this proceeding for Commission consideration. This alternative rate design is only for residential customers, with irrigation and commercial customers being unaffected by the alternative rate proposal. Staff is not recommending adoption of this alternative at this time, but offers it as a possible alternative in case the Commission wishes to consider a rate design similar to what is used for water and electric utilities. If the Commission does not adopt the alternative tiered rate design in this proceeding, Staff recommends that Graham be required to include, as part of its next general rate application, an inclining block rate structure as one of its rate design proposals.

Q. Please compare Staff's recommended rate design proposal in this proceeding to Staff's alternative tiered rate design.

A. The main impact of the tiered rate design is to reduce customer bills for low use customers and increase customer bills for high use customers in comparison to Staff's recommended rate design proposal. The creation of an inclining block rate structure could incent high use customers to use natural gas more efficiently.

RATES AND CHARGES FOR OTHER SERVICES

Q. Has Graham proposed any changes to its rates and charges for other services?

A. No.

Q. Is Staff recommending any changes to Graham's rates and charges for other services?

A. Yes. The Company currently has an establishment after-hours charge of $50.00. The Company also has a reconnection of service after-hours charge of $50.00. The Company has proposed no charges to these rates.

Staff agrees that an additional fee for service provided after normal business hours is appropriate when such service is at the customer's request. Such a tariff compensates the utility for additional expenses incurred from providing after-hours service. Moreover, Staff concludes that it is appropriate to apply an after-hours service charge in addition to the charge for any utility service provided after hours at the customer's request. Therefore, Staff recommends the removal of both the establishment of service – after hours charge and reconnection of service after-hours charge. For example, under Staff's proposal, a customer would be subject to a $30 establishment of service if it is done during normal business hours, but would pay an additional $20 after-hours fee if customer requested that the establishment of service be done after normal working hours. Staff believes that this charge will simplify Graham's rates and charges for other services and is consistent with how after hours work is treated for other utilities in recent cases before the Commission.

Q. Please summarize your recommended changes to Graham's rates and charges for other services.

A. Staff recommends elimination of the Establishment of Service – After Hours and Reconnection of Service – After Hours charges and the creation of a $20.00 after hours service charge that would apply to utility services provided to customers after hours.

GAS PROCUREMENT REVIEW

Q. Has Staff conducted a review of Graham's gas procurement activities recently?

A. Yes.

Q. Please describe Staff's recent review of Graham's gas procurement activities.

A. As part of Graham's previous rate proceeding (Docket No. G-02527A-09-0088) Staff reviewed Graham's procurement activities for gas supplies acquired between January 2006 and June 2009. In that case, Staff recommended that the Commission make a finding that Graham's procurement activities were prudent, a recommendation reflected in the Commission's final order in the case (Decision No. 71690, May 3, 2010).

Q. Have Graham's procurement activities changed significantly since the previous rate case?

A. No.

Q. Does Staff believe it is necessary to conduct a procurement review in this current rate proceeding.

A. No. Since Graham's last review was in 2009 and 2010 and there has been no change in Graham's procurement activities in recent years, Staff believes that it is not necessary to conduct a procurement review in this proceeding. However, Staff anticipates conducting a procurement review in the next future rate proceeding Graham files with the Commission.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. My testimony includes the following recommendations:

Rate Design

1. Staff recommends that the residential customer charge be set at $15.00 per month and the residential margin rate should be set at $0.378 per therm.

2. Staff further recommends that the irrigation customer charge be set at $24.00 per month and the irrigation margin rate should be set at $0.18 per therm.

3. Staff further recommends that the commercial customer charge be set at $28.00 per month and the commercial margin rate should be set at $0.36 per therm.

4. Staff further recommends that, if Staff's alternative tiered rate structure is not adopted in this proceeding, that Graham be required to include, as part of its next general rate application, an inclining block rate structure as one of its rate design proposals.

Rates and Charges for Other Services

5. Staff further recommends elimination of the Establishment of Service – After Hours and Reconnection of Service – After Hours charges and the creation of a $20.00 after hours service charge that would apply to utility services provided to customers after hours.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

RESUME

ROBERT G. GRAY

Education

B.A. Geography, University of Minnesota-Duluth (1988)
M.A. Geography, Arizona State University (1990) Thesis: *A Model for Optimizing the Federal Express Overnight Delivery Aircraft Network.*

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Executive Consultant III (November 2007 – present), Public Utility Analyst V (October 2001 – November 2007), Senior Economist (August 1997 – October 2001), Economist II (June 1991 - July 1997), Economist I (June 1990 - June 1991). Conduct economic and policy analyses on a variety of natural gas issues in Arizona, including gas procurement, rate design, interstate pipeline issues, revenue decoupling, energy conservation, low income issues, natural gas research and development funding, customer services issues, special contracts, various tariff matters, and other natural gas issues. Conduct economic and policy analyses on a variety of electricity issues in Arizona, power plant and transmission line siting cases, energy efficiency, renewable energy standards, rate design, time-of-use service, and low income issues. Prepare recommendations and present written and oral testimony before the Commission and organize workshops and other proceedings on various utility industry issues. Represent the ACC in natural gas proceedings at the Federal Energy Regulatory Commission, at the North American Energy Standards Board, and on the National Association of Regulatory Utility Commissioners' Staff Subcommittee on Gas, including serving as a past Vice-Chair and Chair of the NARUC Staff Subcommittee on Gas.

Testimony

Resource Planning for Electric Utilities, (Docket No. 0000-90-088), Arizona Corporation Commission, 1990.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-92-073), Arizona Corporation Commission, 1993.

Resource Planning for Electric Utilities, (Docket No. 0000-93-052), Arizona Corporation Commission, 1993.

Arizona Public Service Company, Rate Settlement (Docket No. E-1345-94-120), Arizona Corporation Commission, 1994.

U S West Communications, Rate Case (Docket No. E-1051-93-183), Arizona Corporation Commission, 1995.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-95-433), Arizona Corporation Commission, 1996.

Resource Planning for Electric Utilities (Docket No. U-000-95-506), Arizona Corporation Commission, 1996.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. U-1551-96-596), Arizona Corporation Commission, 1997.

Black Mountain Gas Company - Northern States Power Company, Merger (Docket Nos. G-03493A-98-0017, G-01970A-98-0017), Arizona Corporation Commission, 1998.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-98-0695, G-03493A-98-0705), Arizona Corporation Commission, 1999.

Graham County Utilities Company Rate Case (Docket No. G-02527A-00-0378), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Cave Creek Division Rate Case (Docket No. G-03703A-00-0283), Arizona Corporation Commission, 2000.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. G-01551A-00-0309), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-01-0263), Arizona Corporation Commission, 2001.

Duncan Rural Services – Natural Gas Rate Case (Docket No. G-02528A-01-0561), Arizona Corporation Commission, 2001.

Toltec Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Y-01-0112), September 2001.

Lap Paz Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000AA-01-0116), December 2001.

Bowie Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000BB-01-0118), December 2001.

Southwest Gas Corporation, Acquisition of Black Mountain Gas Company (Docket No. G-01551A-02-0425), Arizona Corporation Commission, 2002.

Wellton-Mohawk Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Z-01-0114), February 2003.

Arizona Public Service Company, Rate Proceeding (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004.

Graham County Utilities Company Rate Case (Docket No. G-02527A-04-0301), Arizona Corporation Commission, 2004.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-04-0876), Arizona Corporation Commission, 2004.

Southern California Edison, Devers – Palo Verde 2 Transmission Line Application before the Arizona Power Plant and Line Siting Committee, (L-00000A-06-0295-00130), 2006.

Semstream Arizona Propane Acquisition of Energy West (Docket G-02696A-06-0515), Arizona Corporation Commission, 2006.

UNS Gas Inc., Rate Proceeding (Docket No. G-04204A-06-0463), Arizona Corporation Commission, 2007.

Semstream Arizona Propane Acquisition of Black Mountain Gas Company – Page Division (Docket G-03703A-06-0694), Arizona Corporation Commission, 2007.

Northern Arizona Energy, LLC, Northern Arizona Energy Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000FF-07-0134-00133), 2007.

Arizona Public Service, Palo Verde Hub to North Gila 500 kV Transmission Lint Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000D-07-0566-00135), 2007.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-07-0504), Arizona Corporation Commission, 2008.

Arizona Solar One, LLC, Solana Generating Station and Gen-Tie Application before the Arizona Power Plant and Line Siting Committee, (L-00000GG-08-0407-00139 and L-00000GG-08-0408-00140), 2008.

Coolidge Power Corporation, Coolidge Power Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000HH-08-0422-00141), 2008.

UNS Gas Inc., Rate Proceeding (Docket No. G-04204A-08-0571), Arizona Corporation Commission, 2009.

El Paso Natural Gas Company, Rate Proceeding (Docket No. RP08-426), Federal Energy Regulatory Commission, 2009.

Arizona Water/Global Water CC&N Extension/Acquisition Proceeding (Docket Nos. W-01445A-06-0199, etc.), Arizona Corporation Commission, 2009.

Graham County Utilities Company Rate Proceeding (Docket No. G-02527A-09-0088), Arizona Corporation Commission, 2009.

Southwest Gas Corporation Rate Proceeding (Docket No. G-01551A-10-0458), Arizona Corporation Commission, 2010.

UNS Gas Inc., Rate Proceeding (Docket No. G-04204A-11-0158), Arizona Corporation Commission, 2011.

Semstream Arizona Propane, LLC Rate Proceeding, (Docket No. G-20471A-11-0150), Arizona Corporation Commission, 2011.

El Paso Natural Gas Company, Rate Proceeding, (Docket No. RP10-1398), Federal Energy Regulatory Commission, 2011.

Publications

(with David Berry, Kim Clark, Lewis Gale, Barbara Keene, and Harry Sauthoff) Staff Report on Resource Planning. (Docket No. U-0000-90-088) Arizona Corporation Commission, 1990.

(with Prem Bahl) "Transmission Access Issues: Present and Future," October, 1991.

(with David Berry) Substitution of Photovoltaics for Line Extensions: Creating Consumer Choices. Arizona Corporation Commission, 1992.

(with Barbara Keene and Kim Clark) Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees, December, 1992.

(with Mike Kuby) "The Hub and Network Design Problem With Stopovers and Feeders: The Case of Federal Express," Transportation Research A., Vol. 27A, 1993, pp. 1-12.

(with David Berry) Staff Guidelines on Photovoltaics Versus Line Extensions. Arizona Corporation Commission, January 28, 1993.

(with Ray Williamson, Robert Hammond, Frank Mancini, and James Arwood) The Solar Electric Option (Instead of Power Line Extension). A joint publication of the Arizona Corporation Commission and the Arizona Department of Commerce Energy Office, August, 1993.

(with David Berry, Kim Clark, Barbara Keene, Jesse Tsao, Ray Williamson, Randall Sable, Roni Washington, Wilfred Shand, and Prem Bahl) Staff Report on Resource Planning. (Docket No. U-0000-93-052) Arizona Corporation Commission, 1993.

Staff Report On Rural Local Calling Areas. (Docket No. E-1051-93-183) Arizona Corporation Commission, March, 1994.

(with David Berry, Kim Clark, Barbara Keene, Glenn Shippee, Julia Tsao, and Ray Williamson) Staff Report on Resource Planning. (Docket No. U-000-95-506) Arizona Corporation Commission, 1996.

(with Barbara Keene) "Customer Selection Issues," NRRI Quarterly Bulletin, Vol. 19, No. 1, Spring 1998, National Regulatory Research Institute.

Staff Report on Purchased Gas Adjustor Mechanisms, (Docket No. G-00000C-98-0568) Arizona Corporation Commission, October 19, 1998.

Staff Report on the Rolling Average PGA Mechanism, (Docket No. G-00000C-98-0568),Arizona Corporation Commission, September 6, 2000.

Staff Report on the Use of a Circuit-Breaker in Adjustor Mechanisms, Arizona Corporation Commission, September 3, 2003.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. G-01551A-04-0192), Arizona Corporation Commission, June 2, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. E-01345A-04-0273), Arizona Corporation Commission, August 16, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project , (Docket No. E-01345A-05-0895), Arizona Corporation Commission, March 2, 2006.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-01551A-06-0107), Arizona Corporation Commission, May 16, 2006.

Staff Report on UNS Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-04204A-06-0627), Arizona Corporation Commission, January 30, 2007.

Staff Review of UNS Electric 2008 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-07-0593), Arizona Corporation Commission, March 25, 2008.

Staff Report on Semstream Arizona Propane, Payson Division Bankruptcy, Reorganization, and other issues, Arizona Corporation Commission, June 6, 2008.

Staff Review of UNS Electric 2009 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-07-0593), Arizona Corporation Commission, November 26, 2008.

Staff Review of Tucson Electric Power 2009 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-07-0594), Arizona Corporation Commission, November 26, 2008.

Staff Report for Arizona Water Company and Global Water Resources LLC's Consolidated Docket Addressing Numerous Requests for Extensions of Certificates of Convenience and Necessity for Water and Wastewater Service as Well as the Transfer of Assets, (Docket No. W01445A-06-0199, etc.), Arizona Corporation Commission, May 10, 2009.

Staff Review of UNS Electric 2010 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-09-0347), Arizona Corporation Commission, January 5, 2010.

Staff Review of Tucson Electric Power 2010 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-09-0340), Arizona Corporation Commission, January 5, 2010.

Staff Review of UNS Electric 2011 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-10-0265), Arizona Corporation Commission, November 8, 2010.

Staff Review of Tucson Electric Power 2011 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-10-0266), Arizona Corporation Commission, November 9, 2010.

Staff Review of UNS Electric 2012 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-11-0267), Arizona Corporation Commission, October 25, 2011.

Staff Review of Tucson Electric Power 2012 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-11-0269), Arizona Corporation Commission, October 25, 2011.

Staff Review of UNS Electric 2013 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-12-0297), Arizona Corporation Commission, October 18, 2012.

Staff Review of Tucson Electric Power 2013 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-12-0296), Arizona Corporation Commission, October 18, 2012.

Additional Training

1990	Seminars on Regulatory Economics
1993	PURTI course on Public Utilities and the Environment
1996	Center for Public Utilities Workshop on Gas Unbundling and Retail Competition
1997	NARUC 6th Annual Natural Gas Conference
1998	Local Distribution Company Restructuring and Retail Access and Competition Conference
1998	NARUC 7th Annual Natural Gas Conference
1999 – 2007, 2010, 2012	NARUC Summer Committee Meetings
2001	Center for Public Utilities Workshop on Risk Management in Gas Purchasing
2003-2008	NARUC Winter Committee Meetings
2004-2007	NARUC Annual Convention

Memberships

NARUC – Staff Subcommittee on Gas – member, 1998 - present
NARUC – Staff Subcommittee on Gas – Vice-Chair - 2002 - 2004
NARUC – Staff Subcommittee on Gas – Chair - 2005 - 2007
Michigan State Institute for Public Utilities – NARUC Advisory Committee – 2005-2007
NARUC – North American Energy Standards Board Advisory Council – 2006 - present
NARUC – DOE LNG Partnership – 2003 - present

Rate Design

	Residental	Irrigation	Commercial
Existing Rates			
Customer Charge	$13.00	$21.00	$24.00
Tariffed Rate	$0.34500	$0.16000	$0.34100
Monthly PGA Rate	$0.43705	$0.43705	$0.43705
Graham Proposed Rates			
Customer Charge	$16.25	$26.25	$30.00
Tariffed Rate	$0.34500	$0.16000	$0.34100
Monthly PGA Rate	$0.43705	$0.43705	$0.43705
Staff Proposed Rates			
Customer Charge	$15.00	$24.00	$28.00
Tariffed Rate	$0.37800	$0.18000	$0.36000
Monthly PGA Rate	$0.43705	$0.43705	$0.43705
Staff Tiered Rate Alternative			
Customer Charge	$15.00	$24.00	$28.00
Tariffed Rate - 50 therms or less	$0.34000	$0.18000	$0.36000
Tariffed Rate - Over 50 therms	$0.40000	$0.18000	$0.36000
Monthly PGA Rate	$0.43705	$0.43705	$0.43705

Staff Revenue Requirement Target	$2,026,533
Revenue Under Staff Rate Proposal	$2,025,692
Revenue Under Staff Tiered Rate Alternative	$2,022,148

Revenue from Rate and Charges for Other Services	
Test Year	$40,043
Graham Proposal	$40,043
Staff Proposal	$40,043
Staff Tiered Rate Alternative	$40,043

	Rate Schedule Revenue	Gas Cost (Monthly PGA Rate)	Tariffed Rate (non gas cost) Revenue	Revenue From Misc. Charges	Total Revenue
Existing Rates	$3,069,845	$1,254,993	$1,814,852	$40,043	$3,109,888
Company Proposed Rates	$3,277,614	$1,254,993	$2,022,620	$40,043	$3,317,657
Staff Proposed Rates	$3,280,686	$1,254,993	$2,025,692	$40,043	$3,320,729
Staff Tiered Rate Alternative	$3,277,141	$1,254,993	$2,022,148	$40,043	$3,317,184

Assumes Constant PGA Rate of $0.043705 per therm

Existing Rates

Residential	Number	Rate	Total	
Customer Bills	56,180	$13.00	$730,340	
Partial Bills	1,732	$13.00	$22,520	
Tariffed Rate	1,960,668	$0.34500	$676,430	
Monthly PGA Rate	1,960,668	$0.43705	$856,910	
Total				$2,286,200
Irrigation				
Customer Bills	77	$21.00	$1,617	
Partial Bills	13	$21.00	$273	
Tariffed Rate	18,064	$0.16000	$2,890	
Monthly PGA Rate	18,064	$0.43705	$7,895	
Total				$12,675
Commercial				
Customer Bills	3,142	$24.00	$75,408	
Partial Bills	39	$24.00	$936	
Tariffed Rate	892,778	$0.34100	$304,437	
Monthly PGA Rate	892,778	$0.43705	$390,189	
Total				$770,970
Total - All Classes				$3,069,845
Total Non-gas cost revenue				$1,814,852

Company Proposed Rates

Residential	Number	Rate	Total	
Customer Bills	56,180	$16.25	$912,925	
Partial Bills	1,732	$16.25	$28,145	
Tariffed Rate	1,960,668	$0.34500	$676,430	
Monthly PGA Rate	1,960,668	$0.43705	$856,910	
Total				$2,474,410
Irrigation				
Customer Bills	77	$26.25	$2,021	
Partial Bills	13	$26.25	$341	
Tariffed Rate	18,064	$0.16000	$2,890	
Monthly PGA Rate	18,064	$0.43705	$7,895	
Total				$13,148
Commercial				
Customer Bills	3,142	$30.00	$94,260	
Partial Bills	39	$30.00	$1,170	
Tariffed Rate	892,778	$0.34100	$304,437	
Monthly PGA Rate	892,778	$0.43705	$390,189	
Total				$790,056
Total - All Classes				$3,277,614
Total Non-gas cost revenue				$2,022,620

Note: Graham's revenue from the tariffed rates, based on the billing data provided by Graham in the rate proceeding, $2,022,620, is slightly lower, by $3,913, than the revenue requested by Graham and recommended by Staff Witness Bozzo of $2,026,533. This differential is diminimus.

Staff Proposed Rates

Residential	Number	Rate	Total	
Customer Bills	56,180	$15.00	$842,700	
Partial Bills	1,732	$15.00	$25,980	
Tariffed Rate	1,960,668	$0.37800	$741,133	
Monthly PGA Rate	1,960,668	$0.43705	$856,910	
Total				$2,466,722
Irrigation				
Customer Bills	77	$24.00	$1,848	
Partial Bills	13	$24.00	$312	
Tariffed Rate	18,064	$0.18000	$3,252	
Monthly PGA Rate	18,064	$0.43705	$7,895	
Total				$13,306
Commercial				
Customer Bills	3,142	$28.00	$87,976	
Partial Bills	39	$28.00	$1,092	
Tariffed Rate	892,778	$0.36000	$321,400	
Monthly PGA Rate	892,778	$0.43705	$390,189	
Total				$800,657
Total - All Classes				$3,280,686
Total Non-gas cost revenue				$2,025,692

Staff Tiered Rate Alternative

Residential	Number	Rate	Total	
Customer Bills	56,180	$15.00	$842,700	
Partial Bills	1,732	$15.00	$25,980	
Tariffed Rate-50 therms or under	777,986	$0.34000	$264,515	
Tariffed Rate-over 50 therms	1,182,682	$0.40000	$473,073	
Monthly PGA Rate	1,960,668	$0.43705	$856,910	
Total				$2,463,178
Irrigation				
Customer Bills	77	$24.00	$1,848	
Partial Bills	13	$24.00	$312	
Tariffed Rate	18,064	$0.18000	$3,252	
Monthly PGA Rate	18,064	$0.43705	$7,895	
Total				$13,306
Commercial				
Customer Bills	3,142	$28.00	$87,976	
Partial Bills	39	$28.00	$1,092	
Tariffed Rate	892,778	$0.36000	$321,400	
Monthly PGA Rate	892,778	$0.43705	$390,189	
Total				$800,657
Total - All Classes				$3,277,141
Total Non-gas cost revenue				$2,022,148

Exhibit RGG-3

Customer Bill Estimates

Residential Therms		Current Rates	Company Proposed Rates	Staff Proposed Rates	Staff Tiered Rate Alternative	Increase Company Proposed Rates	Increase Staff Proposed Rates	Increase Staff Tiered Rate Alternative	Percent Increase Company Proposed Rates	Percent Increase Staff Proposed Rates	Percent Increase Staff Tiered Rate Alternative
5		$16.91	$20.16	$19.08	$18.89	$3.25	$2.17	$1.98	19.2%	12.8%	11.7%
10		$20.82	$24.07	$23.15	$22.77	$3.25	$2.33	$1.95	15.6%	11.2%	9.4%
15		$24.73	$27.98	$27.23	$26.66	$3.25	$2.50	$1.93	13.1%	10.1%	7.8%
20		$28.64	$31.89	$31.30	$30.54	$3.25	$2.66	$1.90	11.3%	9.3%	6.6%
25		$32.55	$35.80	$35.38	$34.43	$3.25	$2.83	$1.88	10.0%	8.7%	5.8%
30		$36.46	$39.71	$39.45	$38.31	$3.25	$2.99	$1.85	8.9%	8.2%	5.1%
34	annual mean	$39.59	$42.84	$42.71	$41.42	$3.25	$3.12	$1.83	8.2%	7.9%	4.6%
40		$44.28	$47.53	$47.60	$46.08	$3.25	$3.32	$1.80	7.3%	7.5%	4.1%
50		$52.10	$55.35	$55.75	$53.85	$3.25	$3.65	$1.75	6.2%	7.0%	3.4%
75		$71.65	$74.90	$76.13	$74.78	$3.25	$4.47	$3.13	4.5%	6.2%	4.4%
84	January mean	$78.69	$81.94	$83.46	$82.31	$3.25	$4.77	$3.62	4.1%	6.1%	4.6%
100		$91.21	$94.46	$96.51	$95.71	$3.25	$5.30	$4.50	3.6%	5.8%	4.9%
150		$130.31	$133.56	$137.26	$137.56	$3.25	$6.95	$7.25	2.5%	5.3%	5.6%
200		$169.41	$172.66	$178.01	$179.41	$3.25	$8.60	$10.00	1.9%	5.1%	5.9%
300		$247.62	$250.87	$259.52	$263.12	$3.25	$11.90	$15.50	1.3%	4.8%	6.3%
500		$404.03	$407.28	$422.53	$430.53	$3.25	$18.50	$26.50	0.8%	4.6%	6.6%
1000		$795.05	$798.30	$830.05	$849.05	$3.25	$35.00	$54.00	0.4%	4.4%	6.8%
Irrigation											
10		$26.97	$32.22	$30.17	$30.17	$5.25	$3.20	$3.20	19.5%	11.9%	11.9%
25		$35.93	$41.18	$39.43	$39.43	$5.25	$3.50	$3.50	14.6%	9.7%	9.7%
50		$50.85	$56.10	$54.85	$54.85	$5.25	$4.00	$4.00	10.3%	7.9%	7.9%
75		$65.78	$71.03	$70.28	$70.28	$5.25	$4.50	$4.50	8.0%	6.8%	6.8%
100		$80.71	$85.96	$85.71	$85.71	$5.25	$5.00	$5.00	6.5%	6.2%	6.2%
200		$140.41	$145.66	$147.41	$147.41	$5.25	$7.00	$7.00	3.7%	5.0%	5.0%
201	annual mean	$141.01	$146.26	$148.03	$148.03	$5.25	$7.02	$7.02	3.7%	5.0%	5.0%
300		$200.12	$205.37	$209.12	$209.12	$5.25	$9.00	$9.00	2.6%	4.5%	4.5%
329	August mean	$217.43	$222.68	$227.01	$227.01	$5.25	$9.58	$9.58	2.4%	4.4%	4.4%
400		$259.82	$265.07	$270.82	$270.82	$5.25	$11.00	$11.00	2.0%	4.2%	4.2%
500		$319.53	$324.78	$332.53	$332.53	$5.25	$13.00	$13.00	1.6%	4.1%	4.1%
750		$468.79	$474.04	$486.79	$486.79	$5.25	$18.00	$18.00	1.1%	3.8%	3.8%
Commercial											
10		$31.78	$37.78	$35.97	$35.97	$6.00	$4.19	$4.19	18.9%	13.2%	13.2%
20		$39.56	$45.56	$43.94	$43.94	$6.00	$4.38	$4.38	15.2%	11.1%	11.1%
50		$62.90	$68.90	$67.85	$67.85	$6.00	$4.95	$4.95	9.5%	7.9%	7.9%
100		$101.81	$107.81	$107.71	$107.71	$6.00	$5.90	$5.90	5.9%	5.8%	5.8%
150		$140.71	$146.71	$147.56	$147.56	$6.00	$6.85	$6.85	4.3%	4.9%	4.9%
200		$179.61	$185.61	$187.41	$187.41	$6.00	$7.80	$7.80	3.3%	4.3%	4.3%
281	annual mean	$242.63	$248.63	$251.97	$251.97	$6.00	$9.34	$9.34	2.5%	3.8%	3.8%
400		$335.22	$341.22	$346.82	$346.82	$6.00	$11.60	$11.60	1.8%	3.5%	3.5%
500		$413.03	$419.03	$426.53	$426.53	$6.00	$13.50	$13.50	1.5%	3.3%	3.3%
637	January mean	$519.62	$525.62	$535.72	$535.72	$6.00	$16.10	$16.10	1.2%	3.1%	3.1%
750		$607.54	$613.54	$625.79	$625.79	$6.00	$18.25	$18.25	1.0%	3.0%	3.0%
1000		$802.05	$808.05	$825.05	$825.05	$6.00	$23.00	$23.00	0.7%	2.9%	2.9%
1500		$1,191.08	$1,197.08	$1,223.58	$1,223.58	$6.00	$32.50	$32.50	0.5%	2.7%	2.7%
2000		$1,580.10	$1,586.10	$1,622.10	$1,622.10	$6.00	$42.00	$42.00	0.4%	2.7%	2.7%
3000		$2,358.15	$2,364.15	$2,419.15	$2,419.15	$6.00	$61.00	$61.00	0.3%	2.6%	2.6%

Assumes constant cost of gas of $0.43075 per therm

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY UTILITIES, INC. (GAS DIVISION) FOR APPROVAL OF A RATE INCREASE	DOCKET NO. G-02527A-12-0321

DIRECT

TESTIMONY

OF

PREM K. BAHL

ELECTRIC UTILITIES ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 21, 2013

TABLE OF CONTENTS

EHXIBIT 1

(COST OF SERVICE SCHEDULES G-1 THRU G-8)

EXECUTIVE SUMMARY
GRAHAM COUNTY UTILITIES INC., GAS DIVISION
DOCKET NO. G-02527A-12-0321

Prem Bahl's testimony discusses Utilities Division Staff's ("Staff") review of Graham County Utilities Inc., Gas Division's ("Graham") Cost of Service Study ("COSS") for the rate case filed with the Arizona Corporation Commission ("Commission"), and presents the results of Staff's analysis.

Based on its review of Graham's COSS, Staff's conclusions and recommendations are as follows:

1. It is Staff's conclusion that Graham performed the COSS consistent with the methodology generally accepted in the industry, and developed most of the allocation factors appropriately. Certain allocation factors were modified by Staff, as discussed in Staff's testimony.

2. Staff further concludes that, based on the evaluation of the COSS model utilized by Graham and the changes Staff made in the allocation factors, the results of the COSS are satisfactory.

3. Staff recommends that Graham make the following changes in the COSS allocation factors.

   - F3 ~ Distribution Mains should be allocated 100 percent to Demand. On G-6, F3 should be changed from 50 percent Demand and 50 percent Weighted Customers (weighted according to installation and meter reading costs) to 100 percent Demand.

   - F3a ~ for Mains & Services should be changed from 50 percent Demand and 50 percent Weighted Customers to 70.84 percent Demand and 29.16 percent Weighted Customers, based on actual plant in service.

   - F6 ~ On Schedule G-7, F6 was mis-labeled, representing Meter Reading Expenses, and Meter Reading & installation. It should be designated as F6a, and should be changed to 53.40 percent Weighted Customers and 46.60 percent Customers.

   - F6a ~ On Schedule G-8, F6a should be changed from 100 percent Customers to 53.40 percent Weighted Customers and 46.60 percent Customers.

   - F7 allocating Depreciation on Mains to 50 percent Demand and 50 percent Weighted Customers should be changed to 47.26 percent Demand and 52.74 percent Weighted Customers.

- D-1 ~ On Schedule G-8, for Winter Peak Demand, replace 0.00 percent by 100 percent under the column entitled "Total."

4. Staff further recommends that Graham continue to utilize the current COSS model, including the revised allocation factors for allocating expenditures, including the ones associated with Distribution Mains and Distribution Mains and Services in all future rate cases.

5. Staff further recommends that Graham's COSS cost allocations and factors be accepted with Staff's above noted allocation factor revisions, which are reflected in Staff's COSS G-Schedules under attached Exhibit 1.

I. INTRODUCTION

Q. Please state your name, occupation, 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 Master's 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 the Agra University, India, in 1957.

Q. Please describe your pertinent work experience.

I worked at the Arizona Corporation Commission from 1988 to 1998 as a Utilities Consultant, and have subsequently been re-employed at the Commission as an Electric Utilities Engineer since June 2002 until the present time. Since rejoining the Commission, I have reviewed utilities' load curtailment plans; coordinated with the Commission Consultants to hold ten workshops to report on the second through the sixth Biennial Transmission Assessments ("BTA") for Arizona. I have also worked on compliance of Certificates of Environmental Compatibility including Harquahala, Panda Gila River, Red Hawk, Northern Arizona Project, and Coolidge power plants. In 2004, I testified in the line siting cases of TEP's 138 kV Robert Bills-Wilmont Substation and Trico Electric Cooperative's 115 kV Sandario Project. In 2007 and 2008, I testified in the Palo Verde to

North Gila 500 kV project, 138 kV Vail to Cienega project and the Coolidge Station project.

During this time period of over twenty years at the Commission, I conducted engineering evaluations of electric utility rate cases and financing cases, such as those pertaining to Arizona Public Service Company, Tucson Electric Company ("TEP"), Salt River Project, Southwest Gas Company, Trico Electric Cooperative, Duncan Valley Electric Cooperative; Sulphur Springs Valley Electric Cooperative ("SSVEC"), Graham County Electric Cooperative ("GCEC"), and Graham County Utilities, Inc., Gas Division ("Graham") and Navopache Electric, Inc. ("NEC").

I inspected utility power plants including the Palo Verde Nuclear Generating Station. I was involved with the development of retail competition in Arizona and of DesertStar, an Independent System Operator ("ISO") for the desert 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 ("AISA") as an interim organization until commercial operation of DesertStar, which later evolved into WestConnect, a pseudo Regional Transmission Operator ("RTO").

From July 2001 to June 2002, I had my own consulting engineering firm, named P. K. Bahl & Associates. During that time, I was involved with deregulation of the electric power industry and the formation of RTO's, addressing the planning, congestion management, business practices and market monitoring activities of the then Northwest RTO and the MidWest ISO.

From July 1998 to August 2000, I worked as Chief Engineer at the Residential Utility Consumer Office. During that 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 the development of distributed generation in Arizona on system reliability, and modifications to interconnection standards currently specified by the jurisdictional utilities. I was a member of the AISA 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 ("NERC"). I also published and presented a number of technical papers at national and international conferences regarding transmission issues and distributed generation during the last thirty years.

Prior to my employment with the Commission, I worked as an electrical engineer with electric utilities and consulting firms in the transmission and generation planning areas for approximately thirty two years, including ten years' experience at the Punjab State Electricity Board ("PSEB") in India from 1960 to 1970. I worked as Executive Engineer at the PSEB from 1968 to 1970 prior to coming to the United States in 1970.

Q. As part of your assigned duties at the Commission, did you perform an 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.

Q. What is the purpose of your Direct Testimony?

A. The purpose of my testimony is to discuss Staff's review of Graham County Utilities, Inc. Gas Division ("Graham") Cost of Service Study ("COSS") for the rate case, and present the results of this review.

II. COST OF SERVICE STUDY - REVIEW PROCESS

Q. What does the COSS signify?

A. There are three steps in performing a COSS. They are: 1) functionalization; 2) classification; and 3) allocation. First, the COSS enables us to determine the system cost of service by classifying the utility's costs (investments and expenses) by function, such as customer-related, demand-related, and commodity-related functions. Second, the study breaks down these costs by customer classes to reflect as closely as possible the cost causation by respective customer classes. Third, the results of the COSS 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 COSS model?

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

Q. Did Staff conduct a separate independent COSS?

A. No. Staff did not conduct a separate independent COSS. Staff reviewed the COSS performed by Graham. Staff made some corrections in certain allocation factors in Schedules G-6 and G-8. The revised Schedule G-8 resulted in changes in other G

Schedules, such as G-1, G-2, G-6 and G-7. The results of Staff's COSS are attached to this testimony as Schedules G-1 thru G-8 under Exhibit 1.

Q. What was the process Staff used in reviewing Graham's COSS?

A. First, I reviewed the G Schedules reflecting various allocation factors in the COSS. Second, I reviewed the Test Year ("FYE September 30, 2011") rate base, revenues and expenses in the filed rate case.

III. ALLOCATION OF DISTRIBUTION MAINS AND SERVICES

Q. What comments does Staff have regarding Graham's allocation of Distribution Mains and Distribution Mains and Services?

A. Although, in Schedule G-8, the allocation factor F3 for Distribution Mains is 100 percent according to Demand, it was incorrectly applied in Schedule G-6 as 50 percent Demand and 50 percent Weighted Customers. It was corrected to 100 percent Demand.

In reference to the cost of Distribution Plant shown in Schedule G-6, the cost of Distribution Mains is $2,209,733, and the cost of Services is $909,642, resulting in their total cost of $3,119,375. Per Allocation Factor F3a, Graham allocated the cost of Distribution Mains and Services to 50 percent Demand, and the other 50 percent to the number of Weighted Customers. Staff corrected this allocation to 70.84 percent Demand and 29.1 percent Weighted Customers in proportion to the cost of Distribution Mains and Services stated above.

Application of factor F3a also impacted the Distribution Operating Expenses for Distribution Mains and Services in Schedule G-7, changing from 50 percent Demand and

50 percent Weighted Customers, respectively, to 70.84 percent Demand and 29.1 percent Weighted Customers.

Q. **Did Staff make any other change in Graham's allocation factors?**

A. Yes, Staff made the following additional changes and corrections in the COSS allocation factors.

- F6 ~ On Schedule G-7, F6 was mis-labeled, representing Meter Reading Expenses, and Meter Reading & installation. It should be designated as F6a, because it was derived and calculated differently from F6. It was changed to 53.40 percent Weighted Customers and 46.60 percent Customers.

- F6a ~ On Schedule G-8, F6a should be changed from 100 percent Customers to 53.40 percent Weighted Customers and 46.60 percent Customers.

- F7 was not calculated correctly in terms of allocating Depreciation on Mains according to 50 percent Demand and 50 percent Weighted Customers. F7 was changed to 47.26 percent Demand and 52.74 percent Weighted Customers.

- D-1 ~ On Schedule G-8, for Winter Peak Demand, replace 0.00 percent by 100 percent under the column entitled "Total."

Q. What is the effect of the above-noted changes In Allocation Factors?

A. These changes in the above noted allocation factors resulted in shifting of rate base from residential and irrigation customers to commercial customers. A corresponding shift of Operating expenses incurred from residential and irrigation customers to commercial customers. These shifts resulted in an increase in the rate of return on rate base for residential and irrigation customers and a decrease in the rate of return on rate base for commercial customers.

IV. CONCLUSIONS AND RECOMMENDATIONS

Q. Based upon your testimony, what are Staff's conclusions and recommendations regarding the COS study?

A. Based on the review of Graham's COSS, Staff's conclusions and recommendations are as follows:

1. It is Staff's conclusion that Graham performed the COSS consistent with the methodology generally accepted in the industry, and developed the allocation factors appropriately, except for certain allocation factors, which were modified by Staff.

2. Staff further concludes that, based on the evaluation of the COSS model utilized by Graham and the changes Staff made in the allocation factors stated above, the results of the COSS are satisfactory.

3. Staff recommends that Graham make the following changes in the COSS allocation factors.

- F3 ~ Distribution Mains should be allocated 100 percent to Demand. On Schedule G-6, F3 should be changed from 50 percent Demand and 50 percent Weighted Customers to 100 percent Demand.

- F3a ~ for Mains & Services should be changed from 50 percent Demand and 50 percent Weighted Customers to 70.84 percent Demand and 29.16 percent Weighted Customers, based on actual plant in service.

- F6 ~ On Schedule G-7, F6, representing Meter Reading Expenses and Meter Reading & installation, should be designated as F6a, and changed to 53.40 percent Weighted Customers and 46.60 percent Customers.

- F6a ~ On Schedule G-8, F6a should be changed from 100 percent Customers to 53.40 percent Weighted Customers and 46.60 percent Customers.

- F7 ~ allocating Depreciation on Mains should be corrected from 50 percent Demand and 50 percent Weighted Customers to 47.26 percent Demand and 52.74 percent Weighted Customers.

- D-1 ~ On Schedule G-8, for Winter Peak Demand, replace 0.00 percent by 100 percent under the column entitled "Total."

4. Staff further recommends that Graham should continue to utilize the current COSS model, including the revised allocation factors in Schedule G-8 in all future rate cases.

5. Staff further recommends that Graham's COSS cost allocations and factors be accepted with Staff's above noted revisions, which are reflected in Staff's COSS G-Schedules under attached Exhibit 1.

Q. Does this conclude your Direct Testimony?

A. Yes it does.

EXHIBIT 1

Graham County Utilities, Inc. Gas Division

Cost of Service Schedules G-1 Through G-8

GRAHAM COUNTY UTILITIES, INC. - GAS
COST OF SERVICE SUMMARY - PRESENT RATES
TEST FISCAL YEAR SEPTEMBER 30, 2011

DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	IRRIGATION
Operating Revenues	**3,242,352**	**2,421,838**	**808,496**	**12,018**
Operating Expenses:				
Purchased Gas	1,399,908	1,042,157	352,524	5,227
Distribution Expense - Operations	334,746	259,432	74,080	1,234
Distribution Expense - Maintenance	319,609	237,390	81,303	916
Customer Account Expense	323,758	302,195	20,874	689
Administrative & General Expense	434,785	357,659	75,969	1,157
Depreciation	147,629	115,055	32,013	561
Property Taxes	31,305	21,835	9,417	53
Tax Expense - Other	59,036	48,564	10,315	157
Interest Expense -Other	44,041	41,666	2,306	69
Total Operation Expenses	**3,094,817**	**2,425,953**	**658,801**	**10,063**
Operating Income (Loss)	**147,535**	**(4,115)**	**149,695**	**1,955**
Rate Base	**2,514,450**	**1,925,733**	**580,070**	**8,647**
% Return - Present Rates	**5.87%**	**-0.21%**	**25.81%**	**22.61%**
Return Index	**1.00**	**(0.04)**	**4.40**	**3.85**
Allocated Interest - Long-Term	**112,205**	**85,934**	**25,885**	**386**
Operating TIER - Present Rates	**1.31**	**(0.05)**	**5.78**	**5.07**

Date: January 30, 2013

GRAHAM COUNTY UTILITIES, INC. - GAS
COST OF SERVICE SUMMARY - PROPOSED RATES
TEST FISCAL YEAR SEPTEMBER 30, 2011

DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	IRRIGATION
Operating Revenues	**3,466,484**	**2,613,913**	**838,425**	**14,147**
Operating Expenses:				
Purchased Gas	1,399,908	1,042,157	352,524	5,227
Distribution Expense - Operations	334,746	259,432	74,080	1,234
Distribution Expense - Maintenance	319,609	237,390	81,303	916
Customer Account Expense	323,758	302,195	20,874	689
Administrative & General Expense	434,785	357,659	75,969	1,157
Depreciation	147,629	115,055	32,013	561
Property Taxes	31,305	21,835	9,417	53
Tax Expense - Other	59,036	48,564	10,315	157
Interest Expense -Other	44,041	41,666	2,306	69
Total Operation Expenses	**3,094,817**	**2,425,953**	**658,801**	**10,063**
Operating Income (Loss)	**371,667**	**187,960**	**179,624**	**4,084**
Rate Base	**2,514,450**	**1,925,733**	**580,070**	**8,647**
% Return - Proposed Rates	**14.78%**	**9.76%**	**30.97%**	**47.23%**
Return Index	**1.00**	**0.66**	**2.09**	**3.20**
Allocated Interest - Long-Term	**112,205**	**85,934**	**25,885**	**386**
Operating TIER - Proposed Rates	**3.31**	**2.19**	**6.94**	**10.58**

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2011
UNIT COSTS

DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	IRRIGATION
UNIT COSTS - PRESENT RATES:				
DEMAND				
Amount	703,158	563,186	138,895	1,076
Bills	61,183	57,912	3,181	90
Therms	2,871,512	1,960,668	892,780	18,064
Per Bill	11.49	9.72	43.66	11.96
Per Therms	0.2449	0.2872	0.1556	0.0596
COMMODITY:				
Amount	1,482,048	1,011,943	460,782	9,323
Per Therms	0.4875	0.4875	0.4875	0.4875
CUSTOMER:				
Amount	1,057,146	846,709	208,819	1,618
Per Bill	17.28	14.62	65.65	17.98
UNIT COSTS - PROPOSED RATES:				
DEMAND				
Amount	792,688	634,894	156,580	1,213
Per Bill	73.67	10.96	49.22	13.48
Per Therms	0.5664	0.3238	0.1754	0.0672
COMMODITY:				
Amount	1,482,048	1,011,943	460,782	9,323
Per Therms	0.4875	0.4875	0.4875	0.4875
CUSTOMER:				
Amount	1,191,748	954,517	235,407	1,824
Per Bill	110.76	16.48	74.00	20.27

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2011
ALLOCATION OF RATE BASE

			CONSUMER CLASS		
DESCRIPTION	**FACTOR**	**TOTAL**	**RESIDENTIAL**	**COMMERCIAL**	**IRRIGATION**
GROSS PLANT IN SERVICE:					
Demand	D-1	2,344,442	1,635,190	705,231	4,021
Commodity	CM-1	-			
Customer - Weighted	C-1	2,289,800	1,952,591	324,232	12,977
Customer - Unweighted	C-2	-			
Total		**4,634,242**	**3,587,781**	**1,029,463**	**16,998**
ACCUMULATED DEPRECIATION:					
Demand	D-1	1,087,187	758,286	327,037	1,864
Commodity	CM-1	-			
Customer - Weighted	C-1	1,213,119	1,034,468	171,776	6,875
Customer - Unweighted	C-2	-			
Total		**2,300,306**	**1,792,754**	**498,813**	**8,739**
NET PLANT IN SERVICE		**2,333,936**	**1,795,027**	**530,650**	**8,259**
CWIP:					
Demand	D-1	107,028	74,649	32,195	184
Commodity	CM-1	-			
Customer - Weighted	C-1	104,531	89,137	14,802	592
Customer - Unweighted	C-2	-			
Total		**211,559**	**163,786**	**46,997**	**776**
WORKING CAPITAL:					
Demand	D-1	46,625	32,520	14,025	80
Commodity	CM-1	-	-	-	-
Customer - Weighted	C-1	(17,800)	(15,179)	(2,520)	(101)
Customer - Unweighted	C-2	6,775	6,409	355	11
Total		**35,600**	**23,750**	**11,860**	**(10)**
LESS:					
CONSUMER DEPOSITS	C-1	**66,645**	**56,830**	**9,437**	**378**
TOTAL RATE BASE		**2,514,450**	**1,925,733**	**580,070**	**8,647**

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2011
ALLOCATION OF INCOME STATEMENT

			CONSUMER CLASS (PRESENT)				CONSUMER CLASS (PROPOSED)		
DESCRIPTION	**FACTOR**	**TOTAL**	**RESIDENTIAL**	**COMMERCIAL**	**IRRIGATION**	**TOTAL**	**RESIDENTIAL**	**COMMERCIAL**	**IRRIGATION**
REVENUES:									
Gas Sales - Adjusted		3,202,309	2,383,955	806,399	11,955	3,426,441	2,576,030	836,328	14,084
Service Charges & Other Revenues	C-2	40,043	37,883	2,097	63	40,043	37,883	2,097	63
Total		**3,242,352**	**2,421,838**	**808,496**	**12,018**	**3,466,484**	**2,613,913**	**838,425**	**14,147**
OPERATING EXPENSE:									
Purchased Gas	CM-1	**1,399,908**	**1,042,157**	**352,524**	**5,227**				
Distribution Expense - Operations:									
Demand	D-1	167,577	116,881	50,409	287				
Commodity	CM-1	-							
Customer - Weighted	C-1	167,169	142,551	23,671	947				
Customer - Unweighted	C-2	-							
Total		**334,746**	**259,432**	**74,080**	**1,234**				
Distribution Expense - Maintenance:									
Demand	D-1	226,408	157,914	68,106	388				
Commodity	CM-1	-							
Customer - Weighted	C-1	93,201	79,476	13,197	528				
Customer - Unweighted	C-2	-							
Total		**319,609**	**237,390**	**81,303**	**916**				
Customer Accounts Expense:									
Demand	D-1	-							
Commodity	CM-1	-							
Customer - Weighted	C-1	-							
Customer - Unweighted	C-2	323,758	302,195	20,874	689				
Total		**323,758**	**302,195**	**20,874**	**689**				
Admin. & General Expense:									
Demand	D-1	174,754	121,886	52,568	300				
Commodity	CM-1	-	-	-	-				
Customer - Weighted	C-1	109,656	93,508	15,527	621				
Customer - Unweighted	C-2	150,375	142,265	7,874	236				
Total		**434,785**	**357,659**	**75,969**	**1,157**				

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2011
FUNCTION OF RATE BASE COMPONENTS

DESCRIPTION	FACTOR	TOTAL	FUNCTION	SPECIFIC	DEMAND	COMMODITY	CUST. - WT	CUST.
GROSS UTILITY PLANT IN SERVICE								
Distribution Plant:								
Distribution Mains	F-3	2,209,733	2,209,733		2,209,733		-	
Org. & Land & Land Rights	F-3a	44,016	44,016		31,180		12,836	
Services	F-4	909,642	909,642				909,642	
Meters & Regulators	F-5	1,266,208	1,266,208				1,266,208	
Total Distribution Plant		**4,429,599**	**4,429,599**	**-**	**2,240,913**	**-**	**2,188,686**	**-**
Percent	F10	**100.00%**	**100.00%**	**0.00%**	**50.59%**	**0.00%**	**49.41%**	**0.00%**
General Plant:								
Structures & Improvements	F10	3,309	3,309		1,674		1,635	
Office Equipment	F10	2,750	2,750		1,391		1,359	
Transportation Equipment		-	-		-		-	
Tools & Shop Equipment	F10	132,576	132,576		67,070		65,506	
Power Operated Equipment	F10	66,009	66,009		33,394		32,615	
Total General Plant		**204,644**	**204,644**	**-**	**103,528**	**-**	**101,116**	**-**
Percent	F10	**100.00%**	**100.00%**	**0.00%**	**50.59%**	**0.00%**	**49.41%**	**0.00%**
GROSS PLANT IN SERVICE		**4,634,243**	**4,634,243**	**-**	**2,344,442**	**-**	**2,289,801**	**-**
PERCENT	F10	**100.00%**	**100.00%**	**0.00%**	**50.59%**	**0.00%**	**49.41%**	**0.00%**
ACCUMULATED DEPRECIATION:								
Distribution Plant	F-7	2,129,775	2,129,775	-	1,006,589	-	1,123,186	-
General Plant	F-7	170,531	170,531	-	80,598	-	89,933	-
Total Accumulated Depreciation		**2,300,306**	**2,300,306**	**-**	**1,087,187**	**-**	**1,213,119**	**-**
CWIP		**211,559**		**211,559**	**107,027**		**104,532**	
WORKING CAPITAL:								
Materials & Supplies Inventory	F-7	79,032	79,032		37,353	-	41,679	-
Prepaids	F-9	23,205	23,213		9,273	-	7,166	6,775
Consumer Deposits		(66,645)	(66,645)				(66,645)	
Total Working Capital		**35,592**	**35,600**	**-**	**46,625**	**-**	**(17,800)**	**6,775**
TOTAL RATE BASE		**2,581,088**	**2,369,537**	**211,559**	**1,410,907**	**-**	**1,163,414**	**6,775**

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2011
FUNCTION OF OPERATING EXPENSES

DESCRIPTION	FACTOR	TOTAL	FUNCTION	DEMAND	COMMODITY	CUST. - WT	CUST.
Purchased Gas	F-2	**1,399,908**	**1,399,908**		**1,399,908**		
Distribution Operating Expenses:							
Supervision & Engineering	F-3a	46,915	46,915	33,234		13,681	
Mains & Services	F-3a	138,508	138,508	98,117		40,390	
Measuring & Reg Stations	F-1	2,339	2,339	2,339			
Customer Installations	F-4	99,148	99,148			99,148	
Other Operating Expenses	F-3a	47,837	47,837	33,887		13,950	
Total Operating Expenses		**334,747**	**334,747**	**167,578**	**-**	**167,169**	**-**
Distribution Maint. Expenses:							
Supervision & Engineering	F-3a	19,669	19,669	13,934		5,736	
Maintainance Expenses	F-3a	299,940	299,940	212,475		87,466	
Total Maint. Expenses		**319,610**	**319,610**	**226,408**	**-**	**93,202**	**-**
Meter Reading Expenses	F-6a	82,279	82,279			43,936	38,343
Customer Accounting & Info. Exp.	F-6	209,903	209,903				209,903
Delinquent Accts. & Uncollectible	F-6	31,577	31,577				31,577
Total Customer Accounts Expenses:		**323,759**	**323,759**	**-**	**-**	**43,936**	**279,823**
Administrative & General Exp.	F-8	434,786	434,786	174,754	-	109,657	150,376
Depreciation	F-7	147,019	147,630	69,774		77,856	
Property Taxes	F-7	31,306	31,306	14,796		16,510	
Taxes - Other	F-8	59,035	59,035	23,728	-	14,889	20,418
Interest Expense - Other	F-6	44,042	44,042				44,042
TOTAL OPERATING EXPENSES		**3,094,211**	**3,094,822**	**677,038**	**1,399,908**	**523,218**	**494,658**
FUNCT. OF SALARIES & WAGES							
Operating Expenses	F-3a	143,568	143,568	101,702		41,866	
Maintenance Expenses	F-3a	133,201	133,201	94,358		38,843	
Meter Reading & Installation	F-6a	79,250	79,250			42,318	36,932
Customer Accounting	F-6	131,778	131,778				131,778
Total		**487,796**	**487,796**	**196,060**	**-**	**123,027**	**168,710**
Percent	F-8	**100.00%**	**100.00%**	**40.19%**	**0.00%**	**25.22%**	**34.59%**
FUNCTION OF O&M LESS PG		1,694,303	1,694,914	677,038	-	523,218	494,658
Percent	F-9	**100.00%**	**100.04%**	**39.96%**	**0.00%**	**30.88%**	**29.20%**
Percent		**100.00%**		**39.95%**		**30.87%**	**29.18%**
	F-6a					53.40%	46.60%

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2011
ALLOCATION FACTORS

FUNCTION FACTOR	DESCRIPTION	TOTAL	DEMAND	COMMODITY	WEIGHTED CUSTOMER	CUSTOMER
F-1	Demand	100.00%	100.00%			
F-2	Commodity	100.00%		100.00%		
F-3	Distribution Mains	100.00%	100.00%			
F-3a	Mains & Services	100.00%	70.84%		29.16%	
F-4	Services	100.00%			100.00%	
F-5	Meters & regulators	100.00%			100.00%	
F-6	Customer Accounts	100.00%				100.00%
F-6a	Customer Weighted/Customer	100.00%			53.40%	46.60%
DERIVED FUNCTION FACTOR	**DESCRIPTION**					
F-7	Gross Plant in Service	100.00%	47.26%		52.74%	
F-8	Salaries & Wages	100.00%	40.19%	0.00%	25.22%	34.59%
F-9	O & M Less Purchased gas	100.04%	39.96%	0.00%	30.88%	29.20%

CLASS ALLOCATION FACTORS	DESCRIPTION	TOTAL	CUSTOMER CLASS RESID.	COMM.	IRRIG.
D-1	Winter Peak Demand	100.000%	69.748%	30.081%	0.171%
CM-1	Commodity	100.000%	74.445%	25.182%	0.373%
C-1	Customer - Weighted	100.000%	85.273%	14.160%	0.567%
C-2	Customer - Unweighted	100.000%	94.606%	5.237%	0.157%