Transcript Exhibit(s)

Docket #(s): G-04204A-08-0571

Exhibit # : S1-S4, S6-S15, UNSG1-UNSG12

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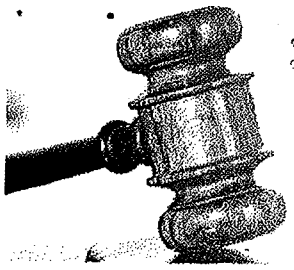


Regulatory Research Associates
REGULATORY FOCUS

January 12, 2009

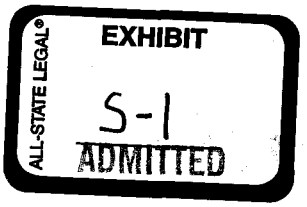
MAJOR RATE CASE DECISIONS--JANUARY 2007-DECEMBER 2008 SUPPLEMENTAL STUDY

This Supplemental Study was prepared in conjunction with the Special Report entitled *Major Rate Case Decisions--January 1990-December 2007* that was uploaded to our website on Jan. 8. This study contains chronological listings of all major electric and gas cases decided during the years 2007 and 2008. These listings, with key data concerning each case, appear on pages 5 through 11 of this report. Tables summarizing industry-wide concerning cases decided in past years appear on pages 2 and 3. The average return on equity (ROE) authorized electric utilities in 2008 approximated 10.5%, compared to 10.4% in 2007. There were 37 electric ROE determinations in 2007, and 39 in 2007. The average ROE authorized gas utilities approximated 10.4% in 2008, compared to 10.2% in 2007. There were 30 gas cases that included an ROE determination in 2008, and 37 in 2007. We note that these ROEs are simple, non-weighted averages. Not included in these averages is a Sept. 17, 2008 steam rate case decision for Consolidated Edison of New York, in which the New York Public Service Commission adopted a settlement that incorporated a 9.3% return on common equity (48% of capital) and a 7.5% return on rate base.

After reaching a low in the late-1990's and early-2000's, the number of equity return determinations for energy companies has generally increased over the last several years. The total number of electric and gas equity return determinations in 2008 (67) was 180% greater than the number in 2000 (24). Increased costs, including environmental compliance expenditures, and the need for generation and delivery system infrastructure upgrades and expansion at many companies argue for a continuation of the increased level of rate case activity over the next several years. However, cost efficiencies from technological improvements, the use of multi-year settlements that do not specify return parameters, and a reduced number of companies due to mergers may prevent the number of rate cases and equity return determinations from significantly increasing further. We note that electric industry restructuring in many states has led to the unbundling of rates, with state commissions authorizing revenue requirement and return parameters for delivery operations only (which we footnote in our chronology), thus complicating historical data comparability. We also note that the financial crisis that began in September 2008 and the resulting significant increase in non-U.S. Treasury debt yields may indicate that utility equity costs have increased and lead to higher authorized ROEs by commissions.

The individual electric and gas cases listed on pages 5 through 11 are presented with the decision date shown first, followed by the company name, the abbreviation of the state issuing the decision, the authorized rate of return (ROR) and ROE, and the common equity component of the adopted capital structure. If the capital structure included cost-free capital or investment tax credit balances at the overall rate of return, an asterisk (*) follows the number in this column. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base valuation, and the amount of the permanent rate change authorized. Fuel adjustment clause and other rider-related rate changes are not reflected in this study.

The table on page 2 shows the average ROE authorized annually since 1990, and by quarter since 2002, in major electric and gas rate decisions, followed by the number of observations in each period. The tables on page 3 show the composite electric and gas industry data for all the cases included in the chronology of this and earlier reports, summarized annually since 1995 and by quarter for the past eight quarters.



(Text continued on page 4.)

Average Equity Returns Authorized January 1990 - December 2008

Year	Period	Electric Utilities ROE %	(# Cases)	Gas Utilities ROE %	(# Cases)
1990	Full Year	12.70	(44)	12.67	(31)
1991	Full Year	12.55	(45)	12.46	(35)
1992	Full Year	12.09	(48)	12.01	(29)
1993	Full Year	11.41	(32)	11.35	(45)
1994	Full Year	11.34	(31)	11.35	(28)
1995	Full Year	11.55	(33)	11.43	(16)
1996	Full Year	11.39	(22)	11.19	(20)
1997	Full Year	11.40	(11)	11.29	(13)
1998	Full Year	11.66	(10)	11.51	(10)
1999	Full Year	10.77	(20)	10.66	(9)
2000	Full Year	11.43	(12)	11.39	(12)
2001	Full Year	11.09	(18)	10.95	(7)
	1st Quarter	10.87	(5)	10.67	(3)
	2nd Quarter	11.41	(6)	11.64	(4)
	3rd Quarter	11.06	(4)	11.50	(3)
	4th Quarter	11.20	(7)	10.78	(11)
2002	**Full Year**	**11.16**	(22)	**11.03**	(21)
	1st Quarter	11.47	(7)	11.38	(5)
	2nd Quarter	11.16	(4)	11.36	(4)
	3rd Quarter	9.95	(5)	10.61	(5)
	4th Quarter	11.09	(6)	10.84	(11)
2003	**Full Year**	**10.97**	(22)	**10.99**	(25)
	1st Quarter	11.00	(3)	11.10	(4)
	2nd Quarter	10.54	(6)	10.25	(2)
	3rd Quarter	10.33	(2)	10.37	(8)
	4th Quarter	10.91	(8)	10.66	(6)
2004	**Full Year**	**10.75**	(19)	**10.59**	(20)
	1st Quarter	10.51	(7)	10.65	(2)
	2nd Quarter	10.05	(7)	10.54	(5)
	3rd Quarter	10.84	(4)	10.47	(5)
	4th Quarter	10.75	(11)	10.40	(14)
2005	**Full Year**	**10.54**	(29)	**10.46**	(26)
	1st Quarter	10.38	(3)	10.63	(6)
	2nd Quarter	10.68	(6)	10.50	(2)
	3rd Quarter	10.06	(7)	10.45	(3)
	4th Quarter	10.39	(10)	10.14	(5)
2006	**Full Year**	**10.36**	(26)	**10.43**	(16)
	1st Quarter	10.27	(8)	10.44	(10)
	2nd Quarter	10.27	(11)	10.12	(4)
	3rd Quarter	10.02	(4)	10.03	(8)
	4th Quarter	10.56	(16)	10.27	(15)
2007	**Full Year**	**10.36**	(39)	**10.24**	(37)
	1st Quarter	10.45	(10)	10.38	(7)
	2nd Quarter	10.57	(8)	10.17	(3)
	3rd Quarter	10.47	(11)	10.49	(7)
	4th Quarter	10.33	(8)	10.34	(13)
2008	**Full Year**	**10.46**	(37)	**10.37**	(30)

RRA

Electric Utilities--Summary Table*

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Eq. as % Cap. Struc.	(# Cases)	Amt. $ Mil.	(# Cases)
1995	Full Year	9.44	(30)	11.55	(33)	45.90	(30)	455.7	(43)
1996	Full Year	9.21	(20)	11.39	(22)	44.34	(20)	-5.6	(38)
1997	Full Year	9.16	(12)	11.40	(11)	48.79	(11)	-553.3	(33)
1998	Full Year	9.44	(9)	11.66	(10)	46.14	(8)	-429.3	(31)
1999	Full Year	8.81	(18)	10.77	(20)	45.08	(17)	-1683.8	(30)
2000	Full Year	9.20	(12)	11.43	(12)	48.85	(12)	-291.4	(34)
2001	Full Year	8.93	(15)	11.09	(18)	47.20	(13)	14.2	(21)
2002	Full Year	8.72	(20)	11.16	(22)	46.27	(19)	-475.4	(24)
2003	Full Year	8.86	(20)	10.97	(22)	49.41	(19)	313.8	(12)
2004	Full Year	8.44	(18)	10.75	(19)	46.84	(17)	1091.5	(30)
2005	Full Year	8.30	(26)	10.54	(29)	46.73	(27)	1373.7	(36)
2006	Full Year	8.24	(24)	10.36	(26)	48.67	(23)	1465.0	(42)
	1st Quarter	8.44	(8)	10.27	(8)	47.80	(8)	403.5	(9)
	2nd Quarter	7.94	(11)	10.27	(11)	46.02	(11)	718.6	(12)
	3rd Quarter	7.90	(4)	10.02	(4)	48.34	(4)	119.1	(6)
	4th Quarter	8.38	(15)	10.56	(16)	49.59	(14)	160.7	(19)
2007	Full Year	8.22	(38)	10.36	(39)	48.01	(37)	1401.9	(46)
	1st Quarter	8.36	(9)	10.45	(10)	49.25	(8)	802.9	(9)
	2nd Quarter	8.21	(7)	10.57	(8)	47.64	(7)	510.5	(8)
	3rd Quarter	8.32	(10)	10.47	(11)	48.96	(10)	737.5	(13)
	4th Quarter	8.09	(9)	10.33	(8)	47.58	(8)	848.5	(12)
2008	**Full Year**	**8.25**	**(35)**	**10.46**	**(37)**	**48.41**	**(33)**	**2899.4**	**(42)**

Gas Utilities--Summary Table*

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Eq. as % Cap. Struc.	(# Cases)	Amt. $ Mil.	(# Cases)
1995	Full Year	9.64	(16)	11.43	(16)	49.98	(15)	-61.5	(31)
1996	Full Year	9.25	(23)	11.19	(20)	47.69	(19)	193.4	(34)
1997	Full Year	9.13	(13)	11.29	(13)	47.78	(11)	-82.5	(21)
1998	Full Year	9.46	(10)	11.51	10)	49.50	(10)	93.9	(20)
1999	Full Year	8.86	(9)	10.66	(9)	49.06	(9)	51.0	(14)
2000	Full Year	9.33	(13)	11.39	(12)	48.59	(12)	135.9	(20)
2001	Full Year	8.51	(6)	10.95	(7)	43.96	(5)	114.0	(11)
2002	Full Year	8.80	(20)	11.03	(21)	48.29	(18)	303.6	(26)
2003	Full Year	8.75	(22)	10.99	(25)	49.93	(22)	260.1	(30)
2004	Full Year	8.34	(21)	10.59	(20)	45.90	(20)	303.5	(31)
2005	Full Year	8.25	(29)	10.46	(26)	48.66	(24)	458.4	(34)
2006	Full Year	8.51	(16)	10.43	(16)	47.43	(16)	444.0	(25)
	1st Quarter	8.40	(10)	10.44	(10)	48.33	(9)	158.4	(13)
	2nd Quarter	8.32	(3)	10.12	(4)	49.67	(4)	37.3	(5)
	3rd Quarter	7.88	(7)	10.03	(8)	48.70	(6)	402.0	(12)
	4th Quarter	7.97	(12)	10.27	(15)	47.74	(11)	215.7	(18)
2007	Full Year	8.12	(32)	10.24	(37)	48.37	(30)	813.4	(48)
	1st Quarter	8.78	(7)	10.38	(7)	52.07	(7)	129.6	(7)
	2nd Quarter	8.28	(3)	10.17	(3)	51.80	(3)	52.0	(4)
	3rd Quarter	8.33	(7)	10.49	(7)	50.58	(7)	312.8	(10)
	4th Quarter	8.45	(13)	10.34	(13)	49.25	(13)	390.4	(20)
2008	**Full Year**	**8.48**	**(30)**	**10.37**	**(30)**	**50.47**	**(30)**	**884.8**	**(41)**

* Number of observations in each period indicated in parentheses.

The table below tracks the average equity return authorized for all electric and gas rate cases combined, by year, for the last 19 years. As the table reveals, since 1990 authorized ROEs have generally trended downward, reflecting the significant decline in interest rates that has occurred over this time frame. The combined average equity returns authorized for electric and gas utilities in each of the years 1990 through 2008, and the number of observations for each year are as follows:

1990	12.69%	(75)	2000	11.41	(24)
1991	12.51	(80)	2001	11.05	(25)
1992	12.06	(77)	2002	11.10	(43)
1993	11.37	(77)	2003	10.98	(47)
1994	11.34	(59)	2004	10.67	(39)
1995	11.51	(49)	2005	10.50	(55)
1996	11.29	(42)	2006	10.39	(40)
1997	11.34	(24)	2007	10.30	(76)
1998	11.59	(20)	2008	10.42	(67)
1999	10.74	(29)			

Dennis Sperduto

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ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %		ROE %		Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/5/07	Oklahoma Gas & Electric (AR)	5.36		10.00		32.33 *	12/05-YE	5.4 (B)
1/5/07	Puget Sound Energy (WA)	8.40		10.40		44.00	9/05-A	-22.8
1/11/07	Metropolitan Edison (PA)	7.52		10.10		49.00	12/06-YE	58.7 (D)
1/11/07	Pennsylvania Electric (PA)	7.92		10.10		49.00	12/06-YE	50.2 (D)
1/11/07	Wisconsin Public Service (WI)	12.93		10.90		57.46	12/07-A/P	56.7
1/12/07	Portland General Electric (OR)	8.29		10.10		50.00 (Hy)	12/07-A	20.5 (Z)
1/19/07	Wisconsin Power and Light (WI)	9.27		10.80		54.13	12/07-A/P	36.2
3/21/07	Pacific Gas and Electric (CA)	---		---		---	12/07-A	192.2 (B,1)
3/22/07	Rockland Electric (NJ)	7.83		9.75		46.51	12/06-YE	6.4 (B,D)
2007	***1ST QUARTER: AVERAGES/TOTAL***	**8.44**		**10.27**		**47.80**		**403.5**
	MEDIAN	**8.11**		**10.10**		**49.00**		**---**
	OBSERVATIONS	**8**		**8**		**8**		**9**
5/15/07	Appalachian Power (VA)	7.36		10.00		41.11 *	12/05-YE	24.0
5/17/07	Aquila (MPS) (MO)	8.39		10.25		48.17	12/05-YE	45.2
5/17/07	Aquila (L&P) (MO)	8.93		10.25		48.17	12/05-YE	13.6
5/22/07	Monongahela Pow./Potomac Ed. (WV)	8.44		10.50		46.07	12/05-YE	-6.2
5/22/07	Union Electric (MO)	7.94		10.20		52.22	6/06-YE	41.8
5/23/07	Nevada Power (NV)	9.06		10.70		47.29	6/06-YE	120.5
5/24/07	AEP Texas North (TX)	---		---		---	6/06-YE	13.7 (B,D)
5/25/07	Public Service of New Hampshire (NH)	7.55		9.67		47.66	12/05-A	50.1 (B,I,D)
6/15/07	Entergy Arkansas (AR)	5.58		9.90		32.19 *	6/06-YE	-5.7
6/21/07	PacifiCorp (WA)	8.06		10.20		46.00	3/06-A	14.4 (R)
6/22/07	Appalachian Power (WV)	7.67	(E)	10.50	(E)	42.88 (E)	12/06-YE	85.5 (B,Z)
6/28/07	Arizona Public Service (AZ)	8.32		10.75		54.50	9/05-YE	321.7
2007	***2ND QUARTER: AVERAGES/TOTAL***	**7.94**		**10.27**		**46.02**		**718.6**
	MEDIAN	**8.06**		**10.25**		**47.29**		**---**
	OBSERVATIONS	**11**		**11**		**11**		**12**
7/3/07	El Paso Electric (NM)	---		---		---	12/05-YE	5.5 (B)
7/12/07	Granite State Electric (NH)	8.61		9.67		50.00 (Hy)	---	-2.2 (B,D,Z)
7/19/07	Delmarva Power & Light (MD)	7.68		10.00		48.63	9/06-A	14.9 (D,2)
7/19/07	Potomac Electric Power (MD)	7.99		10.00		47.69	9/06-A	10.6 (D,2)
7/27/07	Southwestern Public Service (TX)	---		---		---	9/05-YE	23.0 (B)
8/15/07	Southern Indiana Gas & Electric (IN)	7.32		10.40		47.05 *	3/06-YE	67.3 (B)
2007	***3RD QUARTER: AVERAGES/TOTAL***	**7.90**		**10.02**		**48.34**		**119.1**
	MEDIAN	**7.84**		**10.00**		**48.16**		**---**
	OBSERVATIONS	**4**		**4**		**4**		**6**
10/9/07	Public Service of Oklahoma (OK)	8.01		10.00		46.02	6/06-YE	9.8 (I)
10/18/07	Orange and Rockland Utilities (NY)	7.56		9.10		47.54	6/08-A	0.0
10/31/07	Electric Transmission Texas (TX)	7.88	(R)	9.96		40.00 (Hy)	6/08-YE	12.0 (R,Tr,3)

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
11/20/07	Kansas City Power & Light (KS)	---	---	---	---	28.0 (B)
11/29/07	Cheyenne Light, Fuel & Power (WY)	8.84	10.90	54.00 (Hy)	9/06-YE	6.7 (B)
11/29/07	Wisconsin Power and Light (WI)	---	---	---	12/08-A	25.8 (4)
12/6/07	Kansas City Power & Light (MO)	8.68	10.75	57.62	12/06-YE	35.3
12/6/07	PPL Electric Utilities (PA)	---	---	---	12/07-YE	55.0 (B,D)
12/13/07	AEP Texas Central (TX)	7.50	9.96	40.00 (Hy)	6/06-YE	40.8 (I,D)
12/14/07	Madison Gas and Electric (WI)	9.08	10.80	57.36	12/08-A/P	16.2
12/14/07	South Carolina Electric & Gas (SC)	8.62	10.70	53.32	3/07-YE	76.9 (B)
12/19/07	Avista Corporation (WA)	8.20	10.20	46.00	12/06-A	30.2 (B)
12/20/07	Duke Energy Carolinas (NC)	8.57	11.00	53.00	12/06-YE	-286.9 (Bp)
12/20/07	Bangor Hydro-Electric (ME)	8.60	10.20	---	---	1.1 (B,D)
12/21/07	Pacific Gas and Electric (CA)	8.79	11.35	52.00	12/08-A	0.0
12/21/07	San Diego Gas & Electric (CA)	8.40	11.10	49.00	12/08-A	8.2
12/21/07	Southern California Edison (CA)	8.75	11.50	48.00	12/08-A	-9.6
12/28/07	PacifiCorp (ID)	8.27	10.25	50.40	12/06	11.5 (B)
12/31/07	Georgia Power (GA)	---	11.25	---	7/08-A	99.7 (B)
2007	***4TH QUARTER: AVERAGES/TOTAL***	**8.38**	**10.56**	**49.59**		**160.7**
	MEDIAN	**8.57**	**10.73**	**49.70**		**---**
	OBSERVATIONS	**15**	**16**	**14**		**19**
2007	***FULL YEAR: AVERAGES/TOTAL***	**8.22**	**10.36**	**48.01**		**1401.9**
	MEDIAN	**8.28**	**10.25**	**48.17**		**---**
	OBSERVATIONS	**38**	**39**	**37**		**46**
1/8/08	Northern States Power-Wisconsin (WI)	9.67	10.75	52.51	12/08-A	39.4
1/17/08	Wisconsin Electric Power (WI)	9.26	10.75	54.36	12/08-A/P	148.4 (Z)
1/28/08	Connecticut Light & Power (CT)	7.72	9.40	48.99	12/06-YE	97.9 (D,Z)
1/30/08	Potomac Electric Power (DC)	7.96	10.00	46.55	2/07-A	28.3 (D,S)
1/31/08	Central Vermont Public Service (VT)	8.50	10.21 (R)	50.02	12/06-A	6.4 (B)
2/6/08	Interstate Power & Light (IA)	---	11.70 (6)	---	---	---
2/28/08	Idaho Power (ID)	8.10	---	---	---	32.1 (B)
2/29/08	Fitchburg Gas & Electric (MA)	8.38	10.25	42.80	12/06-YE	2.1 (D)
3/12/08	PacifiCorp (WY)	8.29	10.25	50.80	8/08	23.0 (B,7)
3/25/08	Consolidated Edison of New York (NY)	7.34	9.10	47.98	3/09-A	425.3 (D)
3/31/08	Virginia Electric Power (VA)	---	12.12 (8)	---	---	---
2008	***1ST QUARTER: AVERAGES/TOTAL***	**8.36**	**10.45**	**49.25**		**802.9**
	MEDIAN	**8.29**	**10.25**	**49.51**		**---**
	OBSERVATIONS	**9**	**10**	**8**		**9**
4/22/08	MDU Resources (MT)	8.58	10.25	50.67	12/06-A	4.1 (B,Z)
4/24/08	Public Service Co. of New Mexico (NM)	8.24	10.10	51.37	9/06-YE	34.4
5/1/08	Hawaiian Electric Company (HI)	8.66	10.70	55.79	12/05-A	44.9 (Bp,I)
5/27/08	UNS Electric (AZ)	9.02	10.00	48.85	6/06-YE	4.0
5/30/08	Idaho Power (ID)	--- (9)	---	---	---	8.9

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
6/10/08	Consumers Energy (MI)	6.93	10.70	41.75 *	12/08-A	221.0 (I)
6/16/08	MidAmerican Energy (IA)	---	11.70 (B,10)	---	---	---
6/27/08	Appalachian Power (WV)	7.65	10.50	41.54	12/07-YE	106.1 (B)
6/27/08	Sierra Pacific Power (NV)	8.41	10.60 (11)	43.49	6/07-YE	87.1
6/30/08	Oncor Electric Delivery (TX)	---	---	---	12/06	--- (D,12)
2008	***2ND QUARTER: AVERAGES/TOTAL***	**8.21**	**10.57**	**47.64**		**510.5**
	MEDIAN	**8.41**	**10.55**	**48.85**		**---**
	OBSERVATIONS	**7**	**8**	**7**		**8**
7/1/08	Central Maine Power (ME)	---	---	---	---	-20.3 (B,D,13)
7/2/08	NorthWestern Corporation (MT)	--- (14)	---	---	---	10.0 (B,I)
7/10/08	Otter Tail Corporation (MN)	8.33	10.43	50.00	12/06-A	3.8 (I)
7/16/08	Orange and Rockland Utilities (NY)	7.69	9.40	48.00	6/09-A	15.6 (B,D)
7/30/08	Empire District Electric (MO)	8.92	10.80	50.78	6/07-YE	22.0
7/31/08	San Diego Gas & Electric (CA)	--- (15)	--- (15)	--- (15)	12/08-A	234.0 (B,Z)
8/11/08	PacifiCorp (UT)	8.29	10.25	50.40	12/08-A	39.4 (R)
8/26/08	Southwestern Public Service (NM)	8.27	10.18	51.23	12/06-YE	13.1
8/27/08	MidAmerican Energy (IA)	---	11.70 (B,16)	---	---	---
9/10/08	Commonwealth Edison (IL)	8.36	10.30	45.04	12/06-YE	273.6 (D)
9/24/08	Central Illinois Light (IL)	8.01	10.65	46.50	12/06-YE	-2.8 (D)
9/24/08	Central Illinois Public Service (IL)	8.20	10.65	47.91	12/06-YE	22.0 (D)
9/24/08	Illinois Power (IL)	8.68	10.65	51.76	12/06-YE	103.9 (D)
9/30/08	Avista Corp. (ID)	8.45	10.20	47.94	12/07-A	23.2 (B)
2008	***3RD QUARTER: AVERAGES/TOTAL***	**8.32**	**10.47**	**48.96**		**737.5**
	MEDIAN	**8.31**	**10.43**	**49.00**		**---**
	OBSERVATIONS	**10**	**11**	**10**		**13**
10/8/08	PacifiCorp (WA)	8.06	---	---	---	20.4 (B)
10/8/08	Puget Sound Energy (WA)	8.25	10.15	46.00	9/07-A	130.2 (B)
11/13/08	NorthWestern Corporation (MT)	8.25 (17)	10.00 (17)	50.00 (17)	---	---
11/17/08	Appalachian Power (VA)	7.69	10.20	---	12/07	167.9 (I,B)
12/1/08	Tucson Electric Power (AZ)	8.03	10.25	42.50	12/06-YE	136.8 (B)
12/17/08	Duke Energy Ohio (OH)	---	---	---	---	98.0 (B,Gn,E,Z)
12/18/08	Madison Gas and Electric (WI)	---	---	---	12/09	-2.7
12/23/08	Detroit Edison (MI)	7.16	11.00	40.68 *	12/09-A	83.6
12/29/08	Portland General Electric (OR)	8.33	10.10 (Bp)	50.00	12/09-A	121.0
12/29/08	Avista Corporation (WA)	8.22	10.20	46.30	12/07-A	32.5 (B)
12/30/08	Wisconsin Power and Light (WI)	---	---	---	12/09	0.0 (B)
12/30/08	Wisconsin Public Service (WI)	---	---	53.41	12/09	48.0 (B,18)
12/31/08	Northern States Power (ND)	8.80	10.75	51.77	12/08	12.8 (I,B)
2008	***4TH QUARTER: AVERAGES/TOTAL***	**8.09**	**10.33**	**47.58**		**848.5**
	MEDIAN	**8.22**	**10.20**	**48.15**		**---**
	OBSERVATIONS	**9**	**8**	**8**		**12**
2008	***YEAR-TO-DATE: AVERAGES/TOTAL***	**8.25**	**10.46**	**48.41**		**2899.4**
	MEDIAN	**8.27**	**10.25**	**48.99**		**---**
	OBSERVATIONS	**35**	**37**	**33**		**42**

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/5/07	Puget Sound Energy (WA)	8.40	10.40	44.00	9/05-A	29.5
1/9/07	SEMCO Energy Gas (MI)	7.75	11.00	42.94 *	---	12.6 (B)
1/11/07	Wisconsin Public Service (WI)	8.62	10.90	57.46	12/07-A/P	18.9
1/12/07	Cascade Natural Gas (WA)	8.85	---	---	---	7.1 (B)
1/19/07	Wisconsin Power and Light (WI)	9.15	10.80	54.13	12/07-A/P	-1.9
1/26/07	Fitchburg Gas & Electric (MA)	---	10.00	---	---	2.2 (B,Z)
2/8/07	PPL Gas Utilities (PA)	8.44	10.40	51.79 (Hy)	12/06-YE	8.1
3/14/07	Connecticut Natural Gas (CT)	8.60	10.10	53.60	3/06-YE	14.4 (B)
3/15/07	Union Electric (MO)	---	---	---	---	6.0 (B)
3/20/07	Delmarva Power & Light (DE)	7.73	10.25	46.90	3/06-A	9.0 (B,I)
3/21/07	Pacific Gas and Electric (CA)	---	---	---	12/07-A	20.5 (B,1)
3/22/07	Southern Union (MO)	8.60	10.50	36.06 (19)	12/05-YE	27.2
3/29/07	Atmos Energy (TX)	7.90	10.00	48.10	12/05-YE	4.8
2007	***1ST QUARTER: AVERAGES/TOTAL***	**8.40**	**10.44**	**48.33**		**158.4**
	MEDIAN	**8.52**	**10.40**	**48.10**		**---**
	OBSERVATIONS	**10**	**10**	**9**		**13**
5/16/07	Aquila (KS)	---	---	---	---	5.1 (B)
6/5/07	Cascade Natural Gas (OR)	---	10.10	45.00	---	-0.7 (B)
6/13/07	Northern States Power (ND)	8.96	10.75	51.59	12/07-A	2.2 (I,B)
6/29/07	Yankee Gas Services (CT)	8.03	10.10	50.30	6/06-A	22.1 (B)
6/29/07	Public Service Co. of New Mexico (NM)	7.96	9.53	51.80	12/05-YE	8.6
2007	***2ND QUARTER: AVERAGES/TOTAL***	**8.32**	**10.12**	**49.67**		**37.3**
	MEDIAN	**8.03**	**10.10**	**50.95**		**---**
	OBSERVATIONS	**3**	**4**	**4**		**5**
7/3/07	Public Service of Colorado (CO)	8.67	10.25	60.17	6/06-A	32.3 (B)
7/13/07	Arkansas Western Gas (AR)	6.06	9.50	34.29 *	10/06-YE	5.8 (B)
7/19/07	Laclede Gas (MO)	---	---	---	---	38.6 (B)
7/24/07	Aquila (NE)	8.80	10.40	50.73	6/06-YE	9.2 (I)
7/31/07	Atmos Energy (KY)	---	---	---	---	5.5 (B)
8/1/07	Southern Indiana Gas & Electric (IN)	7.20	10.15	47.05 *	3/06-YE	5.1 (B)
8/21/07	Consumers Energy (MI)	---	---	---	---	49.8 (Bp)
8/29/07	Columbia Gas of Kentucky (KY)	---	10.50	---	---	7.3 (B)
9/10/07	Northern States Power-Minnesota (MN)	8.37	9.71	51.98	12/07-A	14.4 (I)
9/19/07	Washington Gas Light (VA)	8.41	10.00	---	12/05	3.9 (B,I)
9/20/07	Pacific Gas and Electric (CA)	---	---	---	---	27.6 (B,Z,20)
9/25/07	Consolidated Edison of New York (NY)	7.63	9.70	48.00	9/08-A	202.5 (B,Z)
2007	***3RD QUARTER: AVERAGES/TOTAL***	**7.88**	**10.03**	**48.70**		**402.0**
	MEDIAN	**8.37**	**10.08**	**49.37**		**---**
	OBSERVATIONS	**7**	**8**	**6**		**12**

GAS UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
10/8/07	Atmos Energy (TN)	8.03	10.48	44.20	10/08-A	4.0 (B)
10/12/07	South Carolina Electric & Gas (SC)	---	---	---	3/07	4.6
10/19/07	Delta Natural Gas (KY)	---	10.50	---	---	3.9 (B)
10/25/07	CenterPoint Energy Resources (AR)	5.73	9.65	33.73 *	12/06-YE	20.0 (B)
11/15/07	Washington Gas Light (MD)	8.20	10.00	53.02	12/06-YE	20.6
11/20/07	Arkansas Oklahoma Gas (AR)	6.45	9.90	41.46 *	2/07-YE	3.3 (B)
11/27/07	UNS Gas (AZ)	8.30	10.00	50.00	12/05-YE	5.3
11/29/07	Cheyenne Light, Fuel & Power (WY)	8.84	10.90	54.00 (Hy)	9/06-YE	4.4 (B)
12/14/07	Madison Gas and Electric (WI)	9.09	10.80	57.36	12/08-A/P	7.8
12/18/07	NorthWestern Energy Div. (NE)	---	10.40	---	12/06	1.5 (B)
12/18/07	NorthWestern Energy Div. (SD)	7.96	---	---	12/06-A	3.1 (B,21)
12/19/07	Avista Corporation (WA)	8.20	10.20	46.00	12/06-A	3.3 (B)
12/21/07	Pacific Gas and Electric (CA)	8.79	11.35	52.00	12/08-A	0.0
12/21/07	San Diego Gas & Electric (CA)	8.40	11.10	49.00	12/08-A	1.4
12/21/07	Brooklyn Union Gas (NY)	---	9.80	---	---	46.9
12/21/07	KeySpan Gas East (NY)	---	9.80	---	---	82.4
12/21/07	National Fuel Gas Distribution (NY)	7.61	9.10	44.35	12/08-A	1.8
12/28/07	Washington Gas Light (DC)	---	---	---	6/06	1.4 (B)
2007	***4TH QUARTER: AVERAGES/TOTAL***	**7.97**	**10.27**	**47.74**		**215.7**
	MEDIAN	**8.20**	**10.20**	**49.00**		**---**
	OBSERVATIONS	**12**	**15**	**11**		**18**
2007	***FULL YEAR: AVERAGES/TOTAL***	**8.12**	**10.24**	**48.37**		**813.4**
	MEDIAN	**8.34**	**10.20**	**49.50**		**---**
	OBSERVATIONS	**32**	**37**	**30**		**48**
1/8/08	Northern States Power-Wisconsin (WI)	9.67	10.75	52.51	12/08-A	5.3
1/17/08	Wisconsin Electric Power (WI)	9.15	10.75	54.36	12/08-A/P	4.0
1/17/08	Wisconsin Gas (WI)	10.91	10.75	46.64	12/08-A/P	20.1
2/5/08	North Shore Gas (IL)	7.96	9.99	56.00	9/06-YE	-0.2
2/5/08	Peoples Gas Light & Coke (IL)	7.76	10.19	56.00	9/06-YE	71.2
2/13/08	Indiana Gas (IN)	7.80	10.20	48.99 *	12/06-YE	26.9 (B)
3/31/08	Avista Corp. (OR)	8.21	10.00	50.00	12/06-A	2.3 (B,Z)
2008	***1ST QUARTER: AVERAGES/TOTAL***	**8.78**	**10.38**	**52.07**		**129.6**
	MEDIAN	**8.21**	**10.20**	**52.51**		**---**
	OBSERVATIONS	**7**	**7**	**7**		**7**
4/23/08	Atmos Energy (KS)	---	---	---	---	2.1 (B)
5/28/08	Duke Energy (OH)	8.45	10.50	55.76	12/07-DC	18.2 (B)
6/24/08	Atmos Energy (TX)	7.98	10.00	48.27	6/07-YE	19.7 (22)
6/27/08	Questar Gas (UT)	8.41	10.00	51.38	12/08-A	12.0 (Bp)

GAS UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
2008	***2ND QUARTER: AVERAGES/TOTAL***	**8.28**	**10.17**	**51.80**		**52.0**
	MEDIAN	**8.41**	**10.00**	**51.38**		**---**
	OBSERVATIONS	**3**	**3**	**3**		**4**
7/1/08	NorthWestern Corporation (MT)	--- (23)	---	---	---	5.0 (B,I)
7/31/08	San Diego Gas & Electric (CA)	--- (15)	--- (15)	--- (15)	12/08-A	33.0 (B,Z)
7/31/08	Southern California Gas (CA)	--- (24)	--- (24)	--- (24)	12/08-A	214.0 (B,Z)
8/27/08	SourceGas Distribution (CO)	8.26	10.25	53.13	8/07-A	14.9 (B)
9/2/08	Chesapeake Utilities (DE)	8.91	10.25	61.81	3/07	0.3 (I,B)
9/17/08	Atmos Energy (GA)	7.75	10.70	45.00	3/09-A	3.4
9/24/08	Central Illinois Light (IL)	8.03	10.68	46.50	12/06-YE	-9.2
9/24/08	Central Illinois Public Service (IL)	8.22	10.68	47.91	12/06-YE	7.7
9/24/08	Illinois Power (IL)	8.70	10.68	51.76	12/06-YE	39.8
9/30/08	Avista Corp. (ID)	8.45	10.20	47.94	12/07-A	3.9 (B)
2008	***3RD QUARTER: AVERAGES/TOTAL***	**8.33**	**10.49**	**50.58**		**312.8**
	MEDIAN	**8.26**	**10.68**	**47.94**		**---**
	OBSERVATIONS	**7**	**7**	**7**		**10**
10/3/08	New Jersey Natural Gas (NJ)	7.76	10.30	51.20	4/08-YE	32.5 (B)
10/8/08	Puget Sound Energy (WA)	8.25	10.15	46.00	9/07-A	49.2 (B)
10/14/08	South Carolina Electric & Gas (SC)	---	---	---	3/08	3.7 (M)
10/15/08	East Ohio Gas (OH)	8.49 (R)	---	---	12/07-DC	40.5 (B,R)
10/20/08	CenterPoint Energy Resources (TX)	8.80	10.06	55.40	12/07-YE	1.2
10/23/08	Columbia Gas of Pennsylvania (PA)	---	---	---	9/07	41.5 (B)
10/23/08	PECO Energy (PA)	---	---	---	12/07	76.5 (B)
10/24/08	Piedmont Natural Gas (NC)	8.55	10.60	51.00	12/07-YE	15.7 (B)
10/24/08	Public Service of North Carolina (NC)	8.54	10.60	54.00	12/07-YE	9.1 (B,25)
11/24/08	Southwest Gas-So. California Div. (CA)	7.87	10.50	47.00	12/09-A	2.4 (B,26)
11/24/08	Southwest Gas-No. California Div. (CA)	8.99	10.50	47.00	12/09-A	-1.0 (B,26)
11/24/08	Southwest Gas-So. Lk. Tahoe Dist. (CA)	8.99	10.50	47.00	12/09-A	1.8 (B,26)
11/24/08	Narragansett Electric (RI)	---	10.50	47.71 (Hy)	9/07-A	13.7
12/3/08	Columbia Gas of Ohio (OH)	8.12	10.39	---	9/08-DC	47.1 (B)
12/23/08	Consumers Energy (MI)	---	---	---	---	22.4 (B)
12/24/08	Southwest Gas (AZ)	8.86 (E)	10.00	43.44	4/07-YE	33.5
12/26/08	Northwest Natural Gas (WA)	8.40	10.10	50.74	9/07-A	2.7 (B)
12/29/08	Avista Corporation (WA)	8.22	10.20	46.30	12/07-A	4.8 (B)
12/30/08	Wisconsin Power and Light (WI)	---	---	---	12/09	-3.9 (B)
12/30/08	Wisconsin Public Service (WI)	---	---	53.41	12/09	-3.0 (B)
2008	***4TH QUARTER: AVERAGES/TOTAL***	**8.45**	**10.34**	**49.25**		**390.4**
	MEDIAN	**8.49**	**10.39**	**47.71**		**---**
	OBSERVATIONS	**13**	**13**	**13**		**20**
2008	***YEAR-TO-DATE: AVERAGES/TOTAL***	**8.48**	**10.37**	**50.47**		**884.8**
	MEDIAN	**8.41**	**10.35**	**50.37**		**---**
	OBSERVATIONS	**30**	**30**	**30**		**41**

FOOTNOTES

A- Average
B- Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
Bp- Order followed partial stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
D- Applies to electric delivery only
DC- Date certain
E- Estimated
Hy- Hypothetical capital struture utilized.
I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
M- "Make-whole" increase based on return on equity or overall return of previous case
P- Partial inclusion of CWIP in rate base without AFUDC offset to income
R- Revised
Tr- Applies to electric transmission only
YE- Year-end
Z- Rate change implemented in multiple steps.
* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Rate increase effective retroactive to 1/1/07.
(2) Rate increase effective retroactive to 6/16/07.
(3) Represents initial revenue requirement for the newly established conpmany.
(4) Rate increase results from a limited issue reopening of a case initially decided on 1/19/07.
(5) Rate increase effective 2/20/08.
(6) ROE applies only to a proposed 200-MW wind generation facility, and is applicable over the 25-year depreciable life of the project.
(7) Rate increase effective 5/1/08.
(8) ROE applies only to a proposed 585-MW coal generation facility, is applicable for AFUDC and CWIP purposes and over the first 12 years of the plant's commercial operation, and includes a 100-basis-point incentive premium.
(9) The 8.1% ROR utilized in the company's case decided on 2/28/08, was incorporated into this proceeding.
(10) ROE applies only to a proposed 108-MW wind generation facility, and is applicable over the 20-year depreciable life of the project.
(11) Commission also authorized a 150-basis-point ROE premium for the new, 514-MW, combined-cycle Tracy generating plant, and a 500-basis-point premium for demand-side management investments.
(12) Case abated by Commission at company request.
(13) Rate reduction ordered in conjunction with the authorization of a new five-year alternative regulation plan.
(14) Order noted that an ROR of 7.04% is implied in the approved settement.
(15) Rate of return was not an issue in this proceeding. The authorized rate change incorporated the 10.7% return on equity (49% of capital) and the 8.23% return on rate base previously authorized the company for 2007.
(16) ROE applies only to a proposed 52.5-MW wind generation facility over the 20-year depreciable life of the project.
(17) Return and capital structure parameters apply only to the company's 30% interest in the 740-MW coal-fired Colstrip Unit 4 generating plant.
(18) Represents base rate increase. The company's overall electric rates were unchanged as the base rate increase represents the transfer to base rates of a $48 million fuel surcharge that was authorized on 7/3/08.
(19) Parent company capital structure utilized.
(20) Rate increases applicable to gas transmission and storage operations. Initial increase to be effective 1/1/08.
(21) Rate increase effective retroactive to 12/1/07.
(22) Parameters shown apply to parties for whom the case was fully litigated. A settlement executed with the majority of the cities served by Atmos specified a total company $10 million rate hike based on a 9.6% ROE (48% of capital) and a 7.79% ROR. The revenue requirement increase applicable to the settlement's signatories is $8.2 million, while that applicable to non-signatories subject to the Commission order is $3.5 million. The aggregate impact of the two rate adjustments is an $11.7 million increase.
(23) Order noted that an ROR of 7.59% is implied in the approved settement.
(24) Rate of return was not an issue in this proceeding. The rate change incorpated the 10.82% return on equity (48% of capital) and 8.68% return on rate base authorized the company in its automatic cost of capital adjustment mechanism.
(25) Indicated rate hike represents distribution or margin rate increase. Because fixed gas costs were reduced by $8.4 million, the net, overall rate increase was $0.7 million.
(26) Additional increases authorized for each year 2010 through 2013.

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
SEP 30 2005
DOCKETED BY CAR

EXHIBIT S-2 ADMITTED

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF CHAPARRAL CITY WATER COMPANY, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS ~~RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.~~

DOCKET NO. W-02113A-04-0616

DECISION NO. 68176

OPINION AND ORDER

DATE OF PRE-HEARING CONFERENCE: May 26, 2005

DATE OF HEARING: May 31, June 1, June 6 and June 8, 2005

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Teena Wolfe

IN ATTENDANCE: Kristen K. Mayes, Commissioner

APPEARANCES: Norman D. James and Jay L. Shapiro, FENNEMORE CRAIG, on behalf of Chaparral City Water Company;

Daniel Pozefsky, on behalf of the Residential Utility Consumer Office; and

David Ronald, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

I. INTRODUCTION

A. Procedural History

On August 24, 2004, Chaparral City Water Company ("Chaparral City" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for a determination of the current fair value of its utility plant and property and for increases in its rates and charges for utility

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service based thereon.

On September 14, 2004, the Residential Utility Consumer Office ("RUCO") filed an Application to Intervene, which was granted.

On September 23, 2004, the Commission's Utilities Division Staff ("Staff") filed a letter stating that the Company's application met the sufficiency requirements set forth in A.A.C. R14-2-103, and classifying the Company as a Class A utility.

On September 28, 2005, a Rate Case Procedural Order was issued setting a hearing date and setting procedural deadlines for public notice, intervention, discovery, and for prefiling direct, rebuttal, surrebuttal and rejoinder testimony.

On February 15, 2005, the Company filed a Notice of Publication certifying that public notice was published in *The Fountain Hills Times* on January 26, 2005. Public notice of the application and hearing was also mailed to each of the Company's customers in their January 2005 bills. Written public comments in opposition to the rate increase were received as set forth herein. Aside from RUCO, no other party requested intervention.

A hearing was held as scheduled before a duly authorized Administrative Law Judge of the Commission, commencing on May 31, 2005 and continuing on June 1, June 6 and June 8, 2005. Public comment was taken at the commencement of the hearing. The Company, RUCO, and Staff appeared and presented evidence at the hearing. Following the filing of closing briefs on July 6, 2005, and reply briefs on July 20, 2005, the matter was taken under advisement pending the submission of a Recommended Opinion and Order to the Commission. On July 28, 2005, the Company filed a Request for Official Notice of Rate Increases Requested by Arizona Public Service Company and Salt River Project.

B. Rate Application

Chaparral City is an Arizona corporation wholly owned by American States Water Company

("American States"), which is publicly traded on the New York Stock Exchange. American States' primary operating subsidiary is Southern California Water Company. In October 2000, as approved by this Commission in Decision No. 62909 (September 18, 2000), American States purchased Chaparral City's stock from MCO Properties, Inc. ("MCO"), the real estate developer that owned and operated the Company. Chaparral City provides water utility service to approximately 12,000 customers located in the northeastern portion of the Phoenix metropolitan area, including the Town of Fountain Hills and a small portion of the City of Scottsdale. The majority of the Company's approximately 11,340 residential customers during the test year were served by ¾-inch meters, but approximately 3,000 residential customers have larger meters. During the test year, the Company also provided service to over 300 commercial customers and over 400 irrigation customers.

The application is based on a test year ended December 31, 2003. The Company is requesting an increase in revenues of $1,773,091, or 28.59 percent, for a total revenue requirement of $7,795,935. This revenue requirement is lower than that requested in the application due to the Company's adoption of a number of adjustments recommended by Staff and RUCO, and other adjustments the Company made. RUCO is recommending an increase in revenues of $603,988, or 9.74 percent, for a total revenue requirement of $6,803,753. Staff is recommending a revenue increase of $809,692, or 13.05 percent, for a total revenue requirement of $7,012,536. Based on adjustments to the Company's filing as set forth herein, we authorize an increase in revenues of $1,107,620, an increase of 17.86 percent, for a total revenue requirement of $7,310,464.

II. RATE BASE

A. Plant in Service

The Company is proposing a total of $42,538,338 for plant in service relating to its Original Cost Rate Base ("OCRB") (Bourassa Rj. Sched. B-1). Of that amount, $ 2,979,239 represents plant additions placed in service after the test year: $2,038,443 for the expansion of its Shea Water

Treatment Plant ("Shea WTP"), and $940,979 related to the Fountain Hills Boulevard transmission main (Bourassa Rb. Sched. B-2).

1. Shea Water Treatment Plant Expansion

The Company is requesting rate base treatment of $2,038,442 for the Shea WTP expansion. The expansion was begun in 2003 and brought on line in March 2004. The Company has two facilities that are used to treat its CAP water allocation. The Company's original treatment facility is a package plant with a current treatment capacity of about 3 million gallons per day ("gpd"). The Shea WTP consists of three separate treatment modules, each module having a treatment capacity of 5 million gpd. The first module was brought on line in 1996, and the expansion includes the final two treatment modules. The Company had planned to bring these modules on line before the end of the 2003 test year but was delayed in obtaining final regulatory approvals. The Company argues on brief that prior to its acquisition of the Chaparral City system, the prior owner had ignored growth and that as a result, the Company lacked sufficient operational flexibility in its water treatment facilities to perform routine repairs and maintenance or address emergencies. From the years 1995 through 2001, no additional treatment capacity was constructed, despite the fact that the Company added over 4,400 customers, for an average growth rate of ten percent per year (Hanford Rj. at 2, citing Scott Dt., Exhibit MSJ at 13). During the test year, the Company's peak demand exceeded 10 million gpd but it could treat only 8 million gpd of CAP water (Tr. at 63).

RUCO does not oppose the inclusion of the Shea WTP in rate base. According to RUCO's witness, the full Shea WTP capacity was required for water provisioning to the test year customer base, and the Company's construction costs were known and measurable, and paid, during the test year (Moore Dt. at 12). RUCO is recommending that the total actual cost of $2,038,443 be allowed in rate base as post-test year plant (*Id.*).

Staff disagrees with the Company and RUCO, arguing that the Shea WTP is not revenue

neutral as it was not needed during the test year (Moe Dt. at 10), and is recommending its exclusion from test year plant in service. Staff asserts that because the Shea WTP expansion increases treatment capacity, increased revenues from water sales are possible, and that no corresponding increase in test year revenues was made to account for this possibility; that the Company was able to meet peak demand in the test year using groundwater as a supplement to its CAP allocation; and that the Company will benefit more than the ratepayers from the additional protection against outages that the increased treatment capacity will provide. However, it appears that if the expansion had been placed in service during the test year, just three months earlier, Staff would have allowed it in rate base (*see* Bourassa Rj. at Exhibit TJB-2, Staff Data Response 3-17).

As Staff argued on brief in support of its recommendation to include the post-test year Fountain Hills Boulevard transmission main in rate base, inclusion of post-test year plant always causes some mismatch between revenues and expenses, even if post-test year plant is revenue neutral, used and useful, and the value of the additions is known (*see* Staff Cl. Br. at 2-3). Therefore, even though quantification of the inevitable mismatch may not be possible, the significance of the mismatch requires careful consideration (*see id.*). Given that ninety percent of the Company's water supply comes from CAP water, which must be treated before it can be delivered to customers for potable purposes, the ability of the Company to reliably treat its test year CAP water supply is an important factor that weighs heavily in our consideration of whether to include the Shea WTP expansion in rate base. We find that the weight of the evidence in this proceeding supports the Company's assertion that the Shea WTP expansion, which the Company paid for during the test year, and has been used and useful since March of 2004, allows the Company to reliably meet test year peak demands during the summer months with CAP water, which is a renewable resource we wish to encourage, while retaining the ability to take individual modules off line for repairs and to meet emergency needs. We find credible the Company's assertion that prior to the Shea WTP expansion,

the Company had been operating with minimal flexibility for routine maintenance and repairs and had no operating safety margin in the event of a need to shut down some of its treatment facilities. These factors support, in this particular case, treating the Shea WTP expansion, which was paid for during the test year and placed in service within three months following the test year, as if it were actually in service at the end of the test year. We will therefore adopt RUCO's recommendation that the total actual cost of $2,038,443 associated with the Shea WTP be allowed in rate base.

2. Fountain Hills Boulevard Main

The Company also requests inclusion of $940,797 in rate base for the Company's share of the cost of installing the Fountain Hills Boulevard main. The Fountain Hills Boulevard main is a 16-inch water transmission main approximately two miles in length, that was placed in service in November 2004. Because a portion of this main was constructed in connection with new development, part of its cost was paid by the developer.

RUCO objects to including the full amount of the Company's cost associated with the main in rate base. RUCO claims that installation of the main results in operating expense savings due to reduced pumping costs, and that the Company's request does not account for the purported savings (RUCO Cl. Br. at 5-6). RUCO did not calculate the savings it alleges, arguing that the burden is on the Company to establish the plant value, taking into account both the cost and the savings (*Id.*, fn 4).

Staff recommends that the Fountain Hills Boulevard main be included in rate base. Staff states that the main addition provides operational flexibility and improved service to customers (Scott Dt., Exhibit MSJ at 7); that it will assist in providing CAP water flow to blend with the Company's Well Number 10 groundwater source in order to reduce the arsenic concentration in water from that well (*Id.*); and that any revenues that would potentially come from the transmission line would be incidental (Moe Dt. at 10). Staff's engineering witness testified that there are no pumping cost savings associated with the new main, because its installation does not result in changes in the way

the system is operated (Tr. at 635-638).

The Fountain Hills Boulevard transmission main has been used and useful since November 2004, providing operational flexibility and improved service to customers. The weight of the evidence does not demonstrate a reduction in operating costs attributable to its operation that would necessitate a reduction in its cost. Based on the evidence presented, we find that the Company's cost associated with the Fountain Hills Boulevard transmission main, $940,797, should be included in rate base.

3. CAP Hook-Up Fees

In the Company's last rate case, Decision No. 57395 (May 23, 1991), the Commission ordered that a portion of the revenue requirement determined in that case be recovered by means of hook-up fees from new customers due to the unique circumstance that the required revenue increase was due primarily to CAP facilities coming on line (*see* pages 4-5 of Decision No. 57395). In its current application, the Company proposes that the entirety of its revenue requirement be recovered in accordance with traditional rate making principles, through customers' rates. Chaparral City made an accounting adjustment to remove $220,000 in test year hook-up fees from test year revenues (Kozoman Dt. Sched. H-1). All the parties to this case are in agreement that the hook-up fees should no longer be treated as revenues.

RUCO proposes that an adjustment also be made to increase test year contributions-in-aid of construction ("CIAC") by $220,000, the amount of test year hook-up fees, which would reduce the Company's rate base by $220,000. RUCO argues that this adjustment is necessary in order to recognize that hook-up fees financed $220,000 of plant during the test year. The Company objects to this adjustment, because it does not include a corresponding $220,000 adjustment to the asset side of the balance sheet.

RUCO's proposal assumes that the $220,000 collected during the test year as hook-up fees

was used to pay for plant additions. In most circumstances, such an assumption would be correct, because this Commission normally limits the use of hook-up fees to the installation of utility plant. However, as described by the Company's witness (Tr. at 829-832), Decision No. 57395 did not limit the use of the authorized "hook-up fees" to plant investment, but clearly intended that the "hook-up fees" be treated as operating revenues (Decision No. 57395 at 5-6). The $220,000 represents test year revenue and not plant additions. RUCO's proposed adjustment is therefore unnecessary and will not be adopted.

The Company does not have an approved hook-up fee tariff on file at this time. We will require the Company to file a hook-up fee tariff, and to obtain Commission approval of the tariff prior to collecting any hook-up fees on a going-forward basis.

4. Reclassification of Expenses to Plant in Service

RUCO recommends the removal of $5,686 of repairs and maintenance expense associated with water treatment plant. The Company proposes that the expense be reclassified as water treatment plant and Staff agrees. This proposal is reasonable and will be adopted.

Staff recommends that $26,850 from outside services expense be reclassified to meters and pumping equipment. The Company agrees with this recommendation, which is reasonable and will be adopted.

B. Accumulated Depreciation

The Company proposes an adjustment to decrease accumulated depreciation by $11,421, in order to correct for an error in the Company's filing (Co. Rb. Sched. B-2 at 3). Staff proposed additional adjustments to accumulated depreciation associated with the reclassification of expenses to plant in service discussed above, and with the removal of vehicles from plant in service as agreed to by the Company. These adjustments are reasonable and will be adopted, for total accumulated depreciation of $11,980,749.

III. ORIGINAL COST RATE BASE

With the adjustments discussed above, test year plant in service is $42,539,165, and deducting accumulated depreciation results in net plant in service of $30,558,416. As proposed by the Company, test year net CIAC is $258,143, advances in aid of construction ("AIAC") is $10,327,171, customer deposits are $1,070,331, and deferred income tax credits are $1,872,006. Deducting these items from net plant in service results in an adjusted original cost rate base ("OCRB") for ratemaking purposes of $17,030,765.

IV. RECONSTRUCTION COST NEW RATE BASE

Chaparral City submitted schedules reflecting both an OCRB and an estimated reconstruction cost new less depreciation ("RCND") rate base. Staff reviewed the Company's RCN study and agreed with the Company's plant in service values (Scott Dt., Exhibit MSJ at 6). The adjustments discussed above and reflected in our determination of OCRB are equally applicable to the Company's proposed RCND. Based on the foregoing discussion, we therefore adopt an adjusted RCND for ratemaking purposes of $23,649,830.

V. FAIR VALUE RATE BASE

Chaparral City is proposing a FVRB based on the average of its OCRB and RCND. Staff also utilized this approach. RUCO recommends a FVRB equal to its OCRB. We find that the average of the adjusted OCRB and RCND provides a reasonable measurement of the current value of the Company's property dedicated to public service. Based upon a 50/50 weighting of the OCRB and RCND, we find Chaparral City's FVRB at December 31, 2003 to be $20,340,298. The rate of return to be applied to FVRB is discussed in Section VIII below.

VI. OPERATING INCOME

A. Expenses

Several adjustments to operating expenses that Staff and RUCO proposed were either agreed

to by the Company prior to the hearing or were not addressed on brief by the Company.[1] We find those proposed adjustments to be reasonable and they will be adopted. Remaining contested operating expense issues are addressed below.

1. Expense Normalization

Staff proposes normalization adjustments in several accounts in which Staff believes test year expenses were not representative of a normal year. The expense accounts to which Staff proposes normalization adjustments are office expenses, outside services, transportation expenses, and miscellaneous expenses. Staff asserts that while operating expenses normally remain fairly stable from year to year, a ratio analysis reveals that the test year expenses in these accounts show a dramatic change from prior years and are not reflective of normal expense levels (Tr. at 731; Moe Sb. at 6). Due to the significant fluctuation in expenses in these accounts, Staff recommends that the actual 2003 test year expense amounts in these accounts be normalized by averaging them with the actual expense amounts incurred in the years 2001 and 2002, in order to mitigate any extenuating circumstances leading to the test year expense levels (Moe Dt. at 14-18; Tr. at 815-16).

Chaparral City advocates for the use of actual test year expenses. The Company claims that Staff's normalization adjustment is not based on known and measurable changes in expenses, and asserts that the averages will produce unrealistic results on a going forward basis (Bourassa Rb. at 33). The Company asserts that 2001 and 2002 expense levels do not reflect current operating expense levels because it took until 2003 for the Company to get its operations up to the current level of system reliability after acquiring the system from MCO in late 2000 (Hanford Rj. at 7-8).

Test year expenses are used to estimate the level of expense that a Company will experience during the period that rates will be in effect. Normalization of expenses is an appropriate ratemaking tool that insures that unusual levels of expense in a test year do not skew expense recovery, and is

[1]The parties were informed that issues not briefed would be assumed waived. *See* Transcript of Pre-hearing Conference at 11.

used not only in cases where test year expenses are abnormally high, but also in cases where test year expenses are abnormally low. In this case, the evidence presented shows test year expenses in these four accounts to be abnormally high. The 2001 and 2002 expense levels in these accounts are known and measurable. Averaging these known and measurable amounts with the unusually high 2003 test year levels recognize the "across the board increase in expenses" the Company claims has occurred, while producing a realistic estimate of reasonable expenses in these accounts on a going-forward basis. Chaparral City argues that use of year 2004 expenses would have illustrated whether the 2003 expense levels were unusual, or reflect operating expense levels on a going forward basis (Co. Br. at 19). However, because the Company did not provide a comparison of 2004 expenses to test year expenses (Tr. at 732), its argument is speculative. Based on the record evidence, we find it appropriate to normalize the test year level of expenses in these four accounts. Staff's recommendation is reasonable and will be adopted.

2. Legal Expense Related to Purchase from MCO

RUCO recommends that the legal expenses associated with the purchase of the Company from MCO be disallowed from test year outside services expenses because they were unique and not a typical or recurring expense. Chaparral City concedes that the same legal matters resulting in expense during the test year may not reoccur, but that the test year reflects a level of annual legal expenses that a utility of the Company's size is likely to incur in the future (Bourassa Rb. at 35-36; Bourassa Rj. at 22). The legal expenses in question are included in outside services expense, which will be normalized, as discussed above. We find that the normalization of test year outside services expense addresses this issue appropriately and that no further adjustment is necessary.

3. Tank Inspection and Cleaning Expense

The Company proposes to remove operating expenses of $35,400 incurred during the test year for tank inspection and cleaning, and to instead amortize and recover those costs over five years at

approximately $7,080 per year (Bourassa Rb. at 31; Rb. Scheds. B-2 at 5 and C-2 at 8). The Company's witness testified that the inspection and cleaning may not be an annual recurring expense, but that it is a prudent and necessary expense incurred in the provision of water services (Bourassa Rb. at 31). RUCO recommends that these costs be disallowed, because they were already recovered through 2003 operating expenses, and the next inspection has not been scheduled (Moore Sb. at 16-17). Staff asserts that its expense normalization adjustment addresses this issue, and recommends that the Company's proposed adjustment not be adopted. We concur with Staff that its normalization adjustment to outside services expense appropriately addresses the issue. Both the disallowance proposed by RUCO and the Company's proposal to amortize this particular expense are therefore unnecessary.

4. Wages and Salaries Expense

The Company, Staff and RUCO proposed that a portion of the Company's wages and salaries expense be capitalized. The capitalization rate for 2003 was 17.46 percent and the 2004 capitalization rate was 17.31 percent (Bourassa Rb. at 30). The Company and Staff both propose the use of the 2004 capitalization rates, which are known and are the most current rates (*Id.*, Bourassa Rj. at 19; Moe Sb. at 14), which results in proposed wages and salaries expense of $991,217. In arriving at its lower recommended wages and salaries expense of $877,231, RUCO uses the capitalization rate that the Company originally provided to it, and does not accept the corrected capitalization rate the Company later provided. (Moore Sb. at 13). The Company asserts that it originally erroneously provided RUCO the Company's payroll system coded default percentages, and not its actual capitalization rate (Bourassa Rb. at 30, Rj. at 19). We agree with the Company and Staff's use of the 2004 capitalization rate of 17.31 percent, as it reflects known and most current rates, and will adopt their recommended wages and salaries expense of $991,217.

5. Purchased Power Expense

The Company proposes that purchased power expense should be adjusted to take into account recent rate increases of Salt River Project ("SRP") and Arizona Public Service Company ("APS") (Bourassa Rj. at 17). Staff agrees with this adjustment (Moe Sb. at 16). RUCO opposes this adjustment claiming that the increases in power rates are too far outside the test year (Moore Sb. at 11). The SRP and APS rate increases are known and measurable expenses. The adjustment proposed by the Company and Staff is appropriate and will be adopted, for total purchased power expense of $510,947.

6. Property Tax Expense

The Arizona Department of Revenue ("ADOR") determines the value of utility property for tax purposes using a formula that is based on the utility's historical revenues. The Company and Staff propose to follow recent Commission Decisions[2] to use adjusted test-year revenues in the application of the ADOR formula in order to determine allowed property tax expense (Bourassa Rj. at 16; Moe Dt. at 19). RUCO continues to disagree with the Commission's use of adjusted test year revenues in the application of the ADOR formula for estimating property tax expense for ratemaking purposes, and argues that only historical revenues should be used.

In an attempt to support its argument, RUCO compared the results of its methodology, using the Company's historical revenues for the years 2001, 2002 and 2003, with the results of the Commission's methodology, using the Company's historical revenues and adjusted test year revenues, in order to predict the property taxes assessed by ADOR in 2004 (*see* Hearing Exhibit R-2), and asserts that because its methodology more accurately predicted the actual 2004 tax assessment,

[2] *E.g., Rio Rico Utilities,* Decision No. 67279 (October 5, 2004) (finding that use of only historic revenues understates the expense level); *Arizona Water Company,* Decision No. 64282 (December 28, 2001) (accepting Arizona Water Company's property tax calculation, which included proposed revenues); *Bella Vista Water Company,* Decision No. 65350 (November 1, 2002) (concluding that "the most logical approach is to use the two most recent historic years' revenues, and the projected revenues under the newly approved rates"); *Arizona American Water Company,* Decision No. 67093 (June 30, 2004).

that the Commission should adopt its approach (RUCO Br. at 8-9). We do not agree. Exhibit R-2 does not, and cannot, include a comparison of results of RUCO's backward-looking methodology with results of the Commission's approach for any years beyond 2004, because the actual assessments for the years following 2004 are unknown. What is known is that any revenue increase approved in this proceeding will increase the Company's property taxes, barring the occurrence of very extraordinary circumstances. ADOR will never again use the inputs of revenues for the years 2001, 2002 and 2003, the years RUCO advocates using in this proceeding, to determine property tax levels for Chaparral City. RUCO's calculation methodology, which uses only historical revenues, unfairly and unreasonably understates property tax expense, and is therefore inappropriate for ratemaking purposes.

As we have repeatedly found, the input of known revenue increases is necessary in order to fairly estimate property tax expense for ratemaking purposes. RUCO has not demonstrated in this proceeding a basis for departure from our prior determinations on this issue.[3] We will therefore adopt the recommendations of the Company and Staff to follow recent Commission Decisions to use adjusted test year revenues in determining property tax expense.

The legislature recently enacted Arizona House Bill 2779, which will gradually lower the assessment ratio for Class 1 properties, such as utility property, from 25 percent to 20 percent over a ten year period, by means of a reduction in the assessment ratio of ½ percent a year. Assessment ratios are applied to full cash value to derive an assessed value on which property tax is applied (Tr. at 643). Although the new assessment ratios are known, their actual effect on the amount of property taxes assessed in the future is unknown, because unlike the assessment ratios which are set by the legislature, actual property tax rates are set by counties and other governmental entities (Tr. at 643, 645). As requested, the parties introduced schedules at the hearing that estimate the impact of HB

[3] RUCO has not appealed prior Commission Decisions rejecting its proposed methodology.

2779 on the Company's property tax expense level (*see* Hearing Exhibits A-26, R-8, S-15). The schedules show that even if property tax rates were to remain constant, the effect of calculating HB 2779's lower assessment ratios into property tax estimates would have a de minimus effect on rates in this case (*see* Tr. at 596; 644). No party recommended that its property tax calculation be amended.

Based on the revenue requirement we adopt herein, and utilizing the methodology adopted by the Commission in our prior Decisions for the reasons set forth herein, an allowance will be made for property tax expense in the amount of $299,495.

7. Depreciation Expense

The Company's application showed test year depreciation expense of $920,648. The Company did not perform a depreciation study, but chose instead to base its depreciation rates on Staff's developed typical and customary depreciation rates (Bourassa Rb at 2, Rj. at 17). Based on its proposed plant in service amounts, the Company proposed test year adjusted depreciation expense of $1,432,828 (Bourassa Rj. Sched. C-1, p. 1). Staff accepted the Company's use of Staff's developed typical and customary depreciation rates to calculate its proposed test year adjusted depreciation expense of $1,365,295, based on its proposed plant in service (Moe Sb. Sched. JRM-24). RUCO disagrees with the use of Staff's developed typical and customary depreciation rates and proposes the use of a different set of depreciation rates instead, as discussed in Section XI hereinbelow. Using its proposed depreciation rates, RUCO proposed test year adjusted depreciation expense of $1,113,339, based on its proposed plant in service amounts (Moore Dt. Sched. RLM-10, p. 1 of 2). Applying RUCO's proposed depreciation rates to the plant in service amounts approved herein would result in test year adjusted depreciation expense of approximately $1,139,194. Consistent with our discussion of appropriate depreciation rates in Section XI hereinbelow, we adopt test year adjusted depreciation expense of $1,432,828, based on the plant in service amounts authorized herein and using the depreciation rates proposed by the Company and Staff.

B. Statement of Operating Income

The Company's adjusted test year operating revenues, as agreed by the parties, were $6,202,844. In accordance with the discussion above, the Company's adjusted test year operating expenses for ratemaking purposes total $5,588,597, for an adjusted test year operating income of $614,247.

VII. COST OF CAPITAL

Chaparral City, Staff and RUCO presented cost of capital analyses for purposes of determining a fair value rate of return in this proceeding. The cost of equity proposed by Chaparral City's witness, Dr. Thomas Zepp, translates to a recommended overall weighted average cost of capital of 8.2 percent if its requested automatic adjustment mechanisms for purchased water and purchased power costs are approved, and 8.6 percent if they are not approved. Staff is recommending, based on the analysis of Staff witness Alejandro Ramirez, a weighted average cost of capital of 7.6 percent. Based on the analysis of its witness William Rigsby, RUCO believes the Commission should adopt RUCO's recommended 7.66 percent weighted average cost of capital.

A. Capital Structure and Cost of Debt

1. Capital Structure

The parties are in agreement that the Company's capital structure as of December 31, 2003 should be used to determine the Company's weighted cost of capital, as follows:

Long Term Debt	$ 8,363,309	41.27%
Common Equity	11,901,727	58.73%
Total Capital	$ 20,265,036	100.00%

2. Cost of Debt

The parties also agree that the Company's cost of long term debt is 5.1 percent, which results in a weighted cost of debt of 2.11 percent.

B. Cost of Equity

Although the cost of debt can be determined from fixed cost rates, the cost assigned to the equity component of the capital structure can only be estimated. The cost of equity recommendations advocated by the parties are: Chaparral City, 10.4 percent if its requested automatic adjustment mechanisms for purchased water and purchased power costs are approved, and 11.0 percent if they are not approved; RUCO, 9.45 percent; and Staff, 9.3 percent.

1. Chaparral City

Chaparral City's witness, Dr. Zepp, prepared estimates of the cost of equity based on the discounted cash flow ("DCF") model used by the Federal Energy Regulatory Commission ("FERC") and the risk premium method used by the staff of the California Public Utility Commission ("CPUC staff"). The DCF method of estimating the cost of capital is based on the theory that the present value of a stock is equal to the present value of all expected future dividends or cash flows. The constant growth DCF model assumes that a company will grow at the same rate indefinitely, while the non-constant growth DCF model does not assume that dividends grow at a constant rate over time. The constant-growth DCF formula includes three variables used to estimate the cost of equity: 1) the expected annual dividend; 2) the current stock price; and 3) the expected infinite annual growth rate of dividends ("dividend growth rate"). The constant-growth DCF model calculates a dividend yield by dividing the expected annual dividend by the current stock price, and then adds the resulting dividend yield to the expected infinite annual growth rate of dividends. The Company prefers FERC's constant growth DCF method to the constant growth DCF method used by Commission Staff, because the FERC's method eliminates from consideration any individual utility equity cost estimate that is not at least forty basis points above the cost of investment grade bonds (Zepp Dt. at 24, 30). The Company argues that Staff's constant growth methodology, which does not reject such estimates, lowers Staff's average growth inputs for the model and its resulting equity cost estimate

(Zepp Rj. at 10-13). The Company also advocates use of the risk premium method used by the CPUC staff to estimate the cost of equity instead of the capital asset pricing model ("CAPM") used by Commission Staff, because the CPUC staff's risk premium approach estimates the risk premium by comparing authorized and actual returns on equity ("ROE") with the current yield of investment grade bonds or other debt instruments (Zepp Dt. at 4-5 and 33-34). Using these methods, Dr. Zepp presented updated equity cost estimates in his rejoinder testimony that range from 10.4 percent to 10.9 percent based on the six publicly-traded water utilities included in the sample group.[4] Using the CPUC staff's risk premium approach and interest forecasts, rather than current interest rates, the Company estimated the cost of equity for the water utility sample at 10.5 percent to 10.7 percent (Zepp Rj. at 7-8 and Rejoinder Table 6). Dr. Zepp's analysis included a study of authorized ROEs for the sample group of water utilities, which range from 9.7 percent to 12.7 percent, for an average 10.4 percent, and looked at the returns on equity actually being earned by those water utilities, which averaged 10.0 percent. Dr. Zepp also cited *Value Line*, a source of financial data to which all the parties referred in their analyses, for *Value Line's* projections of returns on common equity of 11.0 percent, 11.5 percent and 12.0 percent for 2005, 2006 and 2008-2010, respectively, for the water utility industry. Dr. Zepp claims that these measures of the cost of equity indicate an equity cost of greater than 10.0 percent for the sample utilities and, he asserts, a higher equity return for Chaparral City, based on his belief that the Company is more risky.

The Company is critical of Staff's implementation of the DCF model, because instead of relying solely on forward-looking estimates of growth, Staff gives a 50 percent weight to historic growth data from 1994-2003, which results in a lower dividend growth rate and a lower equity cost

[4] The Company and Staff used the same six publicly-traded water utilities as proxies in their analyses: American States Water (Chaparral City's parent), Aqua America, California Water Service, Connecticut Water Services, Middlesex Water Company and SJW Corp. RUCO used the three largest publicly-traded water utilities in this group in its analysis: American States Water, Aqua America and California Water Service. These companies represent the water utilities that are currently analyzed by the *The Value Line Investment Survey Small and Mid Cap Edition* and *The Value Line Investment Survey ("Value Line").*

estimate. The Company also argues that Staff's historic dividend growth rates are extremely low, and produce results that are in some cases below the cost of an investment grade bond (*see* Hearing Exhibit A-23), and that Staff's application of the average dividend yield to compute its equity cost "masks" this fact. Dr. Zepp advocates the use of future, rather than historic growth rates, based on his belief that forecasts already incorporate the historic information used by Staff (Zepp Dt. at 25). The Company believes that giving 50 percent weight to historic growth rates double counts what has happened in the past, and that investors are more interested in a stock's future performance than its past performance. The Company states that it therefore prefers the forward-looking approach used by the FERC (Co. Br. at 36). In rejoinder testimony, Dr. Zepp restated Staff witness Ramirez' constant growth DCF model estimate, using the average dividend yield (3.3 percent) and an average of Mr. Ramirez' projected growth rates (7.5 percent), and reached a result of 10.8 percent which is virtually identical to Dr. Zepp's updated estimate using the FERC one-step method, 10.9 percent (Zepp Rj. at 10). Dr. Zepp also restated Staff's multi-stage DCF estimate using Staff's data but also including Staff's 8.7 percent estimate of intrinsic growth which Staff used in a different model and also used a different terminal, second stage growth rate. The results of Dr. Zepp's restatement is a cost of equity estimate of 10.1 percent (Zepp Rj. at 14). The Company states that the multi-stage DCF model that Staff uses is similar to the two-step DCF model FERC uses, but is critical of the choices Staff made to implement its model, such as the assumption that average growth will initially be only 3.7 percent, and after 2008, will be 6.5 percent. The Company prefers the assumption in the FERC model that it will take many years before the terminal growth rate will be the same as gross domestic product ("GDP") growth, and the fact that the model therefore gives greater weight to the estimate of near term, stage 1 growth. As for stage 2 growth estimates, the Company also prefers to use the geometric average annual GDP growth rate, which is 6.4 percent, rather than Staff's use of the arithmetic average annual GDP growth rate, which is 6.8 percent. The inputs preferred by Dr. Zepp lead to

higher equity cost estimates.

The Company also finds Staff's use of the CAPM model in estimating its equity cost problematic. Dr. Zepp criticizes the Staff's assumption in the CAPM that Chaparral City has the same beta[5] as the average beta of the six publicly traded water utilities in the sample group, 0.68, because, in his opinion, Chaparral City is a more risky operation than the public utilities in the sample group and would have a beta closer to 1.0, which would result in a higher equity cost estimate (Zepp Rb. at 22). Dr. Zepp is also critical of Staff's selection of the average yield on five, seven and ten year Treasury Securities for its risk-free rate, on the basis that most investors hold securities for a five to ten year period (*see* Ramirez Dt. at 26-27). The Company argues that the investors' holding period is not relevant, and Staff's choice reduces the equity cost estimate. The Company would instead prefer the use of a long-term Treasury Bond rate as the risk-free rate (Zepp Rb. at 18-19). The Company further argues that although Staff has used an average of intermediate-term Treasury rates as the risk-free rate, Staff used the long-term Treasury rate to estimate the market risk premium and claims that this creates a mismatch (Zepp Rj. at 15). The Company also argues that recent empirical studies of the CAPM have shown that the returns estimated for low data stocks like the water utility sample group are too low relative to required returns for average risk stocks (Tr. at 245), and quotes an article published last year by Drs. Eugene Fama and Kenneth French which concludes that "despite its seductive simplicity, the CAPM's empirical problems probably invalidate its use in applications."[6] On rejoinder, Dr. Zepp restated Staff's CAPM equity cost estimates using its preferred inputs, and reached an equity cost estimate of 10.2 percent (Zepp Rj. at 15-17). The Company argues that this updated CAPM estimate is conservative for the reasons stated in its criticism of the CAPM.

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[5] Beta measures the systematic risk of a company. The market's beta is 1.0; therefore, a security with a beta higher than 1.0 is riskier than the market, and a security with a beta lower than 1.0 is less risky than the market.

[6] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence" 18 *Journal of Economic Perspectives* 25-46 (Summer 2004).

While the Company does not disagree regarding the basic formula RUCO used to derive its sustainable growth rate to derive its estimate of dividend growth, the Company argues that RUCO's witness Rigsby's reliance on his personal analysis of *Value Line* forecasts depresses his dividend growth estimate and reduces the equity cost produced by Mr. Rigsby's DCF model (Zepp Rb. at 31-33; Tr. at 296-99). Dr. Zepp claims that RUCO's dividend growth estimate is flawed in that its external "sv" growth rate includes an understated estimate of the stock financing rate ("s") compared to forecasted stock financing rates (Zepp Rb. at 32, Rebuttal Table 15). Dr. Zepp is also critical of RUCO's estimates of the "v" in its external growth rate, and asserts that that there is no evidence supporting Mr. Rigsby's opinion, based on Dr. Morin's text on regulatory finance (*see* Hearing Exhibit A-16), that the market prices of a utility stock will move toward book value. Using equity cost estimates based on Mr. Rigsby's data, but using different inputs, Dr. Zepp produced a restatement of RUCO's constant growth DCF model in two different ways. Dr. Zepp used RUCO's dividend yields, adjusted RUCO's historical average retention growth rate ("br") growth rate and stock financing ("vs") growth rate estimates to reach an equity cost of 10.7 percent (Zepp Rb. at 31-33 and Rebuttal Tables 15 and 16). Dr. Zepp performed another restatement of RUCO's DCF analysis using forecasts of growth instead of sustainable growth and reached an equity cost estimate of 10.6 percent (Zepp Rj. at 22 and Rejoinder Table 9).

2. Staff

Staff's witness Ramirez prepared estimates of the cost of equity using market-based models: a constant-growth DCF model, a multi-stage, or non-constant growth DCF model, and a CAPM analysis. To calculate dividend yield in its constant-growth DCF calculation, Staff divided the expected annual dividend as forecasted by *Value Line* by the spot stock price on April 20, 2005. Staff states that it used a spot stock price, rather than a historical average of stock prices, in order to be consistent with the efficient markets hypothesis of finance theory, which holds that the current

stock price includes investors' expectations of future returns and is the best indicator of those expectations.[7] Staff then added the resulting dividend yield to its estimate of a dividend growth rate. To reach its dividend growth rate determination, Staff used a combination of historical and projected dividend-per-share ("DPS") growth provided by *Value Line*, and also examined historical and projected growth in earnings-per-share ("EPS") and intrinsic growth. Staff's analysis produced an average of historic and projected growth rates of 5.8 percent, which when added to Staff's dividend yield calculation of 3.3 percent, produced Staff's constant growth DCF estimate of 9.1 percent. Staff's multi-stage DCF model incorporates two growth rates; a near term growth rate and a long-term growth rate to account for the assumption that investors expect dividends to grow at a non-constant rate in the near term (stage 1 growth) and then to grow at a constant rate in the long term (stage 2 growth) (Ramirez Dt. at 23). To calculate stage 1 growth, Staff forecasted four years of dividends for each of the utilities in the sample group using *Value Line's* expected dividends for the first year and projected DPS growth rate for the three subsequent years; and to estimate its stage 2 growth, Staff used the 6.5 percent rate of GDP growth from 1929 to 2003, which Staff believes is appropriate because it assumes that the water industry is expected to grow neither faster nor slower than the overall economy (Ramirez Dt. at 24). Staff reached a multi-stage DCF estimate of 9.5 percent. Staff calculated its overall DCF estimate of 9.3 percent by averaging the results of its constant-growth and multi-stage DCF estimates.

Staff also performed a CAPM analysis using a historical market risk premium estimate, reaching an estimate of 9.1 percent, and a current market risk premium estimate, reaching an estimate of 9.3 percent, to reach its overall CAPM estimate of 9.2 percent (Ramirez Dt. at 25-29). Based on its DCF and CAPM estimates, Staff recommends a cost of equity of 9.3 percent.

[7] Ramirez Dt. at 15. Use of spot market price has been adopted in recent Commission Decisions, including *Arizona Water Company*, Decision No. 66849 (March 19, 2004), and *Arizona-American Water Company*, Decision No. 67093 (June 30, 2004).

Staff disagrees with the Company's use of the FERC DCF analysis because it miscalculates dividend yields and relies only on analysts' forecasts, which are overly optimistic (Ramirez Dt. at 40-41). Staff states that the FERC DCF multi-stage analysis relies more heavily on analysts' forecasts than on GDP growth, and asserts that it is more reasonable to rely on the GDP than on analysts' forecasts, which are known to be overly optimistic (Ramirez Dt. at 42-45). Staff further argues that the FERC multi-stage DCF analysis assumes that the water industry will grow indefinitely at a rate that outpaces the historical GDP growth, which is impossible. Staff also asserts that Dr. Zepp's modification of Staff's multi-stage DCF analysis introduces a supernormal growth stage between stage 1 and stage 2 growth in Staff's model (Ramirez Sb. at 10). Staff addresses Dr. Zepp's criticism of its use of the geometric average, and not the arithmetic average, of GDP growth. Staff states that while the arithmetic mean represents typical performance over single periods, it is more appropriate to use the geometric average because it better represents long-term performance (Ramirez Sb. at 11).

Staff is also critical of Chaparral City's use of the CPUC staff's risk premium analysis to estimate its cost of equity, because the risk premium analysis erroneously assumes that accounting ROEs are equal to the cost of equity. Staff states that this assumption is contrary to the basic proposition in finance that cost of equity is less than the allowed rate of return on equity, and argues that the risk premium analysis used by the CPUC staff is flawed due to its suggestion that investors' actual cost of equity is lower than historical or book ROE. Staff believes that reliance on a risk premium analysis comparing allowed ROEs to the cost of equity is misplaced because it is capital markets, not regulatory commissions, that determine the cost of equity. Staff argues that although certain ROEs may have been allowed in prior regulatory decisions, there are numerous factors which are not always identified in a commission decision that may have influenced the rate of return approved in a particular proceeding; that the particulars behind each case cannot always be known; and that even if the particulars were known, the witnesses who testified in those past cases are not

available for cross-examination in this case (Ramirez Dt. at 51).

Staff is also critical of Dr. Zepp's use of forecasted interest rates, rather than spot market rates, to conduct his risk premium analysis. Staff asserts that Dr. Zepp's reliance on forecasts of ten-year Treasury securities, long-term Treasury securities, and Baa corporate bond rates are biased, and argues that the best forecast of tomorrow's yield is simply today's yield (Ramirez Dt. at 47-49). In response to Dr. Zepp's argument that the sample water companies Staff used are not representative of Chaparral City because Chaparral City has more systematic risk than the sample companies, Staff argues that Chaparral City and the sample water companies are in the same business and should have on average the same systematic risk, and that no evidence was submitted to support the Company's claim otherwise with regard to potential rate base disallowances, existence of or lack of adjustment mechanisms, or transitions to a multi-tier declining block rate design (Ramirez Dt. at 35-39). Staff argues that market risk is related to economy-wide perils that affect all businesses, such as inflation, interest rates and general business cycles, and that unique risk does not affect the cost of equity, because firm-specific risk can be eliminated through shareholder diversification. Staff asserts that its assumption that all water companies have similar betas is therefore reasonable, and states that even if Staff had not performed a CAPM analysis, its cost of equity recommendation would still be 9.3 percent based on its DCF estimates.

3. **RUCO**

RUCO believes that given the current environment of low inflation and low interest rates, its 9.45 percent cost of equity estimate is reasonable; that despite the fact that Chaparral City's equity level is slightly higher than the average of the sample companies (59 percent as compared to 56 percent) RUCO did not make a downward adjustment to its DCF estimates; that its DCF growth rate estimates exceed analysts' growth rates by 49 to 60 basis points; and that its recommended 9.45 percent cost of equity estimate is extremely close to the 9.50 ROE *Value Line* projection for

American States, Chaparral City's parent, for the 2005 operating period (Rigsby Dt. at 41). RUCO is critical of the Company's reliance on securities analysts' projections alone to arrive at its estimates of growth without attributing any significance to historical data, and points out that Mr. Rigsby's estimates take into account the fact that past projections of *Value Line* analysts have tended to be somewhat higher than the actual returns on the common equity of water utilities. RUCO states that its methodology for determining the "sv" component of Mr. Rigsby's DCF growth figure, rather than being subjective, as the Company charges, objectively relies on the work of Dr. Roger A. Morin as well as other academics in the field of finance and the resulting theory that the market price of a utility's common stock will move toward book value, or a market to book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (Rigsby Dt. at 16; Tr. at 318-22; Hearing Exhibit A-16). RUCO points out that while the Company believes Mr. Rigsby's growth estimates are too low, his average "br + sv" growth estimate is 60 basis points higher than the average of *Value Line's* projections on EPS, DPS, and book value per share; that his growth estimate is 185 basis points higher than the average projections of analysts at *Value Line,* and 470 basis points higher than *Value Line's* 5-year average of historical data for the water utilities it follows (Rigsby Dt. at 21).

4. Conclusion

The Company, Staff and RUCO all used a DCF model. The Company's estimates varied significantly from Staff and RUCO's estimates due primarily to differences in its dividend growth estimation. We note that while the Company criticized Staff and RUCO for choosing inputs that "depressed" their cost of equity estimates, the Company's choices resulted in higher cost of equity estimates. We agree with Staff and RUCO that relying solely on analysts' forecasts of the short-term growth rate of the water industry may be unreasonable, and believe that averaging past growth rates with growth rate forecasts produces a more reasonable estimate, because analysts' forecasts are known to be optimistic. We are not convinced that the methodology FERC uses to estimate cost of

capital for the energy and gas industry companies it regulates is appropriately applied to monopoly water utilities. We disagree with the use of a risk premium analysis for cost of equity estimation for the reasons Staff states, as set forth above. We find, after examining the evidence presented, that Staff's DCF methodology provides a more reasonable cost of equity estimate than the Company's. Staff's analysis is based on sound economic principles, and produces a cost of equity estimate that represents a fair and reasonable estimate of Chaparral City's cost of equity for purposes of this proceeding, and will produce a return commensurate with returns on investment in other enterprises with risk corresponding to that of the Company. As described above, Staff arrived at a 9.3 percent cost of equity estimate through application of both the constant growth and multi-stage DCF models and the CAPM.

C. Cost of Capital Summary

	Percentage	Cost	Weighted Cost
Long-Term Debt	41.2%	5.1%	2.1%
Common Equity	58.8%	9.3%	5.5%
Weighted Average Cost of Capital			7.6%

VIII. RATE OF RETURN

Chaparral City advocates that its proposed cost of capital be adopted as a rate of return to be applied to its FVRB to determine required operating income (Bourassa Rb. at 2). Staff recommends that the weighted average cost of capital be used to determine a fair value rate of return in accordance with the Commission's traditional rate of return methodology. As stated earlier, RUCO recommends that its recommended OCRB be adopted as the Company's FVRB without regard to the Company's RCND, and recommends that its proposed weighted average cost of capital be applied to the resulting FVRB.

The Company claims that both Staff and RUCO "ignored FVRB" when they multiplied their recommended rates of return by their recommended OCRBs to determine Chaparral City's operating

income, and then divided the operating income by the FVRB to compute a fair value rate of return (Co. Br. at 6-7). The Company claims that this methodology results in rates based solely on original cost rather than fair value (*Id.*). The Company further claims that the approach advocated by Staff and RUCO violates the fair value standard (Co. Br. at 10).

RUCO argues that this Commission has historically and consistently averaged a utility's OCRB and RCND to determine a FVRB and then computed a fair value rate of return to apply to FVRB in calculating operating income (RUCO Reply Br. at 3). RUCO asserts that the Company is attempting to persuade the Commission to approve an operating income methodology that considers rate base and rate of return on two different bases, and that its arguments should be rejected, because if rate base and rate of return are not stated on the same basis, operating income will be overstated (RUCO Br. at 1-2).

Staff states that in this case, Staff has considered and recommended a finding of fair value and a fair rate of return on that fair value. Staff states that in order to ensure that the Company is given the opportunity to earn a fair rate of return on the fair value of its plant, Staff proposed a cost of capital analysis, and based on its analysis, proposed a weighted average cost of capital which, when applied to the Company's OCRB, yields just and reasonable rates. Staff further states that its recommended FVRB similarly provides the Company with an opportunity to earn its cost of capital, and that allowing a higher rate of return on the Company's FVRB than the return Staff recommends would provide the utility with an opportunity to earn windfall profits, and would not yield just and reasonable rates as required by Article XV, Section 3 of the Arizona Constitution (Staff Br. at 8).

We disagree with the Company's assertion that the rate of return methodology used by this Commission to determine revenue requirement violates the fair value standard. The Company attempts to equate the weighted average cost of capital to a rate of return, when in fact, this cost of capital estimate is used as a tool to determine a just and reasonable rate of return. The rate of return

methodology and resulting revenue increase proposed by Chaparral City would produce an excessive return on FVRB. There has been no legitimate basis presented for departing from the traditional ratemaking methodology of applying a fair value rate of return to the Company's FVRB in this proceeding. For the reasons advocated by Staff and RUCO, we find that applying a fair value rate of return to the FVRB is just, reasonable, and in accord with the mandates of the Arizona Constitution, and will adopt it in this case.

IX. AUTHORIZED INCREASE/DECREASE

With the adjustments adopted herein, the adjusted test year operating income is $614,247. The 7.6 percent cost of capital translates into a 6.36 percent fair value rate of return on FVRB of $20,340,298 as authorized hereinabove. Applying the 6.36 percent rate of return to the FVRB produces required operating income of $1,294,338. This is $680,091 more than the Company's test year adjusted operating income. Multiplying the deficiency by the gross revenue conversion factor of 1.6286 results in an increase in revenues of $1,107,596, or a 17.86 percent net increase over test year adjusted revenues.

X. RATE DESIGN

In its rate application, the Company proposed a two-tier, inverted block rate design, with different breakover points for each size meter based on its cost of service study (Kozoman Dt. at 11-20, Exh. A-14, Sched. G-1 through G-9). In its rebuttal filing, the Company accepted nearly all of the elements of Staff's proposed rate design, including the use of three inverted commodity rate tiers for residential customers on ¾-inch meters, with all other customers having two inverted commodity rate tiers; Staff's recommended breakover points between tiers; elimination of the current additional charge to recover costs for pumping water to elevation zones two and three; elimination of the 1,000 gallons of water in the monthly minimum charge; and the continuation of a single, uniform volume rate for irrigation water service (Kozoman Rj. at 34, Tr. at 771-74). Staff's recommended breakover

points for ¾-inch residential meters are 3,000 gallons and 9,000 gallons; and for ¾-inch commercial and industrial meters, one breakover point of 9,000 gallons; with increasing single breakover points as meter sizes increase. The Company states that it recognizes the importance of encouraging water conservation, including the use of rate design to encourage customers to implement conservation measures and reduce their water use (Co. Reply Br. at 37). The Company disagrees, however, with Staff's recommended spread between the commodity rates and also with the commodity rates Staff recommends for irrigation water service.

Chaparral City contends that Staff's recommended inverted tier rate design with its proposed spread between commodity rates may lead to reduced water use by customers, and that if it does, the rate design will impact its ability to earn its authorized rate of return. The Company believes that Staff is actually proposing a "lifeline" rate because Staff's recommended commodity rate for the first tier is below the Company's existing commodity rates, and is only applicable to residential customers on ¾" meters, and that Staff is using the subsidy of the lower rate for first tier usage to create a larger spread between the tiered commodity rates. The Company asserts that rates should be designed in a way that accounts for possible reductions in water use (Co. Br. at 54-55), and urges that the risk that a new rate design may lead to under-recovery of the Company's authorized revenue requirement should be recognized in the return on equity authorized in this proceeding (*Id.* at 58). Taking the alternative point of view, the Company also argues on brief that if Staff's recommended rate design will not reduce existing customers' water usage, it should not be required to implement inverted tier rates (Co. Br. at 59).

Staff asserts that its inverted tier rate design was developed to promote long term conservation goals, and includes commodity rates that are spread far enough apart to send appropriate price signals to customers regarding the importance and value of water, which is a limited resource in this state. Staff disputes the Company's assertion that its first tier is a "lifeline" rate, because its proposal is not

designed according to income level, but instead is focused on sending an appropriate price signal based on customers' meter size and usage (Staff Br. at 4). Staff states that it cannot predict whether customers will actually decide to use less water in a particular year; that no evidence was presented supporting the Company's claim that there will be a significant short-term change in water use as a result of the implementation of inverted-tier rates; and that the Company's service area still has a rapidly-growing customer base (Staff Reply Br. at 3).

RUCO proposes a rate design that charges each customer the same commodity rate for the same level of usage (RUCO Br. at 14). RUCO's three tier inverted block rate structure has its first breakover point at 8,000 gallons, the present average residential usage, with the second breakover point at 73,000 gallons, which it calculated based on the average of the Company's original proposed graduated breakover points (Moore Dt. at 32). RUCO believes this rate design provides a balanced approach that does not discriminate between classes or meter sizes, and that since its breakover points are based on average customer usage, provides a price incentive against above-average use, which could result in the conservation of water resources (RUCO Reply Br. at 9).

The Company disagrees with RUCO's rate design because it shifts revenue recovery away from residential customers, who have smaller meters, and onto commercial and industrial customers, who have larger meters. The Company believes that RUCO's rate design is inequitable to customers on larger sized meters because customers with smaller meters will have a substantial portion of their usage fall into the lower-priced rate block, with little of their usage reaching into the highest price rate block, while customers with larger meters will have the bulk of their usage fall into the higher tiers, without regard to whether their water usage is excessive or wasteful.

Of the rate designs presented, we find that Staff's proposal best addresses the goals of conservation, efficient water use, affordability, fairness, and simplicity.[8] We find also that the risk of

[8] Public comment was presented concerning the Company's irrigation rates as originally proposed by the Company. We note that the irrigation commodity rate we approve herein remains lower than other commodity rates.

revenue instability that the Company fears is sufficiently offset by the current growth in the Company's customer base to allow the implementation of a conservation-oriented rate design at this time. Although the Company provided testimony speculating that Staff's proposed rate design might cause such drastic reductions in water usage that the Company would be unable to recover its authorized revenue requirement, we do not find this conjecture convincing. As Staff's uncontroverted growth analysis demonstrates, the Company still has a growing customer base (*see* Scott Dt., Exhibit MSJ at 5), and new growth will be available to compensate for possible reductions in usage by existing customers, if demand proves to be elastic and existing customers respond to the conservation signals by reducing their usage in response to the new rate design. If, even with customer growth, the Company finds it is not recovering its authorized revenue requirement, it is within the Company's control to file a rate case. After considering the evidence presented, we find that it is in the public interest for the Company to implement the conservation-oriented rate design proposed by Staff.

XI. OTHER ISSUES

A. Automatic Adjustment Mechanisms

The Company requests approval to implement automatic adjustment mechanisms which would allow the Company to directly pass through to its ratepayers increases and decreases in two of its most significant operating expenses, purchased water and power costs, through a surcharge mechanism.[9] Staff and RUCO recommend against approval of the requested adjustment mechanisms.

Approximately 90 percent of the Company's water supply comes from Central Arizona Project ("CAP") water delivered through the Central Arizona Water Conservation District ("CAWCD") (Hanford Rb. at 3). Under its subcontract with the United States and CAWCD,

[9] Adjusted test year purchased water costs are $823,781 and adjusted test year purchased power costs are $510,947.

Chaparral City pays an annual water service capital charge, based on its total CAP allocation, and a separate delivery charge based on the amount of CAP water actually used (Hanford Dt. at 6). Chaparral City is also a member of the Central Arizona Groundwater Replenishment District ("CAGRD") administered by CAWCD. The Company pays fees to the CAGRD for groundwater replenishment services based on the quantity of ground water pumped (Hanford Dt. at 6-7). The Company's witness claims that based on the advisory rates published by CAWCD for the years 2006, 2007 and 2008, purchased water costs will increase over the adjusted test year level by more than $50,000 per year by 2008 and that these increases will amount to over $100,000 of unrecovered water expense over the three year period (Bourassa Rj. at 24).

Chaparral City purchases power from both APS and SRP. The Company projects annual expense increases from SRP and APS of over 5 percent per year over adjusted test year levels (Co. Br. at 24).

Staff agrees that the Company's purchased water costs are significant, but in contrast to the Company's estimate that its purchased water expense will increase by more than $50,000 per year, Staff's analysis of advisory rates showed that the Company's purchased water expense will not increase over test year levels by $50,000 until 2008 (Exh. S-7, Exh. 5). Staff does not believe that the incremental cost level or volatility associated with possible rate increases or decreases associated with the Company's water supply are significant enough to justify a purchased water adjustment mechanism in this case, and recommends denial of the Company's request. Regarding purchased power expense, Staff does not disagree that purchased power expense is a significant cost for Chaparral City, but points out that the issue to be considered in implementing an adjustment mechanism is not merely whether the cost is significant, but whether the incremental cost level, or volatility, associated with possible rate increases or decreases is significant. Staff asserts that the future rate increases the Company projects from SRP and APS do not constitute a level of volatility

great enough to warrant the need for a purchased power adjustment mechanism. In particular, Staff differentiates the possible increases in Chaparral City's purchased power expense from the volatility of APS' constantly changing fuel and purchased power costs, which led to the Commission's recent approval of a Power Supply Adjustor for APS.

We do not disagree with the Company that its purchased water and purchased power expenses are significant. However, we agree with Staff and RUCO that these expenses do not constitute a level of volatility that would justify the extraordinary ratemaking treatment that the Company requests. As we stated in Decision No. 56450, there is a danger of piecemeal regulation inherent in adjustment mechanisms. Because adjustor mechanisms allow automatic increases in rates without a simultaneous review of a Company's unrelated costs, an adjustment mechanism has a built-in potential of allowing a Company to increase rates based on certain isolated costs when its other costs are declining, or when overall revenues are increasing faster than costs due to customer growth. Such circumstances can result in increases to ratepayers through adjustors even when the Company's level of earnings would not warrant a rate increase, such that the utility's net income is increased outside a rate case. In addition, as we stated in Decision No. 66849 (March 19, 2004), adjustment mechanisms may also provide a disincentive for a utility to obtain the lowest possible cost commodity because the costs are simply passed through to ratepayers. For these reasons, adjustment mechanisms should be implemented only under very special circumstances. Based on the evidence in this proceeding, circumstances do not exist in this case to justify the risks of piecemeal regulation inherent in adjustment mechanisms, and we will not approve the Company's requests.

On July 28, 2005, the Company filed a request that administrative notice be taken of an application filed on July 22, 2005 in Docket No. E-01345A-05-0526 by APS requesting recovery of $100 million in unrecovered fuel and purchased power costs through the Power Supply Adjustor mechanism approved in Decision No. 67744 (April 7, 2005). The July 28, 2005 filing also requested

that administrative notice be taken of SRP's announcement that it intends to increase its residential and business rates on or about November, 2005. The Company asserts that the APS filing and the SRP announcement are relevant to its request for authorization of a purchased power adjustment mechanism.

We note that the Commission has not ruled on the APS PSA request, and that the SRP announcement indicated an effective date of November 2005. This means that future changes in SRP's rates, and any changes to APS' rates resulting from its July 22, 2005 filing, will take place more than one and a half years following the end of the 2003 test year in this case. As explained above, the expenses we approve herein already include an adjustment for known and measurable post-test year changes in the Company's electricity costs. The Company indicated that it is likely to file another rate case within three to four years (Tr. at 647; Bourassa Dt. at 14). If the Company experiences a further increase in costs during 2006 as a result of the anticipated SRP increase, or as a result of a Decision on the APS filing, it will be appropriate to examine such increases in the context of the Company's other concurrent expenses, rather than simply authorizing the Company to pass those costs through to ratepayers.

B. Depreciation Rates

The Company is proposing to utilize the depreciation rates proposed by Staff on a going forward basis. Staff has developed typical and customary depreciation rates within a range of anticipated equipment life by individual National Association of Regulatory Utility Commissioners ("NARUC") category (Scott Dt., Exhibit MSJ at 7, 16). These are the depreciation rates that have been adopted in recent rate cases (*See, e.g.* Decision No. 67279 (October 5, 2004) (Rio Rico Utilities, Inc.)). RUCO disagrees with the use of these depreciation rates, which it states are among the highest rates the Commission has recently approved. In the absence of a depreciation study, which would have provided a definitive set of depreciation rates, RUCO proposes depreciation rates that it states

represent an average of 24 different water systems. The Company criticizes the methodology RUCO used to develop its proposed depreciation rates, because it mixes composite rates with individual depreciation rates by plant category in order to calculate average rates, and because the resulting depreciation rates were not compared with the expected useful lives of the assets to which they would be applied (Tr. at 554-555). We find that the Staff proposal more closely estimates the expected life of the Company's assets than RUCO's proposal, and will order the Company to adopt the typical and customary depreciation rates that Staff has developed as set forth in Mr. Scott's Direct Testimony, Exhibit MSJ at 16.

C. Cross-Connection and Backflow Prevention Tariff

Attached to Company witness Mr. Hanford's direct testimony was a proposed cross-connection and backflow prevention tariff. There was no objection or comment on the proposed tariff during this proceeding and the Company requested that it be approved. We will therefore approve it and require that a conforming copy of the tariff be filed along with the tariffs for its new rates.

D. Water Service Curtailment Tariff

Also attached to Mr. Hanford's direct testimony was a water service curtailment tariff. In Staff's direct testimony, Staff proposes an alternative form of tariff similar to tariffs approved in the past for Class A water utilities. The Company is in agreement with Staff's proposed form of tariff and requests that it be approved. Staff recommends that the Company be directed to file a copy of a water service curtailment tariff within 45 days of this Decision, for Staff's review and certification. We will therefore direct the Company to file a copy of the tariff in conformance with the form of tariff attached to the direct testimony of Mr. Scott in Exhibit MSJ at 8, within 45 days of this Decision, for Staff's review and certification.

E. Non-Account Water

Staff notes in its direct testimony that Chaparral City's non-account water was over 11 percent, which exceeds Staff's recommendation that non-account water should be 10 percent or less. Staff states that the Company is aware of its non-account water and believes that some of its meters are being under read and that the Company is currently monitoring its meter reading practices. Staff recommends that the Company docket the results of meter monitoring as a compliance item in this case by July 30, 2006; that if the reported water loss for the period from June 1, 2005 through June 1, 2006 exceeds 10 percent, that the Company be required to prepare either a report containing a detailed analysis and a plan to reduce non-account water to below 10 percent, or to submit a cost-benefit analysis demonstrating that it is not cost-effective to reduce non-account water below 10 percent. The Company did not object to Staff's recommendation. We will adopt Staff's recommendation in this case.

F. Arsenic Issues

As noted above, 90 percent of Chaparral City's water supply consists of treated CAP water. However, the Company has two active wells, Well Number 10 and Well Number 11, which show concentrations of arsenic slightly above the 10 parts per billion maximum contaminant level ("MCL") for arsenic that will become effective in January, 2006 (Scott Dt., Exh. MSJ at 5). Staff notes in its direct testimony that a blend line has already been constructed to Well Number 10 and that the Fountain Hills Boulevard main will be used to blend CAP water with ground water from Well Number 11 (*Id.*). The Company does not object to Staff's recommendation that the Company be required to submit, by November 30, 2005, a plan describing how the Company will comply with the new arsenic MCL when the CAP canal is out of service. We find this recommendation to be reasonable and will adopt it.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. Chaparral City is a public service corporation engaged in providing water utility service to approximately 12,000 customers located in the northeastern portion of the Phoenix metropolitan area, including the Town of Fountain Hills and a small portion of the City of Scottsdale under authority granted by the Commission in Decision No. 41243 (April 20, 1971). The Company's business office is located at 12021 N. Panorama Drive in Fountain Hills, Arizona, 85268.

2. Chaparral City is currently charging rates approved in Decision No. 57395 (May 23, 1991), based on a test year ended December 31, 1988.

3. Chaparral City is an Arizona corporation wholly owned by American States Water Company, which is publicly traded on the New York Stock Exchange. American States' primary operating subsidiary is Southern California Water Company.

4. In October 2000, as approved in Decision No. 62909 (September 18, 2000), American States purchased Chaparral City's stock from MCO Properties, Inc., the real estate developer that owned and operated Chaparral City.

5. On August 24, 2004, Chaparral City filed with the Commission an application requesting an increase in revenues of $1,797,182.

6. On September 14, 2004, RUCO filed an Application to Intervene, which was granted. No other requests for intervention were filed.

7. On September 23, 2004, Staff filed a letter stating that the Company's application met the sufficiency requirements set forth in A.A.C. R14-2-103, and classifying the Company as a Class A utility.

8. On September 28, 2005, a Procedural Order was issued setting this matter for hearing and setting related procedural deadlines.

9. On February 15, 2005, the Company filed a Notice of Publication certifying that public notice was published in *The Fountain Hills Times* on January 26, 2005. Public notice of the

application and hearing was also mailed to each of the Company's customers in their January 2005 bills.

10. Written public comments in opposition to the amount of the requested rate increase were received on February 10, February 14, February 28, March 10, March 23, April 8, April 20, April 21, May 24, May 31,[10] and June 14, 2005.

11. A hearing was held as scheduled commencing on May 31, 2005 and continuing on June 1, June 6 and June 8, 2005.

12. Public comment opposing the proposed increase in irrigation rates was provided on May 31, 2005 by Ken Watkins, the golf course superintendent of the FireRock Country Club. Mr. Watkins also filed written public comment in this docket on March 23, 2005 and June 14, 2005. Mr. Watkins stated that FireRock would be adversely impacted by the rate increase because even though the golf course uses effluent when possible, it sometimes must rely on potable water.

13. Public comment against the proposed increase in irrigation rates was also provided on May 31, 2005 by Joe Miller, the golf course superintendent of The Golf Club at Eagle Mountain. Mr. Miller also stated that his golf course sometimes must use potable water for irrigation, and that it would be adversely affected by the proposed rate increase. Mr. Miller also filed written public comment in this docket on April 8, 2005 and May 24, 2005. Don Rea, the General Manager of The Golf Club at Eagle Mountain also filed a letter dated April 5, 2005 opposing the increase in irrigation rates on April 21, 2005 and again May 24, 2005.

14. For ratemaking purposes, Chaparral City's OCRB, RCND and FVRB for the test year ended December 31, 2003 are determined to be $17,030,765, $23,649,830, and $20,340,298, respectively.

15. With the adjustments adopted herein, the adjusted test year operating income is $614,247.

16. The 7.6 percent cost of capital translates into a 6.36 percent fair value rate of return on FVRB of $20,340,298 as authorized hereinabove. Applying the 6.36 percent rate of return to the

[10] The public comment letter filed on May 31, 2005 (the date the hearing commenced) included a request by a customer that a "rate adjustment" made in 2003 be investigated. If the Commission's Consumer Services Section has not already done so, it should promptly contact this customer, and inform the Commission if further action is required.

FVRB produces required operating income of $1,294,338. This is $680,091 more than the Company's test year adjusted operating revenue. Multiplying the deficiency by the gross revenue conversion factor of 1.6286 results in an increase in revenues of $1,107,596, or a 17.86 percent net increase over test year adjusted revenues.

17. The rates set herein result in a monthly increase of $3.83, from $30.49 to $34.32, or 12.57 percent, for the average usage residential customer (9,187 gallons), and a monthly increase of $2.41, from $22.53 to $24.94, or 10.70 percent, for the median usage (5,501 gallons) residential customer.

18. The rate of return methodology and resulting revenue increases proposed by Chaparral City would produce an excessive return on FVRB.

19. It is in the public interest to implement a rate design that promotes long-term conservation goals.

20. The rate design approved herein addresses the goals of conservation, efficient water use, affordability, fairness, simplicity, and revenue stability, and is in the public interest.

21. The methodology adopted herein for estimation of property tax expense fairly estimates property tax expense.

22. Based on the evidence presented, circumstances do not exist in this case to justify the risks of piecemeal regulation inherent in adjustment mechanisms, and Chaparral City's request to implement automatic adjustment surcharge mechanisms for its purchased power and purchased water costs will not be approved.

23. The typical and customary depreciation rates developed by Staff as set forth on page 16 of Exhibit MSJ attached to the Direct Testimony of Staff witness Mr. Scott are just and reasonable and should be used by Chaparral City on a going-forward basis.

24. The cross-connection and backflow prevention tariff attached to the Direct Testimony of Mr. Hanford is reasonable and should be approved. Chaparral City should be required to file a conforming copy of the tariff when it files the tariffs setting forth the new rates we approve herein.

25. Staff's recommendation that the Company be directed to file a copy of a water service curtailment tariff that conforms to the form of tariff attached to the direct testimony of Mr. Scott in

Exhibit MSJ at 8, within 45 days of this Decision, for Staff's review and certification, is reasonable and should be adopted.

26. Staff's recommendation regarding meter monitoring and reporting in relation to Chaparral City's 11 percent test year level of non-account water is reasonable and should be adopted.

27. Staff's recommendation that Chaparral City be required to submit, by November 30, 2005, a plan describing how it will comply with the new arsenic MCL when the CAP canal is out of service, is reasonable and should be adopted.

28. Because an allowance for the property tax expenses of Chaparral City Water Company, Inc. is included in the Company's rates and will be collected from its customers, the Commission seeks assurances from the Company that any taxes collected from ratepayers have been remitted to the appropriate taxing authority. It has come to the Commission's attention that a number of water companies have been unwilling or unable to fulfill their obligation to pay the taxes that were collected from ratepayers, some for as many as twenty years. It is reasonable, therefore, that as a prophylactic measure Chaparral City Water Company, Inc. annually file, as part of its annual report, an affidavit with the Utilities Division attesting that the Company is current in paying its property taxes in Arizona.

29. As discussed herein, it is reasonable to require Chaparral City to cease charging hook-up fees until such time that it has an approved hook-up fee tariff on file.

30. The Maricopa County Environmental Service Department has determined that the Company's system is currently delivering water that meets water quality standards required by Title 18, Chapter 4 of the Arizona Administrative Code.

31. The Company is located in the Phoenix Active Management Area ("AMA") and is therefore subject to the Arizona Department of Water Resources' water use and monitoring requirements. The AMA has reported that the Company is in compliance with its water use and monitoring requirements.

32. The fair value rate base, fair value rate of return, and rates and charges adopted herein are just and reasonable.

CONCLUSIONS OF LAW

1. Chaparral City is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. Sections 40-250 and 40-241.

2. The Commission has jurisdiction over the Company and the subject matter of the application.

3. Notice of the application was provided in the manner prescribed by law.

ORDER

IT IS THEREFORE ORDERED that Chaparral City Water Company, Inc. is hereby directed to file with the Commission on or before September 30, 2005, the following revised schedules of rates and charges:

MONTHLY USAGE CHARGE:
(All Zones and Classes)

¾" Meter	$ 13.60
1" Meter	22.70
1 ½" Meter	45.40
2" Meter	73.00
3" Meter	146.00
4" Meter	227.00
6" Meter	454.00
8" Meter	730.00
10 Meter	1,043.00
12 Meter	1,980.00
Fire Hydrants - Basic Service	No Monthly Usage Charge
Fire Hydrants – Used for Irrigation	$146.00

Commodity Rates Per 1,000 Gallons

¾" Meter (Residential)	
From 1 to 3,000 Gallons	$1.68
From 3,001 to 9,000 Gallons	2.52
Over 9,000 Gallons	3.03
¾" Meter (Commercial and Industrial)	
From 1 to 9,000 Gallons	2.52
Over 9,000 Gallons	3.03
1" Meter (Residential, Commercial and Industrial)	
From 1 to 24,000 Gallons	2.52
Over 24,000 Gallons	3.03

1 ½" Meter (Residential, Commercial and Industrial)	
From 1 to 60,000 Gallons	2.52
Over 60,000 Gallons	3.03
2" Meter (Residential, Commercial and Industrial)	
From 1 to 100,000 Gallons	2.52
Over 100,000 Gallons	3.03
3" Meter (Residential, Commercial and Industrial)	
From 1 to 225,000 Gallons	2.52
Over 225,000 Gallons	3.03
4" Meter (Residential, Commercial and Industrial)	
From 1 to 350,000 Gallons	2.52
Over 350,000 Gallons	3.03
6" Meter (Residential, Commercial and Industrial)	
From 1 to 725,000 Gallons	2.52
Over 725,000 Gallons	3.03
8" Meter (Residential, Commercial and Industrial)	
From 1 to 1,125,000 Gallons	2.52
Over 1,125,000 Gallons	3.03
10" Meter (Residential, Commercial and Industrial)	
From 1 to 1,500,000 Gallons	2.52
Over 1,500,000 Gallons	3.03
12" Meter (Residential, Commercial and Industrial)	
From 1 to 2,250,000 Gallons	2.52
Over 2,250,000 Gallons	3.03
Irrigation/Bulk (All Meters)	
All Gallons	1.56
Fire Hydrant Irrig./Const. (All Meters)	
All Gallons	1.56
(Standpipe) Fire Hydrants	

All Gallons	2.52
Fire Sprinklers	
All Gallons	2.52

Service Line and Meter Installation Charges	Meter	Line	Total
5/8" x ¾" Meter	$135.00	$385.00	$520.00
¾" Meter	215.00	385.00	600.00
1" Meter	255.00	435.00	690.00
1 ½" Meter	465.00	470.00	935.00
2" Turbine Meter	965.00	630.00	1,595.00
2" Compound Meter	1,690.00	630.00	2,320.00
3" Turbine Meter	1,470.00	805.00	2,275.00
3" Compound Meter	2,265.00	845.00	3,110.00
4" Turbine Meter	2,350.00	1,170.00	3,520.00
4" Compound Meter	3,245.00	1,230.00	4,475.00
6" Turbine Meter	4,545.00	1,730.00	6,275.00
6" Compound Meter	6,280.00	1,770.00	8,050.00
8" & Larger	At Cost	At Cost	At Cost

Establishment	$25.00
Establishment (After Hours)	35.00
Reconnection (Delinquent)	35.00
Reconnection (Delinquent and After Hours)	50.00
Meter Test	35.00
Deposit Requirement (Residential)	*
Deposit Requirement (Non Residential Meter)	*
Hydrant Meter Deposit	50.00
Deposit Interest	*
Re-establishment (within 12 months)	**
Re-establishment (after hours)	**
NSF Check	25.00
Deferred Payment, per month	1.50%
Meter Re-read	25.00
Charge of moving customer meter-Customer Requested	Cost
After hours service charge	Refer to above service charges
Late Charge per month	1.50%

Monthly Service Charge for Fire Sprinkler	
4" or smaller	$10.00
6"	10.00
8"	10.00

10"	10.00
Larger than 10"	10.00

* Per Commission rule A.A.C. R-14-2-403(B).

** Months off system times the monthly minimum per Commission rule A.A.C. R14-2-403(D).

*** 1% of monthly minimum for a comparable size meter connection, but no less than $5.00 per month. The service charge for fire sprinklers is only applicable for service lines separate and distinct for the primary water service line.

In addition to the collection of regular rates, the utility will collect from its customers a proportionate share of any privilege, sales, use and franchise tax, per Commission Rule R14-2-409D(5).

All advances and/or contributions are to include labor, materials, overheads and all applicable taxes, including all gross-up taxes for income taxes, if applicable.

IT IS FURTHER ORDERED that the revised schedule of rates and charges approved herein shall be effective for all service rendered after September 30, 2005.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall notify its customers of the revised schedules of rates and charges authorized herein by means of an insert in its next regularly scheduled billing in a form and manner acceptable to the Commission's Utilities Division Staff.

IT IS FURTHER ORDERED that the cross-connection and backflow prevention tariff attached to the Direct Testimony of Mr. Hanford is hereby approved.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc., shall file in Docket Control, as a compliance item in this case, a conforming copy of the cross-connection and backflow prevention tariff approved herein by September 30, 2005.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall file in Docket Control, as a compliance item in this case, within 45 days, a water service curtailment tariff conforming to the form of tariff attached to the direct testimony of Mr. Scott in Exhibit MSJ at 8, for Staff's review and certification.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall file in Docket Control, as a compliance item in this case, by November 30, 2005, a plan describing how it will comply with the United States Environmental Protection Agency rule regarding the maximum

contaminant level for arsenic when the Central Arizona Project canal from which it takes water delivery is out of service.

IT IS FURTHER ORDERED that in recognition of ongoing drought conditions in Arizona, the Company shall provide the Commission within 1 year of the effective date of this order detailed plans on how the Company's customers could increase the use of effluent and reduce their reliance on groundwater specifically as it pertains to golf courses, ornamental lakes and other aesthetic water features.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall annually file, as part of its annual report, an affidavit with the Utilities Division attesting that the Company is current in paying its property taxes in Arizona.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall cease charging hook-up fees until such time that it has an approved off-site facilities hook-up fee tariff on file.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall adopt the typical and customary depreciation rates developed by Staff as set forth on page 16 of Exhibit MSJ attached to the Direct Testimony of Staff witness Mr. Scott.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall file in this docket, as a compliance item in this case, by July 30, 2006, the results of its meter monitoring for the period from June 1, 2005 through June 1, 2006. If the reported water loss for the period from June 1, 2005 through June 1, 2006 exceeds 10 percent, Chaparral City Water Company, Inc. shall file, by September 30, 2006, either: 1) a report containing a detailed analysis and a plan to reduce non-account water to below 10 percent, or 2) a cost-benefit analysis demonstrating that it is not cost-effective to reduce non-account water below 10 percent.

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IT IS FURTHER ORDERED that Chaparral City Water Company, Inc.'s requests for approval of automatic adjustment mechanisms for its purchased water costs and purchased power costs are hereby denied.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 30th day of Sept., 2005.

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

DISSENT _____

DISSENT _____

SERVICE LIST FOR: CHAPARRAL CITY WATER COMPANY

DOCKET NO.: W-02113A-04-0616

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Dec

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona DOCKETED

NOV 01 2002

DOCKETED BY

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF BELLA VISTA WATER CO., INC. AN ARIZONA CORPORATION TO DETERMINE THE FAIR VALUE OF ITS PROPERTIES FOR RATE MAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES AND TARIFFS DESIGNED TO DEVELOP SUCH RETURN.

DOCKET NO. W-02465A-01-0776

DECISION NO. 65350

OPINION AND ORDER

EXHIBIT S-3 ADMITTED

DATE OF HEARING: July 25 and 26, 2002
August 16, 2002

PLACE OF HEARING: Tucson, Arizona

ADMINISTRATIVE LAW JUDGE: Jane L. Rodda

APPEARANCES: Mr. William Sullivan, MARTINEZ & CURTIS, P.C., on behalf of Bella Vista Water Company, Inc.;

Mr. Daniel W. Pozefsky, Staff Attorney, on Behalf of the Residential Utility Consumer Office;

Mr. Jason Gellman, Staff Attorney, Legal Divison, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

Procedural Background

Bella Vista Water Company, Inc. ("Bella Vista" or "Company") provides water utility services to approximately 6,659 residential and commercial customers in and around the City of Sierra Vista, in Cochise County, Arizona. Bella Vista filed an application to increase its rates with the Arizona Corporation Commission ("Commission") on September 28, 2001. The Company filed an amendment to its application on October 16, 2001. The Company used a test year of December 31, 2000. The Commission authorized Bella Vista's current rates in Decision No. 61730 (June 4.

1999).[1]

On October 29, 2001, the Commission's Utilities Division Staff ("Staff") notified the Company that its application was sufficient and that it is classified as a Class B utility.

The Commission granted intervention to the Residential Utility Consumer Office ("RUCO") on December 4, 2001.

By Procedural Order dated November 4, 2001, the Hearing Division established procedural guidelines for the conduct of the proceeding and set the matter for hearing to commence July 25, 2002, in Tucson, Arizona.

Pursuant to the procedural schedule, Staff and RUCO filed direct testimony on April 29, 2002. Bella Vista filed rebuttal testimony on May 28, 2002. Staff and RUCO filed surrebuttal testimony on June 18, 2002. Bella Vista filed rejoinder testimony on July 9, 2002.

On December 20, 2001, Bella Vista Mailed notice of the hearing on its rate application to its customers. The Commission has not received any comments from the public in response to the application.

The hearing convened as scheduled on July 25, 2002, and continued on July 26, 2002, and August 16, 2002. Ms. Judith Gignac, the Company's general manger, and consultants Messers. Ron Kozoman, CPA, and Ken Bourassa, CPA, testified for the Company; Ms. Marylee Diaz-Cortez and Mr. William Rigsby testified for RUCO; and Messers. Alexander Igwe, Lyndon Hammond and Joel Reiker, testified for Staff.

Staff, RUCO and the Company filed closing briefs on September 9, 12, and 13, 2002, respectively.

Summary of Issues

The Company claims test year operating revenues of $2,908,067, and test year operating expenses of $2,435,335, for an adjusted test year operating income of $472,732, a 6.3 percent rate of return on adjusted rate base. Bella Vista proposes that the Commission authorize a $388,766, or 13.38 percent, increase in revenues, based on a 9.5 percent return on a rate base of $7,488,816.

[1] Decision No. 61730 also approved the merger/consolidation of Bella Vista and Nicksville Water Co., Inc.

In support of its filing, the Company asserts that it has never earned the 10.75 percent return authorized in its last rate case (Decision No. 61730) and has made additions and improvements to its system, including $2.1 million of capital improvements financed by the Water Infrastructure Finance Authority ("WIFA"). The Company states it has accepted almost all of Staff's proposed adjustments to the income statement and rate base. The areas of dispute involving income are property taxes, professional and consulting costs, income taxes and depreciation expense. The disputed rate base issues are post-test year plant, cash working capital and deferred income taxes.[2] Bella Vista disagrees with both Staff and RUCO concerning the appropriate cost of capital.

RUCO determined that test year revenues were $2,908,067, which based on adjusted test year operating expenses of $2,385,278, produced operating income of $522,789, a 9.45 percent rate of return on adjusted rate base of $5,534,519. RUCO recommends that based on a weighted cost of capital of 9.66 percent, that the Commission authorize a rate increase of no more than $19,133, a revenue increase of 0.66 percent. RUCO recommends a reduction in water rates, but an increase in miscellaneous income.

Staff calculated that the Company had test year revenues of $2,907,775, and adjusted test year operating expenses of $2,395,005, producing operating income of $512,770, a 9.02 percent rate of return on an adjusted rate base of $5,687,016. Staff recommends that revenues be decreased by $86,727, or 2.87 percent, based on its proposed 8.1 percent rate of return on adjusted rate base. Staff's proposed return is based on the Company's current capital structure that includes $2.1 million in WIFA debt, although Staff excludes the plant financed by the debt from rate base.

Rate Base Issues

Bella Vista advocates a Fair Value Rate Base ("FVRB") of $7,488,816. Bella Vista accepts all of Staff's rate base adjustments except a) eliminating cash working capital; b) eliminating post-test year plant; and c) the calculation of deferred income tax credits. The Company did not accept RUCO's calculation of accumulated depreciation because it is based on applying a depreciation factor that was approved for the Nicksville Water Co., an entity that ceased to exist when it was

[2] The disputes over depreciation expense, income taxes and deferred taxes result from differences of opinion concerning appropriate expenses and rate base, and not on methodology.

merged with Bella Vista. Bella Vista also disagrees with RUCO's failure to accept Staff's adjustment to advances-in-aid-of-construction balances and deduction of customer deposits.

Post-Test Year Plant

The Company's Position

The most significant rate base issue is the inclusion of post-test year plant. The Company proposed including $1,797,279 of plant constructed after the end of the test year, but in service prior to the hearing.

The post-test year plant includes:

- Apache Booster Station ($131,120). This project involved installing a new well, booster station, and interconnecting two wells serving the Rail Oaks area. Mains were installed along Apache Point Road and continued in major streets. This project was intended to improve service in the Rail Oaks area which had been served by a single well and having difficulty meeting customer demands. The project was completed and in service on July 3, 2001.
- Rio Grand Well ($72,472). When the original well at Apache was determined to have insufficient production capacity to warrant development, the Company acquired a well easement at Rio Grande Road and Richards Road for a third well. This project included the land acquisition, the well drilling, and the main along Richards Road to connect the Rio Grande well with the Apache Point booster station and the Rail Oaks system. The facilities were completed and placed in service on December 12, 2001. Bills were not received until after the start of 2002 and the plant was not booked as in-service until 2002.
- SR92 Interconnection ($1,065,044). This project interconnects three systems- Welch, Nicksville and Rail Oaks with a 12 inch line, which increased availability and reliability of water service in the area of several low-producing wells. The first phase was completed and in service on August 30, 2001, and the third phase was completed and in service on October 23, 2001.

- SR 90 Interconnection ($176,709). This project ties two wells at the Vista View subdivision with the main Bella Vista system via a 12-inch line. It services the Sierra Vista Regional Health Center and the Cochise County Juvenile Center. It increases the reliability of the eastern portion of Bella Vista's system. Work was completed and the project in service on November 20, 2001.
- Colombo Avenue ($82,482). This project involved the installation of an 8 inch main in the extension of the arterial roadway and was completed and in service on October 1, 2001.
- Well # 18 ($115,993). Well #18 is one of the Company's major wells and serves the northwest quadrant of the City. It uses four booster pumps. This project involved rebuilding all four booster pumps and the re-coating and painting the interior and exterior of the 1.5 million gallon storage tank and two 5,000 gallon pressure tanks at the well site. The project was completed and in service on August 5, 2001.
- Line Replacement ($54,300). This project involved lowering and relocation of water mains as the City and County made road improvements. It was completed and in service June 8, 2001.
- Guilio Cesare Main ($3,000). This project involved installing a main line to loop the system and was in service December 28, 2000.
- Fry Township Water Mains ($21,310). This project involved the lowering and relocation of mains due to the installation of new sewer lines by the City, and was completed and in service November 30, 2001.
- Stump Canyon Water Main ($30,815). Replaced 1 inch ranch pipe with 4 inch C900 PVC. In service January 3, 2002.
- Miscellaneous projects ($44,094). These projects included replacing the motor at Well #19 due to failure, looping mains from 7th Street to Tacoma Street, upgrading computer equipment to run valve maps on in-house system, replacing a failed booster at the Vista View Booster station, upgrading a main along the County portion of SR 90, replacing a

failed pump and motor at Nicksville sell site #10 and purchasing hydrant meter for construction workers.

The Company believes it is appropriate to include this post-test year plant as it was installed to serve existing customers, is necessary for system reliability, is revenue neutral, and is used and useful sufficiently in advance of the hearing to allow Staff a reasonable opportunity to inspect the plant. All post-test year plant at issue here was in service no later than January 3, 2002, with the majority in service by October 23, 2001. Staff verified the plant was in service and received invoices supporting the cost. The Company argues that Staff and RUCO's refusal to consider the post-test year plant ignores the totality of the Commission's rules, the Commission's history of recognizing post-test year additions and the specific evidence presented in this case.

Bella Vista does not dispute the Commission's discretion to use an historic test year as long as the Commission does not abuse its discretion and does not refuse to consider all relevant evidence. Neither does Bella Vista dispute the Commission's discretion to exclude post-test year, or even test year plant, where the evidence indicates either (1) the plant is not needed to service existing customers or (2) material changes in revenues or expenses related to the plant creates a substantial mismatch between revenues, expenses and plant. However, Bella Vista argues, the use of the historic test year must not arbitrarily and illegally deprive Bella Vista of a fair return on the fair value of its plant devoted to public use. Under the approach taken by Staff and RUCO, plant placed in service December 31, 2000, would be recognized, while plant placed in service January 1, 2001 would not, and Bella Vista views this as "the epitome of arbitrariness" and "inherently discriminatory". The Company asserts that post-test year plant must be treated like any other pro forma adjustment. Bella Vista asserts any rate making is premised on the desire to forecast future conditions.

The Company complains that Staff and RUCO focus on A.A.C. R14-2-103(A)(3)(p) which defines the historic test year, but ignore the Commission's other filing requirements (A.A.C. R14-2-103(A)(3)(i), (h) and (n) which permit pro forma adjustments as well as requiring "projected" data. The Company argues that nothing in the rules requires greater reliance on the historic year than on projected data. In using its discretion, the Company argues, the Commission must give due consideration to all relevant factors. In this case, Bella Vista asserts, it made pro forma adjustments

to reflect known and definite changes and to ensure the test year provided a more realistic relationship between revenue, expenses and rate base at the time the rates would be effective.

The Company argues the evidence is uncontraverted that the Company does not have a rapidly growing customer base; that the plant was installed to service existing customers to increase system reliability; and that revenue levels and operating income of the Company decreased in 2001 over the test year. Based on these facts and its experience operating the system, the Company concluded that the operation of the additional plant would have no impact on revenues and no significant impact on operating costs. Neither Staff nor RUCO conducted any study of the impacts of the plant, but Staff's engineer testified that any impact of the new plant would be negligible.

The Company notes that the Commission has routinely included post-test year plant in rate base. In Bella Vista's prior rate case, both Staff and RUCO supported including post-test year plant and did not require the Company to quantify the plant's impact on revenues or expenses, as they now do. The Company claims it relied on the Commission's historic treatment of post-test year plant when it proceeded with an extensive capital improvement program funded with borrowed funds and in deciding the timing of its rate application. The Company claims that Staff's position is a radical departure from Commission precedent and should not be implemented on an ad hoc basis after the Company has financed $2.1 million of plant improvements and filed a rate application. The Company cites numerous examples of circumstances where the Commission approved post-test year plant.

The Company argues that Staff's and RUCO's positions in this case fly in the face of Arizona case law that confirms the use of the historic test year, but also the right to consider pro forma adjustments. See Arizona Corporation Commission v. Arizona Public Service Co., 113 Ariz. 368, 555 P.2d 326 (1976). In Ariz. Corp. Comm'n. v. A.P.S., the Court also stated that "[i]t appears to be in the public interest to have stability in the rate structure within the bounds of fairness and equity rather than a constant series of rate hearings." Bella Vista argues that Staff's and RUCO's suggestion that post-test year plant cannot be considered, results in an irrational and inequitable situation and that every regulated utility that adds revenue neutral plant for the benefit of existing ratepayers, will have to wait 19 to 24 months, or more, before earning any return on it.

RUCO's Position

RUCO opposed the inclusion of the post test year plant in rate base on the grounds that there are no extenuating circumstances that warrant violating the requirement of A.A.C. R14-2-103(B), which requires that rate applications be based on a historical test year. RUCO argues that the Commission traditionally relies on the historic test year to determine fair and reasonable rates and that fair and reasonable rates can only be determined if there is a matching of all ratemaking elements. The use of an historic test year guarantees a matching of all rate base and operating revenues. RUCO asserts that outside of special or unique circumstances, the Commission generally requires the following criteria be met to warrant inclusion of post test year plant in rate base:

1) the cost be known and measurable;

2) the test year revenues match the post-test year investment;

3) the test year expenses match the post-test year investment; and

4) the plant be used and useful.

RUCO argues that Bella Vista's post-test year addition would violate the second and third criteria because the effect the additions would have on operating expense levels are unknown. RUCO acknowledged that the Commission has allowed the inclusion of post test year plant in other cases, but argues that the reasons the Commission deviated from its general practice in those cases are not present in the current case. RUCO specifically cites the Far West Water Company case (Decision No. 62649) and Paradise Valley Water Company (Decision No. 60220). RUCO distinguishes these cases based on the fact that Bella Vista's post-test year plant additions are not the result of a Commission order, or to address water quality concerns and were not made as a result of an extraordinary event.

Staff's Position

Staff also opposed the inclusion of post-test year plant because to do so would violate the matching principle and not be in keeping with widely accepted rate making principles. Staff argues the impacts of the Company's proposed post-test year plant on revenues and expenses are not known and measurable. Staff asserts that Arizona is an historic test year state and that Commission rules (A.A.C. R14-2-103(A)(3)(p)) require the end of the test year to be the most recent practical date

available prior to filing. Staff states that while pro forma adjustments are allowed, when appropriate, the starting point for determining rate base, revenues and expenses is the test year that the Company chooses when it files its case. Staff states that pro forma adjustments are defined in A.A.C. R14-2-103(A)(3)(i) as "adjustments to actual test year results and balances to obtain a more normal relationship between revenues, expenses and rate base." A.A.C. R14-2-103(A)(3)(h) defines Original Cost Rate Base as the "depreciated original cost, prudently invested, of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used or useful, plus a proper allowance for working capital and including all applicable pro forma adjustments." Staff defines the issue in this case as whether the pro forma adjustments to rate base also includes known and measurable changes to revenues and expenses. In this case, Staff argues, the Company has failed to quantify the effects of post-test year plant on revenues and expenses and failed to apply the matching principle.

Staff testified that it is incorrect to assume that because plant additions do not provide service to new customers, the impact is revenue neutral. Staff stated that new plant may improve system reliability resulting in lower expenses and increased revenues. Further, Staff argues no extraordinary circumstances justify including the plant into rate base.

Staff argues it is the Company's burden to show that the post-test year plant will not add to revenues, not Staff's burden to show it would not. Staff believes the Company could not substantiate its claim the additions are revenue neutral because it is impossible to quantify the impacts this post-test year plant will have on revenues and expenses. Staff states that the Company's argument that the need for the plant to ameliorate vulnerability to drought conditions and the fact that curtailment on the Rail Oaks system was less severe in 2002 than in 2000 can have an impact on revenues. Further, Staff argues, the new plant could make the system more reliable and thus more attractive to growth which could impact revenue.

Staff argues that because the majority of plant was not in service until the latter half of 2001, there is no way to quantify the impacts on revenues or operating expense. Staff argues that because the Company could not quantify the impacts of the new plant on revenues and expense, and because the impacts are not known and measurable, it is improper to include the post-test year plant. Staff

argues that the Far West Water & Sewer Rate case, the Paradise Valley Water Company rate case and the Gold Canyon Sewer rate case, relied on by the Company as support for including post-test year plant, are distinguishable from the current case. Staff argues under Arizona case law, the Commission has discretion to consider pro forma adjustments and it may include those adjustments into rate base, but there is no requirement that it must include post-test year plant. See Consol. Water Util., Ltd v. Arizona Corp. Comm'n, 178 Ariz. 478, 483-84, 875 P.2d 137, 142-43 (App. 1994) and Litchfield Park Serv. Co. v. Arizona Corp. Comm'n, 178 Ariz. 431, 437-38, 874 P.2d 988, 994-95 (App. 1994).

Resolution

Court decisions have confirmed the Commission has broad authority to determine fair value. While this Commission utilizes the historic test year as a starting point, the rules permit, and in the past we have allowed, pro forma adjustments in order to more accurately reflect reality during the period the rates will be in effect. In Decision No. 62993 (November 3, 2000), in which the Commission considers its Water Task Force's Report, the Commission approved Staff's request to order Staff to develop a policy with specific requirements for expense changes, revenue changes, and plant additions that occur after the test year. At that time, in connection with its recommendations concerning a future test year, Staff stated:

> Staff believes there is no need to change the present method used by the Commission. At present, the Commission employs an historic test year but does allow for pro forma additions for known and measurable costs. It is Staff's opinion that this is a very good combination of both historic and future test years. Presently, this is done on a case-by-vase basis.

Staff thought the process could be improved and sought authorization to develop a policy that would include, but not be limited to :

a. Method of matching new expenses with new revenues.

b. Revenue neutral plant, i.e. plant to serve existing, not future customers.

c. Revenue neutral plant will be installed within a specific time frame, preferably one year.

d. Revenue neutral plant is necessary to provide proper and adequate service to existing customers.

Staff has not yet developed such policy. Until a comprehensive policy can be established and

approved by the Commission, we believe the current case-by-case analysis should be continued. In this case, all of the plant was installed within a year and three days of the end of the test year, with much of it earlier than that. Furthermore, the preponderance of evidence indicates there is no material mismatch between the plant investment, revenues and expenses.

No party argues that the post-test year plant in question was not necessary or was not used and useful at the time of the hearing. The Company presented evidence that the plant would not materially affect revenues and expenses. It recognized that the new plant must be maintained and the new wells and booster station will cause the Company to incur additional power costs and there will be additional testing costs associated with the new wells, but believed these costs should be somewhat offset by the nominal power savings associated with the improvements to the four booster stations at Well #18. The Company did not seek to adjust expenses associated with these costs. There was a suggestion that increased reliability to the Rail Oaks system which had experienced curtailments in the past, may increase revenues. We find this possibility insufficient to overcome either the evidence that the impact on revenues will be nominal or the burden that would result from excluding the plant. Staff's engineer testified he believed any impact on revenues and expenses would be nominal.

We believe that it is not in the public interest for Bella Vista to incur the expense associated with another rate case to begin earning a return on plant that is being dedicated to provide service to existing customers. We do not want to discourage companies like Bella Vista from proactively addressing system reliability needs. The Company relied on past Commission decisions that allowed post-test year plant in determining the timing of its rate application. We do not agree with Staff and RUCO that the Commission has always required extraordinary circumstances to allow post-test year plant. Until this Commission establishes a clear policy concerning post-test year plant, we do not believe it is fair to refuse to consider post-test year plant when the majority of evidence indicates that there will not be a material mismatch between revenues and expenses and the investment in the plant.[3]

[3] We concur with Staff that the Company has the burden to demonstrate that the post-test year plant is revenue neutral, but believe, based on the totality of evidence in this case, that the Company has met that burden.

Cash Working Capital

Company's Position

Bella Vista employed the formula method to calculate cash working capital. Bella Vista states it used this method in every prior rate case it has filed, and that it is a widely accepted method for calculating cash working capital. The Company argues that no rule, regulation or order precludes it from utilizing the formula method for calculating cash working capital. Bella Vista states that Staff provided no evidence whatsoever of the Company's cash working capital, and the Commission cannot ignore Bella Vista's evidence that cash working capital should be $143,846. RUCO also utilized the formula method for determining cash working capital (although recommending an allowance of $128,948 based on its recommended operating expenses).

Staff's Position

Staff argues that the Company, by using the formula method to calculate cash working capital, has not met its burden to justify cash working capital. Staff advocates that the Company should use a lead-lag study because such studies are more accurate methods of determining cash working capital. Lead lag studies measure the timing of actual transactions and cash flow. Staff criticized the formula method because it always results in a positive cash working capital, while a lead lag study could confirm that cash working capital should be zero or a negative number. Staff argues that the Company's argument that it is too expensive to perform a lead lag study is not sufficient justification to allow the proposed $143,846 in cash working capital.

Resolution

In this case, RUCO and the Company relied on the formula method to calculate cash working capital, while Staff argued that a lead lag study is required to meet the Company's burden to show that positive working capital is appropriate. The Company has historically relied on the formula method in past rate cases and argues a lead lag study is too expensive.

We concur with Staff that a lead lag study more accurately determines the need for a cash working capital allowance. The Company's formulaic calculation of cash working capital is the only evidence in this case, as no other party performed a lead lag study or provided other evidence of a different cash working capital need. We accept the Company's use of the formula method of

calculating cash working capital for the purposes of this case, however, in future rate filings, we will require Bella Vista to perform a lead lag study if it wants to include an allowance for cash working capital. As a Class B utility, any extra burden on the Company from performing such study is not unreasonable and is outweighed by the benefits of a more accurate method of determining cash working capital. We note that this requirement is consistent with past Decisions affecting Class B utilities. Thus, based on our approved operating expenses, we authorize a working capital allowance of $137,550.

Accumulated Depreciation

Company's Position

The Company accepts Staff's calculation of accumulated depreciation, but RUCO has not. RUCO used two different depreciation rates in calculating accumulated depreciation. RUCO applies the 5 percent composite depreciation rate for plant that used to be held by Nicksville Water Co. Bella Vista argues that RUCO's position must fail for two reasons: 1) as a result of the merger/consolidation approved in Decision No. 61730, Nicksville ceased to exist together with the depreciation rate approved for Nicksville; and 2) it is unreasonable for a party to accept a rate base and depreciation expense in a settlement utilizing one depreciation rate and then argue that a higher depreciation rate should be utilized for computing an accumulated depreciation in the next rate case.

RUCO's Position

RUCO did not brief this issue. In testimony RUCO states that Bella Vista's previous rate case, which was a settlement, makes no mention of new depreciation rates. RUCO states that pursuant to A.A.C. R14-2-102(C)(4) depreciation rates cannot be changed absent a Commission order authorizing such change.

Resolution

In Decision No. 61730, Bella Vista's last rate case, the Commission approved a settlement between the Company, RUCO and Staff. In that Decision, the Commission adopted the negotiated overall value for FVRB and did not rule on particular components of rate base. At that time the parties did not present evidence of their intent regarding depreciation rates. Although RUCO disputes that in approving the settlement agreement, the Commission adopted Staff's pre-settlement

plant values, it appears that the ultimately agreed-upon amount is consistent with Staff's position in the earlier case. It is reasonable to conclude, absent evidence to the contrary, that when the Commission approved the merger/consolidation that Nicksville, and its depreciation rates ceased to exist. Consequently, we adopt the Company's and Staff's position on this issue.

Rate Base Summary

Based on the foregoing, we adopt an Original Cost Rate Base ("OCRB") of $7,482,520, which includes $1,797,279 of post-test year plant, and a cash working capital allowance of $137,550. Because the Company presented no evidence of reconstruction cost new depreciation rate base, the OCRB is deemed the Fair Value Rate Base ("FVRB").

Income Statement Issues

Professional and Consulting Fees

Company's Position

Bella Vista includes $50,356 for professional and consulting fees in Operating Expenses. RUCO recommends $47,021 and Staff proposes $39,430. The Company contests RUCO's recommendation to disallow $1,487 in legal fees related to the critical habitat for the Laoch Minnow and the Leopard Frog, both endangered species, since monitoring these activities is necessary due to potential adverse impact on water resources. The Company also contests the disallowance of $27,600 for environmental studies at all the Company's wellsites and $9,898 for due diligence costs associated with the potential acquisition of three water companies for their production capabilities, since the environmental assessments will aid the Company in securing loans and dealing with ADEQ in the future, and the due diligence expense is similar to preliminary costs for locating a new well. The Company proposes to amortize these two costs over a three year period.

RUCO's Position

RUCO did not brief this issue, but stated that the fees it recommends be disallowed are related to the potential sale of Bella Vista.

Staff's Position

Staff recommends that $27,600 expended for an environmental review related to selling the Company's operations and $9,890 expended for a due diligence review of its system relating to

potential acquisition of three water companies should not be allowed. Staff argues that the environmental review was not related to providing water service and the due diligence review was not the result of its normal cost of doing business. Staff asserts that shareholders rather than ratepayers reaped the benefits of these expenditures. If the Company had not been seeking to sell operations or acquire other companies, it would not have commissioned either study.

Resolution

We concur with Staff. The Company did not incur these expenses for the benefit of ratepayers, and they are not on-going expenses. Consequently, we accept Staff's recommended $39,430 for Professional Fees.

Property Tax Calculation

Company's Position

All parties employ the Arizona Department of Revenue ("ADOR") methodology that utilizes three historic years of revenue to determine property taxes. The Company states that the only issue is what years to include in the formula. The Company states it advocates using 2000, 2001 and the revenues approved by this proceeding as the most accurate forecast of the future property tax expense. Bella Vista states that Staff utilizes 1999 and 2000 with its proposed revenues and RUCO uses years 1998, 1999 and 2000. Bella Vista calculated a Property Tax expense for the test year of $205,787. RUCO recommends $200,400, and Staff recommends $174,243 for the test year. Under its proposed rates, the Company calculates Property Tax Expense of $364,464, Staff calculates $172,311. (Under RUCO's methodology the Property Tax Expense does not change with proposed revenues.)

RUCO's and Staff's Positions

Neither RUCO nor Staff briefed this issue. In testimony, RUCO expressed the belief that the Company is incorrect when it used pro forma revenues as opposed to actual revenues for the 1998 through 2000 operating periods. Staff's witness, Mr. Igwe, states using only historical revenues to calculate property taxes causes a mismatch between the property taxes used in ratemaking and actual bills as the revenues generated by new rates become historical and incorporated into ADOR's calculation. Thus, Staff explains it uses two historic years and Staff's recommended revenues to

calculate the three-year average. Staff states this methodology provides a normalized amount for property taxes over several years. Staff states that the difference between its methodology and that of the Company is that the Company uses test year revenues twice as a substitute for the two historical years.[4]

Resolution

Staff used revenues for 1998, 1999 and 2000 for calculating the Property Tax Expense for the test year. We concur that this is a proper method for calculating property taxes, although using actual Property Taxes paid is reasonable too for the test year under current rates. Under proposed rates, the most logical approach is to use the two most recent historic years' revenues and the projected revenues under the newly approved rates. In this case, we utilize 2000, 2001 and the projected year.

Depreciation Expense

Company's Position

Bella Vista states the only issue is the inclusion of $41,395 associated with the post-test year plant. Our decision to include post test-year plant in rate base results in additional Depreciation Expense of $41,395.

Wages and Salaries

Company's Position

The Company had a vacant field position during the test year. Staff confirmed that it was filled and made the appropriate pro forma adjustment. The Company accepts Staff's adjustments. RUCO did not accept the adjustment and thus, the Company argues, understates wages, employee benefits and payroll taxes.

RUCO's Position

RUCO did not brief this issue. The Company had originally sought $187,636 for field labor. RUCO recommended removing $48,464 because the Company did not provide any analysis or study to support the need for three additional employees and was able to operate in the test year and into 2001 without them.

[4] Later, the Company revised its position and used the test year 2000 and actual 2001 revenues in its calculation.

Resolution

Staff reduced the Company's requested $187,636 for field labor by $32,760. Staff's adjustment allows the wages associated with the position of a water maintenance worker filled in 2001, and is based on the known and measurable costs going forward.

Because the Company filled the open position subsequent to the test year, Staff's adjustments to wages, benefits and payroll taxes are appropriate. This is a known and measurable expense and most accurately reflects actual costs.

Medical and Dental Insurance

Both Staff and RUCO made pro forma adjustments to medical and dental expenses. The Company accepted Staff's adjustment as more accurately reflecting the future expense. The Company had proposed a pro forma adjustment for increased medical and dental insurance costs consistent with its adjustment to field labor expense. Staff accepted one-third of the costs associated with three vacant positions to reflect the filling of one of the positions in 2001.

We concur that Staff's adjustments are known and measurable and best reflect reality.

Director's Fees

Company's Position

Bella Vista argues that RUCO arbitrarily reduced Director's Fees to $9,000, from $31,200, without conducting any analysis to support the reduction. The Company explains that its policy is to compensate directors $450 per month as a retainer for generally being available to respond to questions and monitor the activities of the Company on an ongoing basis. Additionally, each director receives $1,000 per day for attending director's meetings, plus out-of-pocket expenses. The directors live in three separate cities, one in California. The Company argues the Directors' Fee Expense is fair and reasonable and should be allowed.

RUCO's Position

RUCO did not brief this issue. In testimony, however, RUCO's witness expressed the belief that $9,000 was fair and reasonable for Director's Fees, which was based upon the $6,000 the Commission approved in the Company's 1992 rate case, plus an additional 50 percent.

Resolution

RUCO's method for determining the reasonable amount for Director's Fees does not address the reasonableness of the Company's position, and its sole reliance on an amount approved in 1992 is not sufficient for us to adopt its recommendation. Staff did not adjust Director's Fees Expense, believing the amount was not unreasonable. We find that $450 per month and $1,000 a day for attending meetings is fair and reasonable, and adopt the position taken by the Company and Staff.

Postal Increase

The United States Post Office raised postage rates during the pendancy of this case. No party initially recommended increasing postage expense due to the rate increase as testimony had been filed prior to the increase. At the hearing, no party contested the appropriateness of adjusting expenses to reflect the postal increase. The Company estimates the impact of the rate increase as increasing postal expense by $2,403.

Because postage is a necessary expense and the effect of the post-test year increase in postal rates is known and measurable, a pro forma adjustment to reflect the current rates is fair and reasonable.

Summary of Test Year Income

Test Year Revenues	$2,907,775
Staff's Recommended Test Year Expenses	$2,395,005
Plus:	
Depreciation post-test year plant	$ 41,395
Postal Rate Increase	$ 2,403
Adjusted Test Year Expenses	$2,438,803
Test Year Operating Income	$ 468,972

In the test year the Company experienced a 6.3 percent rate of return on FVRB.

Cost of Capital

Company's Position

Bella Vista proposed a return on its fair value rate base of 9.5 percent. The Company argues that its manager, Ms. Gignac, testified that based on practical experience of managing Bella Vista for

14 years and managing multi-million dollar budgets while a member of the Board of Regents and member of the Cochise County Board of Supervisors and her practical observations as an investor, the Company was entitled to a 10 percent return. The Company also presented the testimony of Ron Kozoman, who advocated a return of 9.5 percent which is based on a 10.5 percent return on equity and a capital structure that contains the additional plant and the $2.1 million WIFA loan associated with the plant.

Mr. Kozoman arrived at his recommendation after computing expected return using both the discounted cash flow method ("DCF") and the capital asset pricing model ("CAPM"), examining the comparable returns on equity for seven of the eight water companies followed by Value Line, evaluating the specific non-systematic risks faced by the Company and the appropriateness of providing an incentive return to recognize the good management practices of the Company. Bella Vista asserts the specific risks faced by the Company are inadequately encompassed by the systematic risk assumption contained in the portfolio theory propounded by Staff and RUCO, which include its small size, its static growth, the general adjudication of the San Pedro watershed, radon, Commission policies, drought and the San Pedro River Conservation Area. The Company argues that the 8.1 percent return proposed by Staff does not encourage further investment in the system and discourages investment in the system.

Bella Vista also takes issue with Staff's and RUCO's refusal to consider the 11.5 percent accounting rate of return of equity projected for the period 2004 through 2006 for the sample water utilities. The Company argues that the comparable earnings method has been an appropriate measure of fair return for more than 100 years and eliminates the subjective judgment required by the DCF and CAPM. In addition, the Company cautions the Commission about lowering returns to reflect the current poor economy. Within less than a year, the Company asserts, returns on equity have tumbled by more than a percent. The Company argues a utility represents a long-term investment in an enterprise vested with the public interest and it is critical that returns be set to avoid the wild swings experienced in the open market place.

Bella Vista argues the unreasonableness of Staff's return recommendation is magnified by the exclusion of one-third of the Company's rate base (i.e. post test year plant). Although arguing that

including post test year plant violates the matching principle, Bella Vista argues that Staff ignores the matching principle by recommending that the capital structure include the $2.1 million WIFA debt associated with the post test year plant. The Company argues the WIFA debt is distinguishable from other capital in that it is related to capital improvements and may be used solely for that purpose.

Bella Vista advocates a 0.5 to 1.0 percent incentive rate of return to recognize the above-average management of the Company. In addition to taking over the poorly managed and poorly maintained Nicksville and Hougland system and significantly upgrading the plant in service to these customers, Bella Vita argues its has been able to provide its high level of service with a lesser investment per customer in net plant than the national average. The Company argues that it has acted proactively by installing the post-test year plant to address water production difficulties, especially in times of drought, and has provided redundant production capacity by interconnecting portions of its system.

The Company argues the analyses performed by Staff and RUCO vacillate rapidly in a volatile stock market, while the Company's comparable earnings approach recognizes that utilities are perceived as stable investments by investors. The Company asserts its recommendation reflects a gradual reduction in the authorized return to reflect the current economic conditions, and that in contrast, Staff's and RUCO's proposals will subject Bella Vista and all other water utilities in the State, to wildly fluctuating and plummeting rates of return

RUCO's Position

RUCO recommends that the Commission approve a 9.66 percent rate of return on the Company's invested capital. RUCO's recommended weighted cost of capital is comprised of a 9.63 percent cost of long-term debt and a 9.66 percent cost of common equity. RUCO did not include the WIFA loan associated with the post-test year plant in its capital structure. RUCO's calculation of the weighted cost of capital is as follows:

	Amount	%	Cost	Weighted Cost
Long-term Debt	$ 596,525	9.18%	9.63%	0.88%
Common Equity	$5,902,436	90.82%	9.66%	8.77%
Total	$6,498,961	100.0		9.66%

RUCO derived its cost of equity based on the DCF and CAPM models. RUCO argues that the DCF is regarded in the industry as conceptually sound and the CAPM method is the best and most consistent of the various methods. RUCO's cost of capital witness, Mr. Rigsby, weighed the results of both the DCF and the CAPM. RUCO employed a proxy sample of companies that face the same types of risks as Bella Vista.

RUCO notes that Bella Vista had originally based its proposed cost of capital on the upwardly adjusted results of a DCF and CAPM analysis, but during the rebuttal phase of the proceeding, abandoned that methodology for a comparable earnings analysis, which produced a cost of common equity of 10.5%. RUCO argues that Bella Vista's own witness had testified in another proceeding that the comparable earnings analysis is based on circular logic, as the results are based on returns of utilities that were set by regulators as opposed to relying on forward looking information and taking analysts' projections into consideration.

Staff's Position

Staff recommends a regulatory rate of return of 8.1 percent based on a cost of equity of 9.1 percent and a cost of debt of 5.94 percent, using the Company's current capital structure.

Staff asserts that it is appropriate to include the WIFA debt as part of the Company's capital structure even though Staff does not recommend including the plant that was financed with the debt as part of rate base. Staff argues the matching principle does not apply to cost of capital analysis because cost of capital is a financial analysis looking at investors' present and future expectations and is not an accounting analysis that looks at the inclusion of post-test year plant. Investors make financial decisions based on present and future conditions. Staff asserts that if a Company's test year capital structure is significantly different than its actual going-forward capital structure, then it should not be used to calculate the company's cost of capital, regardless of rate base determination. Staff states its analysis utilizes an accurate snapshot of Bella Vista's capital structure. Staff recommends a capital structure containing 31.9 percent long-term debt and 68.1 percent common equity.

Staff asserts that it used sound financial models to determine a cost of equity, utilizing the DCF and CAPM models. Staff's witness, Mr. Reiker, used the constant-growth DCF analysis and the multi-stage non-constant growth DCF analysis, and conducted his analysis using eight publicly

traded water companies followed by Value Line. Mr. Reiker's analyses resulted in the following estimates: Constant Growth DCF, 9.1%; Multi-Stage DCF, 9.3%; Historical MRP CAPM, 9.4%; Current MRP CAPM, 9.3%; for an average of 9.3%.

As a result, Mr. Reiker determined a reasonable range for the cost of equity was between 9.1 and 9.4 percent. Then, based on accepted standard corporate finance theory, Mr. Reiker adjusted his results to estimate the effect Bella Vista's capital structure has on its cost of equity. Capital structure affects cost of equity because a greater percentage of debt results in a greater level of financial risk. Staff states the Bella Vista's capital structure contains a significantly lower ratio of debt than the sample companies, which lowers the Company's cost of equity. Therefore, he recommends that the cost of equity be set at the lower end of his reasonable range, or 9.1 percent.

Staff's calculation of its recommended weighted cost of capital is as follows:

	Weight	Cost	Weighted Cost
Long-term Debt	31.9%	5.94%	1.9%
Common Equity	68.1%	9.1%	6.2%
Cost of Capital			8.1%

Staff asserts the Company's recommended rate of return is based on faulty assumptions that lead to an inaccurate picture of the actual conditions affecting Bella Vista. The Company's inclusion of unique risks into the cost of equity fly in the face of established precepts on cost of equity, and Mr. Kozoman's reliance on accounting returns give a misleading picture of actual market returns and investor expectations. Staff argues the Commission should not adopt the Company's suggestion to add "basis points" to the cost of equity to reflect the unsystematic risks the Company argues it faces. Staff asserts that the DCF and CAPM models provide a real world analysis because unsystematic risk is not part of market risk and can be avoided by portfolio diversification. Staff also asserts that much of what the Company perceives as unique risks are really risks that all water companies face and are already reflected in the DCF and CAPM analysis.

Staff criticizes the Company's reliance on accounting returns, and argues that market return is the more accurate gauge of investor expectations because the shareholder is not directly interested in

the ratio of book earnings to book equity. Rather, Staff argues, the investor is interested in anticipated dividends and capital gains relative to the price he or she has to pay. Staff advocates that the Commission rely upon market-based models and not on accounting returns to determine the appropriate cost of equity in this case, especially in light of recent revelations concerning accounting practices for publicly traded companies.

Resolution

Our decision to include the post-test year plant in rate base warrants the inclusion of the WIFA debt. Thus, we adopt the Company's current capital structure, which consists of 31.9 percent long-term debt and 68.1 percent common equity.

The Commission typically has relied upon the DCF and CAPM models to calculate the cost of equity. The risk of operating a water company, including those Bella Vista claims are unique, are largely reflected in the market analysis. We find that making specific adjustment to the cost of equity as suggested by the Company, difficult to quantify and potentially arbitrary. Furthermore, the challenges this Company faces are born by all water utilities in some form.

RUCO's cost of equity analysis resulted in a range of 7.17 percent to 9.6 percent, with RUCO ultimately recommending a cost of equity of 9.66 percent. Staff's analysis resulted in a range of 9.1 percent to 9.4 percent and an ultimate recommendation of 9.1 percent. The Company's DCF and CAPM analysis, before Company-specific adjustments, resulted in a range of 6.33 percent to 10.83 percent, with an ultimate proposal of 10.5 percent.

We find that in this case that Staff's analysis and ultimate recommendation of a cost of equity of 9.1 percent is reasonable and fair. Thus, we approve a weighted cost of capital as follows:

	%	Cost	Weighted Cost
Long Term Debt	31.9%	5.94%	1.89%
Common Equity	68.1%	9.1%	6.19%
Total Capital	100.0%		8.08%

Revenue Requirement

Based on our approved FVRB of $7,482,520, and a weighted cost of capital of 8.08 percent, Bella Vista requires operating income of $604,588, and faces a revenue deficiency of $135,616. With our calculated revenue conversion factor of 1.7438, the required revenue increase is $237,837, an 8.18 percent increase over adjusted test year revenues. A summary of our findings follows:

Adjusted Rate Base	$ 7,482,520
Adjusted Operating Income	$ 468,972
Current Rate of Return	6.3%
Required Rate of Return	8.08%
Required Operating Income	$ 604,588
Operating Income Deficiency	$ 135,616
Gross Revenue conversion Factor	1.7538
Required Revenue Increase	$ 237,837
Adjusted Test Year Revenue	$ 2,907,775
Approved Annual Revenue	$ 3,145,612
Required Increase in Revenue (%)	8.18%

Rate Design

Both Staff and Bella Vista have retained the general rate design approved in the last rate case. The current rate design includes a three-tier commodity rate for 1 inch meters and smaller. RUCO proposed extending the third tier to all meters.

The Company's Position

The Company argues that RUCO did not perform a cost of service study or any analysis of the impacts of its proposal. Bella Vista states that in response to RUCO's proposal, it updated the cost of service study performed in the last rate case, which demonstrates that the larger meters are already paying well over their cost of service. RUCO's proposal would require these meters to further subsidize the cost of providing service to customers with 1-inch and smaller meters. The Company presented evidence that despite the current rate design, since 1997, water usage by customers with

meters of 1 inch or smaller increased, while usage by customers with larger meters decreased. Customers with meters larger than 1 inch are largely apartments, mobile home parks, multi-family dwellings and public schools, as well as a few commercial customers. Thus, the Company argued, RUCO's proposed design would not send the desired price signal directly to the ultimate water consumer. The Company argues the third tier is inappropriate and unnecessary for customers with meters larger than 1 inch.

RUCO's Position

RUCO did not brief this issue. In surrebuttal testimony, Mr. Rigsby stated that he believed RUCO's proposed rate design would constitute a meaningful attempt to encourage conservation by sending a price signal to all customers, not just those on smaller meters. RUCO believes the current design simply gives a break to selected customers.

Resolution

RUCO does not criticize the cost of service study. Absent evidence to the contrary, we accept the Company's proposed rate design that includes three tiers for meters 1-inch and smaller, and only two tiers for larger meters. The conservation message that RUCO would like to send by establishing three tiers for all meter sizes will not be passed on to the ultimate user with larger meters. Moreover, the cost of service study indicates that the larger users already bear more than their share of system costs. Without additional evidence on the effects of RUCO's proposed rate structure, we do not believe it is prudent to modify the current structure.

We cannot approve the specific rates the Company has proposed, as we are approving a different revenue requirement. We direct the Company to file a revised tariff based on its proposed rate design that produces total revenues of $3,145,612.

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. Bella Vista provides water utility services to approximately 6,659 residential and commercial customers in and around the City of Sierra Vista, in Cochise County, Arizona.

2. Bella Vista filed an application to increase its rates with the Commission on

September 28, 2001.

3. The Company filed an amendment to its application on October 16, 2001.

4. The Company used a test year of December 31, 2000.

5. The Commission authorized Bella Vista's current rates in Decision No. 61730 (June 4, 1999).

6. On October 29, 2001, Staff notified the Company that its application was sufficient and that it is classified as a Class B utility.

7. The Commission granted intervention to RUCO on December 4, 2002.

8. By Procedural Order dated November 4, 2001, the Hearing Division established procedural guidelines for the conduct of the proceeding and set the matter for hearing to commence July 25, 2002, in Tucson, Arizona. Pursuant to the procedural schedule, Staff and RUCO filed direct testimony on April 29, 2002. Bella Vista filed rebuttal testimony on May 28, 2002. Staff and RUCO filed surrebuttal testimony on June 18, 2002. Bella Vista filed rejoinder testimony on July 9, 2002.

9. On December 20, 2001, the Company mailed notice of the hearing to its customers. The Commission has not received any public comments concerning this application.

10. The hearing convened as scheduled on July 25, 2002 and continued on July 26, 2002 and August 16, 2002. Ms. Judith Gignac, the Company's general manger, and consultants Messers. Ron Kozoman, CPA, and Ken Bourassa, CPA, testified for the Company. Ms. Marylee Diaz-Cortez and Mr. William Rigsby testified for RUCO; and Messers. Alexander Igwe, Lyndon Hammond and Joel Reiker, testified for Staff.

11. Staff, RUCO and the Company filed briefs on September 9, 12 and 13, 2002, respectively.

12. The Company's FVRB is determined to be $7,482,520.

13. In the test year, the Company had total revenues of $2,907,775, adjusted operating expenses of $2,438,803, which resulted in adjusted operating income of $468,972, a 6.3 percent rate of return.

14. It is reasonable to include post-test year plant in the amount of $1,797,279 in adjusted rate base as this plant was in service no later than January 3, 2002 (which much of it in service during

the third quarter of 2001), was installed to benefit existing customers, and does not violate the matching principle of rate making as it will not materially affect revenues or expenses.

15. A weighted cost of capital equal to 8.08 percent is reasonable.

16. Based on an our approved FVRB and rate of return, the Company requires operating income of $604,588. Thus, the Company has an operating revenue deficiency of $135,616, and based on a gross revenue conversion factor of 1.7538 should be allowed a revenue increase of $237,837.

17. Bella Vista's current rate design structure is fair and reasonable. Bella Vista should file a revised tariff based on its current rate design, that produces annual revenues of $3.145,612.

18. Bella Vista is current on its property and sales taxes.

19. Bella Vista is in compliance with Arizona Department of Environmental Quality ("ADEQ") regulations and is providing water that meets the quality standards of the Safe Drinking Water Act.

CONCLUSIONS OF LAW

1. Bella Vista is a public service corporation within the meaning of Article XV of the Arizona constitution and A.R.S. §§ 40-250, 40-251 and 40-252.

2. The Commission has jurisdiction over Bella Vista and of the subject matter of the application.

3. Notice of the application was given in accordance with the law.

4. Bella Vista's proposed rates and charges are not reasonable. The rates and charges adopted herein are fair and reasonable.

5. The Company's proposed rate design is fair and reasonable and should be approved.

ORDER

IT IS THEREFORE ORDERED that Bella Vista Water Company, Inc. shall file on or before October 31, 2002, a revised tariff, based on its proposed rate design, that produces the revenue requirement approved herein.

IT IS FURTHER ORDERED that the new rates and charges shall be effective for all service provided on and after November 1, 2002.

IT IS FURTHER ORDERED that within 30 days of the effective date of this Order, Bella Vista Water Company, Inc. shall notify its customers of the rates and charges authorized herein and the effective date of same.

IT IS FURTHER ORDERED that Bella Vista Water Company, Inc. shall provide Staff a copy of the notice that it sends to customers within 60 days of the effective date of this Order.

IT IS FURTHER ORDERED that in its next rate case, Bella Vista Water Company, Inc. shall perform a lead lag study if it wants the Commission to consider a allowance for cash working capital.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Secretary of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 1st day of November, 2002.

BRIAN C. McNEIL
EXECUTIVE SECRETARY

DISSENT: _____

JR:mlj

SERVICE LIST FOR: BELLA VISTA WATER COMPANY

DOCKET NO. W-02465A-01-0776

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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
OCT 0 5 2004
DOCKETED BY NR

EXHIBIT S-4 ADMITTED

COMMISSIONERS

MARC SPITZER, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF RIO RICO UTILITIES INC. FOR PERMANENT INCREASES FOR WATER AND WASTEWATER UTILITY SERVICE.

DOCKET NO. WS-02676A-03-0434

DECISION NO. 67279

OPINION AND ORDER

DATE OF HEARING:	June 3 and 4, 2004
PLACE OF HEARING:	Tucson, Arizona
DATE OF PUBLIC COMMENT:	September 21, 2004
PLACE OF PUBLIC COMMENT	Rio Rico, Arizona
ADMINISTRATIVE LAW JUDGE:	Jane L. Rodda
IN ATTENDANCE:	Marc Spitzer, William Mundell
APPEARANCES:	Mr. Jay Shapiro, Fennemore Craig, on behalf of Rio Rico Utilities Inc.; Mr. Daniel Pozefsky, Attorney for the Residential Utility Consumer Office; and Mr. David Ronald, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

Rio Rico Utilities Inc. ("Rio Rico" or "Company") provides utility service to approximately 4,200 water and 1,500 wastewater customers in the community of Rio Rico in Santa Cruz County, Arizona.

On June 25, 2003, Rio Rico filed an application with the Arizona Corporation Commission ("Commission") to raise the rates for both water and wastewater service. On July 25, 2003, the Commission's Utilities Division Staff ("Staff") notified the Company that its application was not sufficient under A.A.C. R14-2-103. On August 4, 2003, Rio Rico provided additional information in

response to Staff's list of deficiencies. On September 11, 2003, Staff notified the Company that its application was sufficient, and classified the Company as a Class B utility.

On September 26, 2003, the Commission granted the request of the Residential Utility Consumer Office ("RUCO") to intervene.

By Procedural Order dated September 18, 2003, the matter was set for hearing and governing procedures set. Pursuant to the September 18, 2003 Procedural Order, Staff and RUCO filed Direct testimony and schedules on March 11, 2004; the Company filed Rebuttal testimony on April 15, 2004; Staff and RUCO filed Surrebuttal testimony on May 6, 2004; and the Company filed Rejoinder testimony on May 27, 2004. The hearing convened as scheduled in Tucson, Arizona on June 3, 2004.

On December 16, 2003, Rio Rico filed an affidavit that indicates it mailed notice of the hearing as required by the September 18, 2003 Procedural Order, to its customers on October 10, and October 28, 2003.

Ron Kozoman, a CPA and consultant, testified on behalf of the Company. Rodney Moore and William Rigsby testified on behalf of RUCO. Dennis Rogers, Joel Reiker and Lyndon Hammon provided testimony on behalf of Staff.

The Commission approved Rio Rico's current rates and charges in Decision No. 59547 (March 13, 1996).

According to the Company's schedules, in the test year ended December 31, 2002, the Company's water division saw Total Revenues of $1,084,065, yielding Operating Income of $31,354, for a 1.27 percent rate of return on an adjusted Original Cost Rate Base ("OCRB") of $2,463,948. Kozoman Rej (A-3) Schedule A-1. According to the Company, its wastewater division reported Total Test Year Revenues of $606,152, resulting in an adjusted operating loss of $105,248. Kozoman Rej (Ex A-3) Schedule A-1.

Rio Rico is requesting a revenue increase of $362,223, or 33 percent over Test Year water revenues, and a $869,199 increase, or 143.38 percent, over Test Year wastewater revenues. Kozoman Rej Ex. A-3 at 1. The Company's proposed rates would result in Operating Income for the water division of $246,395, for a 10 percent rate of return on adjusted OCRB of $2,463,948, and wastewater Operating Income of $413,668, a 10 percent rate of return on an adjusted OCRB of

$4,136,931. A-3 at Schedule A-1. Due to the magnitude of the increase necessary for the wastewater service, the Company is requesting a three-year phase-in for wastewater rates. Ex A-3 at 34.

RUCO determined that in the test year, Rio Rico experienced Operating Income of $62,928 in its water division, and an adjusted Operating Loss of $92,845 in its wastewater division. Moore Surrebuttal, Ex R-2, Schedule RLM-1. RUCO recommends a rate increase of no more than $163,299 for the water division, producing Operating Income of $165,999, for an 8.83 percent rate of return on an adjusted rate base of $1,879,947. Id. In the wastewater division, RUCO recommends an increase of $702,351, to produce Operating Income of $339,407, an 8.83 percent rate of return on an adjusted rate base of $3,843,790. Id.

For the water division, Staff recommends a $201,528, or 18.59 percent, revenue increase from $1,084,065 to $1,285,592. Rogers Dir, (S-1), Schedule DRR-1. Staff's recommended water revenue would produce operating income of $151,397 for an 8.0 percent rate of return on an adjusted OCRB of $1,892,466. Id. For the wastewater division, Staff recommends a $677,616, or 111.93 percent, revenue increase from $605,375 to $1,282,991. Id. Staff's recommended revenue would produce an operating income of $307,843, for an 8.0 percent rate of return on an adjusted OCRB of $3,848,036. Id.

All parties to the proceeding agree that Rio Rico is entitled to a rate increase for both its water and wastewater services. All parties agree that Rio Rico's actual capital structure, which consists of 100 percent equity should be utilized for ratemaking purposes. All parties agree with the rate design for the wastewater division. Staff and RUCO disagree with the Company about whether plant that was installed after the Test Year, but which was in service prior to the hearing, and which serve Test Year customers should be included in rate base. In addition, the parties disagree as to the cost of equity and the appropriate rate design for the water division. RUCO further disagrees with the Company's and Staff's calculation of Property Tax Expense and Income Tax Expense.

Post Test Year Plant

Position of the Parties

The Company proposes fair value rate bases based on an original cost equal to $2,462,446 for water utility plant and $4,136,931 for wastewater utility plant. See Kozoman Rebuttal (Ex A-2) at

Rebuttal Schedule One. These amounts include adjustments for post test year plant additions totaling $595,657 of water utility plant and $293,417 of wastewater utility plant. Kozoman Rejoinder (Ex. A-3) at 2. Rio Rico argues that its pro forma adjustments to rate base are appropriate and comply with Commission rules that allow pro forma adjustments "to obtain a normal or more realistic relationship between revenues, expenses and rate base." A.C.C. R14-2-103 (A)(3)(i).

In support of its request, Rio Rico cites a number of previous Commission Decisions where the Commission has allowed post test year plant. See *Arizona Water Company*, Decision No. 66849 (March 22, 2004) and Decision No. 64282 (December 28, 2002); *Bella Vista Water Company*, Decision No. 65350 (November 1, 2002); *Paradise Valley Water Company*, Decision No. 61831 (July 20, 1999); and *Far West Water Company*, Decision No. 60437 (September 29, 1997). Rio Rico states that in each of these decisions, the Commission included post test year plant additions in rate base after concluding that the plant additions were revenue neutral, used and useful, in service in sufficient time to allow other parties to inspect and audit the plant, and the amount to be included in rate base was known and measurable.

Rio Rico argues that there is no dispute in the instant case that all of the post test year additions were completed and placed in service before December 31, 2003, approximately three months before Staff and RUCO filed their direct testimony. Nor is there dispute that the requested post test year additions are based upon the actual cost of constructing plant. Rio Rico asserts that all of the post test year additions are revenue-neutral in that they serve customers existing at the end of the test year and not installed to serve future growth. Further, the Company states no party contends the additions are not used or useful. See Rio Rico Brief at 5.

The Company claims Staff did not provide support for its claim that including post test year plant in rate base is only appropriate where "extraordinary circumstances" are present. According to Rio Rico, no prior Commission Decision cites lack of "extraordinary circumstances" as the reason to reject the inclusion of post test year plant. Similarly, Rio Rico asserts that the Commission has rejected the argument in the past that post test year additions violate the "matching principle." Rio Rico argues that the Commission's rules clearly allow for pro forma adjustments, and improper mismatches are avoided by matching plant to test year customers and treating such plant as if it were

in service during the test year.

Further, Rio Rico argues that the opposition to inclusion of the post test year plant is undermined by the parties' acceptance of the Company's retirement of the existing force main, which was replaced after the test year. Both Staff and RUCO adjusted rate base to remove the retired force main. Rio Rico believes it is "absurd" to oppose the inclusion of post-test year plant in rate base while removing the plant that was replaced, post-test year, from rate base. Rio Rico Brief at 6.

Neither Staff nor RUCO believe that the post test year plant should be included in rate base. Both argue the inclusion of post test year plant violates the matching principle, where rate base, revenue and expenses are calculated at the same point in time. RUCO argues that the claim that post test year plant is revenue neutral does not ensure there are no mismatches in the ratemaking process because the installation of new plant affects expense items such as repairs and maintenance, insurance, overhead, purchased power, transportation, vehicles, etc. RUCO claims the only way to ensure proper matching is to adhere to a historical test year model. In this case, Staff asserts, the impacts of Rio Rico's post test year plant on revenues and expenses are not known and measurable. Even though the plant may be used to service existing customers rather than new customers, it may affect operating income by enhancing system reliability which could lead to lower expenses and increased revenues.

Staff explains that in general it only recommends allowing post test year plant in rate base when there are extraordinary circumstances. In this case, Staff does not believe that Rio Rico has demonstrated "extraordinary circumstances" that would make the inclusion of post test year plant acceptable. Staff distinguishes cases cited by the Company where the Commission has allowed the inclusion of post test year plant. Staff asserts that in the *Bella Vista Water Company* case, Decision No. 65350 (November 1, 2002), the Commission emphasized that the post test year plant would address system reliability and drought conditions. Staff distinguishes the *Arizona-American Water Company, Inc.* case, Decision No. 67093 (June 30, 2004), in which the Commission allowed the inclusion of post test year plant, as a unique circumstance where Arizona-American acquired the Citizens Communications Company water and wastewater systems the same year it filed the rate case and the post test year plant improvements were related to security needs following the events of 9/11.

Resolution

The Arizona Administrative Code R14-2-103.A.3.h provides that "original cost rate base" should include all "applicable pro forma adjustments." "Pro forma Adjustments" are "adjustments to actual test year results and balances to obtain a normal or more realistic relationship between revenues, expenses and rate base." A.A.C. 414-2-103.A.3.i.

The Commission considers whether the inclusion of post test year plant is appropriate on a case-by-case basis. In the past, the Commission has allowed the inclusion of post test year plant in circumstances where the new plant is revenue neutral and there is no evidence of a material mismatch between revenue and expenses and where the post test year plant is required for system reliability or to provide adequate service.

In *Arizona Water Company*, Decision No. 66849, the Commission found that "[b]ased on Commission precedent, including Arizona Water's Northern Group rate case (Decision No. 64282), Staff agrees that post-test year plant additions for up to one year may be included in rate base." Decision No. 66849 at p 3. In Decision No. 66849, the hearing and the time clock were extended to enable Staff and RUCO the opportunity to analyze Arizona Water's post-test year plant additions. Id. In the *Arizona Water Northern Group* case, Decision No. 64282, the Commission adopted Staff's proposal to include plant additions for up to twelve months following the end of the test year (the company in that case had sought additions that were placed in service up to 15 months after the end of the test year). Decision No. 64282 pp 3-5.

In the *Paradise Valley Water Company* case, Decision No. 61831, the test year ended June 30, 1998, but the company was seeking post test year plant in service through March 31, 1999. The Commission adopted the Staff and Company agreed-upon level of post-test year plant additions, but it expressed concerns about the ability of parties to review and audit the effects of post test year plant, and ordered that in its next rate case, the Company should limit its adjustments to add post test year plant to include only that plant that is used and useful and in service within 90 days of the date that the rate application is deemed sufficient. Decision No. 61831 pp 3-4.

In the *Bella Vista Water Company* case, Decision No. 65350, the Commission allowed the inclusion of post test year plant that was installed within a year and three days of the end of the test

year. In that case, the Commission found that "the preponderance of evidence indicates there is no material mismatch between the plant investment, revenues and expenses." Decision No. 65350 at p 11.

It is clear that Commission rules contemplate that there are circumstances where pro forma adjustments to allow for plant placed in service post test year to be included in rate base. In this case, the post test year plant in question was in service by October 2003 when Staff inspected the facilities. TR p 264. The new wastewater plant totaling $313,658 was the replacement for the Lift Station No. 2 force main. This replacement was not an "upsize" and was required because the Company had been experiencing breakages and spills with the old force main.[1] TR pp 261-263. The water division post test year plant constituted a 12 inch main and new booster plant totaling $587,169. The Company had been experiencing customer complaints of low pressure. TR p. 263. The preponderance of evidence indicates that the post test year plant that the Company seeks to include in rate base was installed to serve existing test year customers, was required for system reliability and that there would not be a material impact on revenue or expenses. In this case, it is fair and reasonable to include the post test year plant in rate base.

Property Tax Expense

Positions of the Parties

Rio Rico and Staff agree that Property Tax Expense should be determined based on proposed revenue increases within the Arizona Department of Revenue ("ADOR") formula. RUCO advocates using only historical revenue levels.

Rio Rico argues that the Commission has repeatedly utilized the proposed revenue increase to determine the appropriate level of Property Tax Expense. See *Arizona Water Company*, Decision No. 64282 (December 28, 2001) at 12-13; Decision No. 65350 (November 1, 2002) at 16; and *Arizona-American Water Company*, Decision No. 67093 (June 30, 2004) at 9-10. The Company argues that since the Commission is setting rates on a going-forward basis, it does not make sense to use the historic years 2000, 2001 and 2002, as proposed by RUCO, as ADOR will never again use those

[1] The Company had adjusted rate base to reflect the retirement of the force main which was retired after the end of the test year. Both Staff and RUCO removed the retried force main from rate base. Moore Direct (RUCO-1) at RLM 3, page 9 of 9; Rogers Dir. (Ex S-1) at DDR-4, line 11.

years to determine Rio Rico's property tax. Because it ignores the revenue increase approved herein, if RUCO's calculation of the Property Tax Expense is utilized, Rio Rico argues that it will not collect sufficient revenue to pay its entire property tax assessment during the period the new rates will be in effect.

RUCO claims that Rio Rico and Staff have varied the ADOR formula by using, for valuation purposes, two years of adjusted revenues plus one year of proposed revenues. RUCO based its calculation, which is based on the ADOR formula that multiplies the average of the three previous years of reported gross revenues times two. RUCO argues that the result of using the projected revenues is an inflated Fair Value Cash Value which increases the risk the Company will over-earn. RUCO states that because future revenues are unknown, future property taxes can only be estimated. RUCO believes the reasonableness of its method of property tax calculation is shown by the close correlation of its calculations with the actual 2003 Property Taxes paid.

Further, RUCO argues, Property Taxes, unlike Income Taxes, do not impact revenues immediately. In this case, assuming new rates go into effect by the end of 2004, it will not be until the end of 2005 that the Company will have one full year of operating revenues at the new rates. The Company will pay Property Taxes for the tax-year 2005 semi-annually, the first payment becoming due in October 2006, and the final payment due in March 2007. RUCO asserts the lag between the revenue projections and the actual payment of property taxes is so great that the projections become meaningless.

Resolution

We believe that the Company and Staff's calculation for Property Tax Expense yields the best estimate of the Property Tax expense for the period in which the new rates will be in effect. RUCO's use of only historic revenue does not take account of the effect of the rate increase and can result in an understatement of the Property Tax Expense. Our determination in this case is consistent with our findings in the recent *Arizona-American Water Company* rate case, Decision No. 67093 at 10 (June 30, 2004). We note that although we are not utilizing the exact ADOR formula for calculating Property Taxes, we are not calculating the Company's Property Taxes to send them a tax bill, but rather are determining the proper amount of Property Tax Expense for rate making purposes.

Income Tax Expense

Positions of the Parties

Rio Rico and Staff determined the appropriate level of Income Tax Expense by treating the Company as a single entity for income tax purposes. Kozoman Reb, Ex A-2 at 14. RUCO treats Rio Rico's water and wastewater divisions as if they are stand-alone entities for the calculation of Income Tax Expense. Moore Dir (Ex R-1) at 26.

Rio Rico argues that even though Rio Rico is owned by a holding company, Avatar Holdings, which pays income taxes on a company-wide consolidated basis, its revenue from its utility operations has tax consequences which will be calculated using consolidated, not stand-alone tax rates. According to Rio Rico, RUCO's methodology artificially lowers Rio Rico's Income Tax Expense and reduces each division's revenue requirement. The Company explains that income tax rates are 15 percent for the first $50,000 of taxable income, 25 percent for taxable income from $50,001 to $75,000, 34 percent for taxable income from $75,001 to $100,000, 39 percent for taxable income from $100,000 to $335,000, and 34 percent for taxable income over $335,001. Kozoman Rb (Ex A-2) at 14. Rio Rico states that RUCO's calculation double counts for the first $100,000 of taxable income by treating the Company as stand-alone water and wastewater entities, even though the Company's taxes are filed on a consolidated basis.

RUCO recommends that the Commission calculate Income Tax Expense on a stand-alone basis for each division. RUCO asserts that neither its proposed, nor the method used by Staff and the Company, reflect the way taxes are actually paid, since in reality, it is the parent company that pays taxes on a consolidated basis based on the revenues of all of its subsidiaries. RUCO states that the Commission traditionally allows for the treatment of income tax expense on a stand-alone basis. RUCO argues that other than the fact that it would provide for a greater income tax expense, neither the Company nor Staff has presented a good reason why the Commission should deviate from its normal practice.

Resolution

Historically, the Commission has calculated Income Tax Expense based on a stand-alone basis. Under this approach utility subsidiaries of a parent company are allowed to collect in rates

amounts for income taxes that result from the operations of the utility. In this case, the water and wastewater divisions are not separate subsidiaries. Staff and the Company have utilized a logical and reasonable methodology by calculating income taxes for Rio Rico as a single entity. Consequently, we adopt the methodology utilized by Staff and the Company.

Insurance Expense

Position of the Parties

Rio Rico proposed certain pro forma adjustments to insurance expenses that, on the whole, lowered the Company's revenue requirement. The cost of insurance, including property and general liability insurance, is paid by the Company's parent. After filing its rate application, the Company proposed adjustments to insurance expense to reflect a different allocation methodology that resulted in a decreased insurance expense since the test year. Staff agreed with the Company's adjustment.

RUCO did not adopt the Company's and Staff's pro forma adjustment because it stated there was no evidence that the new insurance expense allocation methodology has been implemented. The Company explained that the Company's parent made a mistake and delayed reflecting this adjustment in Rio Rico's books and records.

Nevertheless, Rio Rico states the Company has been paying the adjusted insurance expense allocation and this amount is now properly reflected in the books and records.

Resolution

RUCO did not address this issue in its Closing Brief. In any event, the evidence shows that the Company's pro forma adjustment to insurance expense, as adopted by Staff, is a correct reflection of insurance expense going forward, and should be adopted.

Summary of Revenue and Expenses

Based on the record and as determined herein, in its water division, Rio Rico earned adjusted revenues of $1,084,065. With adjusted Operating Expenses of $1,052,711, it produced Operating Income of $31,354 for the water division in the test year.

Its wastewater division collected adjusted test year revenues of $606,152. With adjusted Operating Expenses of $711,400, it had an Operating Loss of $105,248 in the test year.

Cost of Capital

Position of the Parties

The Company has a capital structure composed of 100 percent equity. The Company proposes a cost of capital of 10.0 percent based on the actual, authorized and projected returns on equity of substantially larger publicly traded water utilities and cost of equity estimates produced by the discounted cash flow ("DCF") model. Rio Rico Brief at 11. Kozoman Rejoinder (A-3) at 12. Rio Rico asserts that its recommended return is well supported by recent projections from *Value Line* (April 30, 2004) for the water utility industry which are 9.5 percent for 2005 and 10 percent for 2007-2009. Kozoman Rej (A-3) at 12. Similarly, Rio Rico states, current interest rates on treasury notes and investment grade bonds have increased and are forecasted to increase. (A-4) and (A-5). The Company also claims that while Rio Rico has less financial risk than the publicly traded utilities due to the lack of debt, it has more business and regulatory risk due to its small size, limited revenue and cash flow, small customer base, lack of diversification, and lack of liquidity because its stock is not publicly traded and cannot be sold easily. Kozoman Rej (A-3) at 13. Rio Rico asserts that as a small business, the risks associated with an equity investment in Rio Rico is greater than an investment in the sample of publicly traded water companies. Kozoman Reb (A-2) at 49-58; Kozoman Rejoinder (A-3) at 30-35.

Rio Rico claims the cost of equity recommended by Staff and RUCO are extremely low and patently unreasonable. Staff's witness testified that he was aware of only one other authorized rate of return, by this or from other jurisdictions, lower than Staff's proposed 8 percent (West Virginia-American Water Company was authorized a 7.0 percent return on equity). TR at 222-23; Kozoman Rejoinder (A-3) at 16. Rio Rico believes that the Staff and RUCO recommendations fail to take into account all of the business and regulatory risks Rio Rico faces in operating a small water and wastewater utility in southern Arizona, including revenue erosion or the ability of the Company to pay dividends. TR 253, 243-245. Rio Rico believes it is not realistic to consider only financial risk as Staff and RUCO have done.

Staff recommends an 8.0 percent weighted cost of capital. Reiker Sur (S-6) at 2. Staff relied on two market-based models—the DCF and the Capital Asset Pricing Model ("CAPM"). Staff

applied the DCF and CAPM to six publicly traded water utilities. Reiker Sur (S-6) at 29. Staff's analysis produced a cost of equity of 9.0 percent using the DCF method and 8.2 percent under the CAPM. The average of these methods is 8.6 percent. However, based on Rio Rico's capital structure, which includes no debt, Staff recommends a cost of equity of 8.0 percent. Reiker Sur (S-6) at 2. Because Rio Rico has no debt, Staff argued that its investors bear no financial risk and thus its cost of equity is significantly lower that the cost of equity of the sample water utilities which had an average debt/equity ratio of 50 percent. Reiker Dir. (S-5) at 25.

Rio Rico criticizes the CAPM method as becoming distorted when interest rates are abnormally low. Kozoman Reb (A-2) at 47. Staff claims that this argument suggests that the markets are in a "state of dis-equilibrium" which Staff believes is very unlikely and not consistent with the concept of a reasonable efficient market. Reiker Sur (S-6) at 2.

Staff criticizes the Company's reliance solely on the comparative earnings method to determine its weighted cost of capital. Mr. Rieker testified that the comparative earnings method is the practice of examining the previously authorized, actual and forecasted book/accounting earnings. Because the cost of equity is a market return, it cannot be observed by examining the book/accounting returns and authorized return on equity of other companies in Arizona. Reiker Dir. (S-5) at 26-32.

Staff states that the cost of equity depends only on the market risk of an investment and not the numerous firm-specific or unique risks associated with a firm. Staff claims the only type of risk that affects investors' required return is market risk, which is the risk related to economy-wide factors affecting all stocks. Reiker Dir (S-5) at 33. Staff argued that firm-specific risks affect the cash flow of the firm and the price investors are willing to pay for its stock, but do not affect the rate at which investors discount the expected future cash flows of a firm. Reiker Dir. (S-5) at 37. Staff notes that although firm-specific risks may be of interest to investors, these risks can be diversified away at no cost to the investor. Thus, Staff argues investors should not receive returns for unnecessarily choosing to take firm-specific risks.

RUCO recommends a weighted cost of capital of 8.83 percent. RUCO believes this rate is appropriate given the current environment of low inflation and low interest rates. RUCO's DCF

analysis yielded a cost of 9.04 percent, while its CAPM analysis resulted in a range of 7.25 percent to 8.62 percent. Mr. Rigsby averaged his DCF results with the high end of the CAPM range to derive his recommended cost of 8.83 percent. Rigsby Dir (R-3) at 27. RUCO believes its recommended return is reasonable when the Company's equity-heavy capital structure is taken into consideration and when RUCO's discounted cash flow growth rate estimates are compared with the growth estimates of other independent analysts. (R-3) at 17-21, Schedule WAR-5, 6.

Resolution

The DCF and CAPM are respected, sound and oft relied upon models for determining a firm's cost of equity. We believe that the analyses performed by Staff and RUCO relying upon these models are comprehensive and produce reasonable estimates of Rio Rico's cost of equity. Based on the entirety of the record, we find that Rio Rico's cost of equity to be 8.7 percent which is approximately the midpoint between Staff's updated estimate (8.6 percent) and RUCO's recommendation (8.83 percent). However, the Company's capital structure is comprised entirely of equity, at a time when the cost of debt is low. As a result, ratepayers are penalized by the Company's choice of a capital structure consisting entirely of higher cost equity. Although we are not using a hypothetical capital structure in this case, we believe that recognition of this imbalance should be reflected in the authorized rates of return for the wastewater division, which experienced an operating loss during the test year. We note that the 8.7 cost of equity we adopt is on the high side of the range of estimates, however, we believe it is fair and reasonable considering all of the circumstances in this case, including the need to implement the wastewater revenue increase in steps as recognized by the Company.

Revenue Requirement

Water Division

For the water division, the adjusted test year operating income is $31,354. The 8.7 percent of cost of capital translates into an 8.7 percent fair value rate of return on FVRB of $2,462,446 as authorized herein. Multiplying the 8.7 percent rate of return by FVRB produces required operating income of $214,232. Multiplying the deficiency by the gross revenue conversion factor of 1.68448 results in an increase in revenues of $308,081. This yields a Total Revenue Requirement of

$1,392,145, or a 28.4 percent increase over test year water revenues.

Wastewater Division

For its wastewater division, the Company's adjusted OCRB, which is the same as its FVRB is $4,136,931.

With adjusted test year revenues of $606,152 for its wastewater operations, the Company experienced an operating loss of $105,248.

Under the circumstances present here--a significant test year operating loss, a substantial increase in rate base, a capital structure with 100 percent equity, and a large required revenue increase, the rate of return authorized for the wastewater division, in order to be reasonable and appropriate, should reflect those circumstances. Pursuant to our discussion concerning rate design for the wastewater division, the equities warrant approving rates of return that increase over three years, with corresponding increases in the wastewater rates.

Thus, in the first year, we approve a revenue level of $905,727, an increase of $299,575, or 49.2 percent over test year revenues, which will yield Operating Income of $80,816, and a 1.95 percent rate of return on FVRB. In the second year, we authorize Operating Revenue of $1,205,302, an increase of $299,575, or 33 percent over the first year revenues, to produce Operating Income of $266,880, a 6.45 percent rate of return on FVRB. In the third year, the rates we would otherwise approve herein would lead to a revenue requirement of $1,355,089, an increase of $149,787, or 12.4 percent over the second year revenues, which will yield Operating Income of $359,912, and an 8.7 percent rate of return on FVRB. However, to further offset the impact of increased rates on its customers, Rio Rico has agreed to a reduction in the revenue increase that would otherwise result from our order such that the total increase we approve herein is $700,103, or 115.41 percent higher than test year revenues when the rates are in place in the third year for a total revenue requirement of $1,306,730. We note that this revenue increase is slightly lower than the revenue increase recommended by RUCO in its Exceptions to the ROO.

Rate Design

Wastewater Division

Currently, Rio Rico's wastewater customers incur a customer charge based on meter size

($7.00 for 5/8 inch meter) and a monthly sewer usage charge of $19.00. Residential customers do not incur a commodity charge based on usage, however, general services customers (multi-tenant and commercial) incur a commodity charge of $2.62 per 1,000 gallons. In this case, to simplify billing, Staff has proposed, and the Company has agreed, to combine the customer charge and the monthly usage charge into a single monthly charge. Staff also proposed to eliminate the commodity charge, except for general services customers with usage greater than 7,000 gallons per month.

Because its proposed revenue increase for the wastewater division is so great, Rio Rico proposed a three year phase-in of the wastewater rates provided its recommended revenue requirement is approved. Kozoman Rej (A-3) at 34. The Company proposes that rates increase 40 percent in year one, and a 40 percent increase in year two which will result in a total increase over present rates of 96 percent. In the third year, the Company proposes the rates will increase to the levels it ultimately proposes.

We concur with the proposed basic rate design for the wastewater division. However, based on our findings herein, the Company-proposed rates yield excess revenue. Furthermore, although our approved revenue increase for the wastewater division is less than that proposed by the Company, it is still a substantial increase. A phase-in of rate increases is necessary and reasonable to ameliorate rate shock to customers. Consequently, we authorize a three year step increase, consistent with the concept proposed by the Company to phase in the significant increase for wastewater customers. The current charges, combining the customer charge and sewer usage charge, and the approved rates, based on the revenue requirement approved here, are as follows:

Customer Classification and Meter Size	Present Rates	Step One	Step Two	Step Three
Monthly minimum charges:				
5/8 x ¾ inch	$26.00	$38.86	$51.92	$56.36
¾ inch	29.50	44.35	59.20	64.27
1 inch	36.50	54.82	73.14	79.40
1 ½ inch	54.00	81.00	108.00	117.24
2 inch	75.00	112.40	149.80	162.62

3 inch	131.00	195.98	260.96	283.30
4 inch	194.00	290.40	386.80	419.91
6 inch	369.00	552.02	735.04	797.96
8 inch	579.00	886.19	1,153.38	1,252.11
10 inch	824.00	1,232.71	1,641.42	1,781.93
12 inch	1,524.00	2,280.00	3,035.90	3,295.77
General Services Only Commodity rates (per 1,000 gallons) Applied to usage greater than 7,000 gallons for Commercial and multi-tenant only, All Sizes	2.62*	3.94**	5.26**	5.71**

* Applied to usage greater than 7,250 gallons for commercial and multi-tenant only

** Applied to usage greater than 7,000 gallons for commercial and multi-tenant only

The Company's proposed service line installation charges and service charges as reflected in its testimony are reasonable and should be adopted.

In the first year, the typical residential 5/8 inch meter monthly bill for wastewater will increase $12.86, or 40 percent, from $26.00 to $38.86. In the second year, the typical residential bill will increase another $12.86, or 33.1 percent over Year One, from $38.86 to $51.92. In the third year, the typical residential bill will increase $4.44, or 8.6 percent over Year Two, from $51.92 to $56.36.

This Order eliminates the commodity charge except for general services customers with usage greater than 7,000 gallons a month. Thus, all customers in a class are charged the same amount for wastewater service regardless of how much that customer taxes the system. However, for Rio Rico's water rates, we adopt a tiered rate design that requires customers who use more water to pay more. We find that this encourages water conservation. Some municipal wastewater systems bill their customers based on the amount of water they use. To determine if tiered wastewater rates based on water consumption would be an appropriate rate design, we will require Rio Rico to include a proposal in its next rate case filing that will present information on: 1) whether wastewater rates based on water consumption encourage water conservation; 2) whether higher bills for those who use

the system more is a fairer way to collect revenue; and 3) what tiered wastewater rates based on water consumption would look like compared to a flat rate design.

Water Division

The parties do not agree on the appropriate rate design for the water division. Rio Rico proposes a two-tier, inverted block rate design. TR at 78-79; Kozoman Rej (A-3) at 38-45. The Company's proposed commodity rate is $1.58 per 1,000 gallons for the first tier and $1.92 per 1,000 gallons for all usage in the second tier. For the 5/8 inch meter class, the break point between the tiers is 10,000 gallons. Meters larger than 5/8 inch have higher break points between tiers which increase based on meter size. Kozoman Rej (S-3) at 35-36. Currently the Company has a flat commodity rate of $1.27 per 1,000 gallons.

Rio Rico claims that its two-tier design with break-over points for each sized meter to account for different usage levels, recovers the revenue requirement proportionately for all customer classes and meter sizes. Kozoman Reb (A-2) at 62. The Company believes its design sends the appropriate price signal to all customers, especially those using more than the monthly average per class, and not just to larger users. Kozoman Reb (A-2) at 73-74, 76-77.

Rio Rico argues that the rate designs advocated by Staff and RUCO lead to disproportionate increases between customer classes. Kozoman Rej (A-3) at 38, 41; TR 112, 191-192. According to the Company, although Staff proposes a rate increase of 18.6 percent, residential customers with either 5/8 inch or ¾ inch meters experience a rate increase of only 12.4 percent (at average usage), while commercial customers experience an increase at average usage of 21 to 24 percent. Rio Rico argues such result is not conservation-oriented. It claims Staff is discounting water service and generating a subsidy by selling water below cost in the first block.

Rio Rico believes Staff is attempting to design a "lifeline" rate subsidized by larger users. TR at 200. Rio Rico argues that Staff's attempt to provide low cost water for basic needs is ill-conceived, as it asserts that a lifeline rate is intended to provide a minimum volume of water service at a reduced cost for those residential customers who find it difficult to afford because of their low income levels. As such, the Company argues, lifeline rates should only be offered to residential customers who meet eligibility requirements. According to the Company, discounted rates are

contrary to basic cost of service principles; are not commercially efficient; and the subsidy must be recovered by higher rates in other usage blocks.

The Company also argues that lifeline rates and similar types of discounts are only appropriate if the cost of water service is high relative to other, similar water utilities, or where a significant percentage of residential customers are not able to afford water service. Rio Rico asserts there is no indication such conditions are present or that Staff examined these circumstances. Finally, Rio Rico argues, lifeline rates should not be used in areas of water shortages because they may encourage greater usage contrary to conservation goals.

Rio Rico criticizes RUCO's tier design for all meter sizes with a break point of 10,000 gallons regardless of meter size. The Company claims that this design also shifts a disproportionate share of the revenue increase to larger users. For example, according to the Company, RUCO recommends an overall revenue increase of 15 percent but the increase for the 5/8 inch meter is only 10 percent compared to 29 percent for the 2 inch meter. Kozoman Reb.(A-2) at 75-77; Kozoman Rej. (A-3) at 41-45.

Staff recommends an inverted three tier rate design for residential customers on 5/8 inch and ¾ inch meters and a two tier rate design for all other customers. For the 5/8 inch and ¾ inch meter customers, Staff proposes a commodity rate of $1.07 per 1,000 gallons for the first 4,000 gallons, $1.61 per 1,000 gallons for usage between 4,001 and 20,000 gallons and $1.93 per 1,000 gallons for usage above 20,000 gallons. Staff states that because there was no cost of service study performed in this case, in designing its recommended rates, it attempted to maintain the same minimum and commodity revenue ratios as in the current rates structure. (S-8) Staff argues that its design is conservation oriented because the second tier for the residential 5/8 inch and ¾ inch meters is greater than the uniform commodity rate that would be required to recover the revenue requirement. Staff also asserts that customers will have an economic incentive to conserve water because the price of "discretionary" water (i.e. above the first 4,000 gallons) increases.

RUCO proposes a two tier inverted rate design, with a break point at 10,000 gallons for all meter sizes. Moore Sur. (R-2) at RLM-17. RUCO does not support graduated break-over points based on meter size. Moore Sur. (R-2) at 10. RUCO is concerned that under the Company's rate

design a customer with a 5/8 inch meter pays a higher commodity rate for each gallon over 10,000 gallons than a customer with a 1 inch meter. RUCO believes that regardless of meter size, the 11,000th gallon is still a precious commodity and the disparity in price is not justified by a cost of service study.

In response to Staff and RUCO concerns, Rio Rico proposed an alternative three tier commodity rate for all 5/8 inch meter customer and a two-tier rate for all other meter sizes. Kozoman Rej (A-3) at 36. The break points for the 5/8 inch meter is at 4,000 gallons, with the second tier between 4,001 and 10,000 gallons and the third tier for usage greater than 10,000 gallons. The first tier break increases for other meter sizes as the meter size increases (6,000 gallons for the ¾ inch meter, 15,000 gallons for the 1 inch meter, 20,000 gallons for the 1 ½ inch meter, etc.). The commodity rate for the first tier is $1.44 per 1,000 gallons for the 5/8 inch meter and $1.74 for the first tier for all other meter sizes. The second tier rate for larger meters is $2.00 per 1,000 gallons.

Resolution

We find that the Company's proposed 3 tier rate design (three tiers for the 5/8 inch meters and two tiers for all other meter sizes) best addresses the goals of cost-based rates that encourage conservation while providing that all meter classes bear an equitable proportion of the revenue increase. Without additional information, we are reluctant to adopt Staff's proposed first tier rate for residential 5/8 inch meters, which is lower than the current commodity cost and appears to have the result of shifting a greater proportion of the rate increase to the larger meter sizes. Further, Staff's break-over point between the second and third tiers of 20,000 gallons is too high to send the appropriate conservation price signal to heavy residential users. RUCO's design also does not create an equitable sharing of the rate increase.

Consequently, based on the revenue requirement approved herein, we approve the following rates for the water division:

	Present Rates	Approved Rates
MONTHLY USAGE CHARGE:		
5/8" x ¾" Meter	$5.00	$6.45

¾" Meter	7.50	9.65		
1" Meter	13.30	17.10		
1 ½" Meter	27.00	34.70		
2" Meter	42.00	54.00		
3" Meter	82.00	105.40		
4" Meter	135.00	173.50		
6" Meter	250.00	321.25		
8" Meter	400.00	514.00		
10" Meter	580.00	745.30		
12" Meter	1,085.00	1,395.00		
Fire lines up to 8 inches	5.00	6.48		
Fire lines 10 inches	5.80	7.45		
Fire lines 12 inches	10.85	14.00		

Commodity Charges:

		1st Tier	2nd Tier	3rd Tier
Excess of minimum – per 1,000	$1.27	$1.44	$1.70	$1.90
Upper limit gallons per tier				
5/8" x ¾" Meter		4,000	10,000	Infinite
¾" Meter			6,000	Infinite
1" Meter			15,000	Infinite
1 ½" Meter			20,000	Infinite
2" Meter			57,000	Infinite
3" Meter			57,000	Infinite
4" Meter			57,000	Infinite
6" Meter			125,000	Infinite
8" Meter			125,000	Infinite
10" Meter			125,000	Infinite
12" Meter			125,000	Infinite

SERVICE LINE AND METER INSTALLATION CHARGES:
Refundable per A.C.C. R14-

		Service Line	Meter	Total
5/8" x ¾" Meter	$485.00	$370.00	$130.00	$500.00
¾" Meter	525.00	370.00	205.00	575.00
1" Meter	590.00	420.00	240.00	660.00
1 ½" Meter	730.00	450.00	450.00	900.00
2" Meter	1,080.00	580.00	1,640.00	2,220.00
3" Meter	1,460.00	765.00	2,195.00	2,960.00
4" Meter	2,350.00	1,120.00	3,145.00	4,250.00
6" Meter	4,450.00	1,630.00	6,120.00	7,750.00
8" Meter	6,950.00	At Cost	At Cost	At Cost
10" Meter	At Cost	At Cost	At Cost	At Cost
12" Meter	At Cost	At Cost	At Cost	At Cost

SERVICE CHARGE:

Establishment	$15.00	$15.00
Establishment (After Hours)	25.00	25.00
Reconnection (Delinquent)	15.00	15.00
Reconnection (Del) – After Hours	25.00	25.00
Meter Test (If Correct)	15.00	15.00
Deposit	*	*
Deposit Interest	**	**
Reestablishment (Within 12 Months)	***	***
NSF Check	15.00	15.00
Meter Reread (If Correct)		
Late Payment Penalty		

* Per Commission rule A.A.C. R-14-2-403(B).
** Per Commission rule A.A.C. R-14-2-403(B).
*** Months off system times the monthly minimum per Commission rule A.A.C. R14-2-403(D).

The rates approved herein will increase the average 5/8 inch residential bill by $4.67, or 26.5 percent, from $17.61 to $22.28.

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. Rio Rico provides utility service to 4,200 water and 1,500 wastewater customers in the community of Rio Rico in Santa Cruz County, Arizona.

2. On June 25, 2003, Rio Rico filed an application with the Commission to raise the rates for both water and wastewater service.

3. On July 25, 2003, Staff notified the Company that its application was not sufficient under A.A.C. R14-2-103.

4. On August 4, 2003, Rio Rico provided additional information in response to Staff's list of deficiencies.

5. On September 11, 2003, Staff notified that its application was sufficient, and classified the Company as a Class B utility.

6. On September 26, 2003, the Commission granted RUCO's request to intervene.

7. By Procedural Order dated September 18, 2003, the matter was set for hearing and governing procedures set. Pursuant to the September 18, 2003 Procedural Order, Staff and RUCO filed direct testimony and schedules on March 11, 2004; the Company filed Rebuttal testimony on April 15, 2004; Staff and RUCO filed Surrebuttal testimony on May 6, 2004; and the Company filed Rejoinder testimony on May 27, 2004. The hearing convened as scheduled in Tucson, Arizona on June 3, 2004.

8. Rio Rico mailed notice of the hearing as required by the September 18, 2003 Procedural Order, to its customers on October 10, and October 28, 2003.

9. On September 21, 2004, the Commission held a public comment meeting in the Rio Rico service territory.

10. Ron Kozoman, CPA and consultant, testified on behalf of the Company. Messers. Rodney Moore and William Rigsby testified on behalf of RUCO. Messers Dennis Rogers, Joel Reiker and Lyndon Hammond provided testimony on behalf of Staff.

11. The Commission approved Rio Rico's current rates and charges in Decision No. 59547 (March 13, 1996).

12. Based on adjusted test year data, as determined herein, in the test year ended December 31, 2002, the Company's water division had Total Revenue of $1,084,065, and adjusted Operating Income of $31,354, for a 1.27 percent rate of return on an adjusted FVRB of $2,462,446.

13. Based on adjusted test year data, as determined herein, in its wastewater division, the Company experienced Total Test Year Revenues of $606,152, resulting in an adjusted operating loss of $105,248.

14. Rio Rico requested a revenue increase of $362,223, or 33.4 percent over Test Year water revenues. The Company's proposed rates would result in Operating Income for the water service of $246,395, for a 10 percent rate of return on FVRB.

15. Rio Rico requested an $869,199 increase, or 143.38 percent, over Test Year wastewater revenues. Rio Rico's request would yield Operating Income of $413,668, for a 10 percent rate of return on an adjusted wastewater FVRB of $4,136,931.

16. Rio Rico's pro forma adjustments, as reflected in its rejoinder testimony, and as

discussed herein, to include $595,657 of post test year water utility plant and $293,417 of post test year wastewater utility plant are reasonable.

17. The Company has waived reconstruction cost new less depreciation (RCND") rate base. Thus, its FVRB is the same as its OCRB. For the water division, the Company has a FVRB of $2,462,446. In the wastewater division, the Company has a FVRB of $4,136,931.

18. Rio Rico has a capital structure composed of 100 percent equity.

19. A fair and reasonable rate of return on water division FVRB is 8.7 percent.

20. The authorized revenue increase for the water division is $308,081, a 28.4 percent increase over test year revenues.

21. The rate design adopted herein for the water division will equitably apportion the rate increase among meter sizes and will promote conservation by sending the appropriate price signals to consumers.

22. As discussed herein, in order to implement fair and reasonable rates, the equities in this case warrant a graduated increase in the authorized rate of return on the wastewater division FVRB.

23. In the first year, we approve a revenue level of $905,727, an increase of $299,575, or 49.2 percent for the wastewater division, which should yield Operating Income of $80,816, and a 1.95 percent rate of return on FVRB. In the second year, we authorize Operating Revenue of $1,205,302, an increase of $299,575, or 33 percent over Year One, which will produce Operating Income of $266,880, a 6.45 percent rate of return on FVRB. In the third year, the rates we would otherwise approve herein would lead to a revenue requirement of $1,355,089, an increase of $149,787, or 12.4 percent over the second year revenues, which will yield Operating Income of $359,912, and an 8.7 percent rate of return on FVRB. However, to further offset the impact of increased rates on its customers, Rio Rico has agreed to a reduction in the revenue increase that would otherwise result from our order such that the total increase we approve herein is $700,103, or 115.41 percent higher than test year revenues when the rates are in place in the third year for a total revenue requirement of $1,306,730. We note that this revenue increase is slightly lower than the revenue increase recommended by RUCO in its Exceptions to the ROO.

24. The Arizona Department of Environmental Quality ("ADEQ") reports that Rio Rico's water and wastewater systems are in total compliance with its rules and regulations. ADEQ determined that the drinking water system is currently delivering water that meets state and federal drinking water quality standards required by the Arizona Administrative Code, Title 18, Chapter 4.

25. Rio Rico is located within the Santa Cruz Active Management Area and is in compliance with the Department of Water Resources reporting and conservation requirements.

26. Rio Rico has no outstanding Commission compliance issues.

27. The U. S. Environmental Protection agency ("EPA") reduced the arsenic maximum contaminant level ("MCL") in drinking water from 50 micrograms per liter (µg/l) to 10 µg/l. The date for compliance with the new MCL is January 23, 2006. An analysis of Rio Rico's arsenic levels indicates levels between 3 and 5 µg/l at each well. Based on this data, the Company is in compliance with the new MCL.

28. A curtailment tariff is an effective tool to allow a water company to manage its resources during periods of shortages due to pump breakdowns, droughts, or other unforeseeable events. Rio Rico does not have a curtailment tariff. Staff believes the current application provides an opportune time for Rio Rico to prepare and submit such tariff. Staff recommends that Rio Rico file a curtailment tariff within 45 days after the effective date of this Decision. The tariff should be submitted to the Director of the Utilities Division for his review and certification and should conform to the sample tariff found on the Commission's web site or available from Staff.

CONCLUSIONS OF LAW

1. Rio Rico is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-250 and 40-251.

2. The Commission has jurisdiction over Rio Rico and of the subject matter of the applications.

3. Notice of the application was given in accordance with the law.

4. The rates and charges approved herein are reasonable and should be approved.

5. Staff's recommendation set forth in Findings of Fact No. 28 is reasonable and should

be adopted.

ORDER

IT IS THEREFORE ORDERED that Rio Rico Utilities Inc. shall file with the Commission on or before September 30, 2004, revised schedules of rates and charges consistent with the rates approved herein.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after October 1, 2004.

IT IS FURTHER ORDERED that Rio Rico shall include a proposal in its next rate case filing that will present information on: 1) whether wastewater rates based on water consumption encourage water conservation; 2) whether higher bills for those who use the system more is a fairer way to collect revenue; and 3) what tiered wastewater rates based on water consumption would look like compared to a flat rate design.

IT IS FURTHER ORDERED that Rio Rico Utilities Inc. shall notify its customers of the revised schedules of rates and charges authorized herein by means of an insert in its next regularly scheduled billing, in a form approved by Staff.

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IT IS FURTHER ORDERED that Rio Rico Utilities Inc. shall file a curtailment tariff within 45 days after the effective date of this Decision. The tariff should be submitted to the Director of the Utilities Division for his review and certification and should conform to the sample tariff found on the Commission's web site or available from Staff.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN | COMMISSIONER | COMMISSIONER

COMMISSIONER | COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 5th day of October, 2004.

BRIAN C. McNEIL
EXECUTIVE SECRETARY

DISSENT

DISSENT

JR:

SERVICE LIST FOR: RIO RICO UTILITIES , INC.

DOCKET NO.: WS-02676A-03-0434

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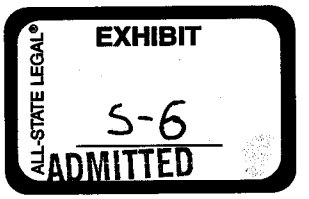

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-04204A-08-0571

(PUBLIC)

DIRECT

TESTIMONY

OF

RITA R. BEALE

ON BEHALF OF THE STAFF OF THE

ARIZONA CORPORATION COMMISSION

JUNE 08, 2009

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EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NO. G-04204A-08-0571

In April and May 2009, I conducted a prudency review of the gas procurement operations of UNS Gas, Inc. My testimony focused on the period from January 2006 to June 2008, with nine findings and also ten recommendations for the Commissioners to consider. I reviewed the decision to terminate the BP Energy Services contract, the commodity and pipeline charges of the PGA Bank Balances, individual transactions, future pipeline planning, purchasing strategies and policies, and observed first-hand the Day Ahead gas purchasing, nominating and scheduling processes. My recommendations are:

(1) UNS Gas should conduct a thorough analysis of excess interstate pipeline capacity that could be currently optimized through Asset Management Arrangements (AMA).

(2) If excess pipeline capacity is available, UNS Gas should have Tucson Electric Power ("TEP"), seek potential counterparties on UNS Gas' behalf, at least annually, to optimize all of its excess capacity on both Transwestern and the El Paso Pipeline, although not at the expense of incurring a net increase in El Paso charges and penalties.

(3) UNS Gas should be required to supplement the information filed monthly to the Commission to tie out and support all entries of the Purchased Gas Adjustor Bank Balance, and specifically to include the *UNS Gas Core Market/ System Supply Imbalance Report* which finalizes tie-out of the commodity balances by pipeline.

(4) To ensure accuracy of the PGA filings, personnel from the Energy Settlements & Billing Department should receive additional training in the operating practices and terminology used by TEP Wholesale Department for gas procurement.

(5) The *UNS Gas Inc. Price Stabilization Policy* should be changed to require consideration of purchases during the three excluded months of August, September and October. Automatically excluding these months created missed opportunities to buy lower-priced gas during 2006, 2007 and 2008.

(6) To increase its hedge documentation, UNS Gas should create a record indicating the months that management decides to deviate from a ratable purchasing pattern,[1] even if it as simple as using a checklist denoting 'management decided not to hedge'.

(7) The *UNS Gas Inc. Price Stabilization Policy* should also be amended for any changes to gas purchasing strategy effective September 2008, when TEP took over gas procurement.

(8) The *UNS Gas Inc. Price Stabilization Policy* must be updated at least annually to reflect current practices and procedures.

(9) All parties involved with gas procurement should acknowledge the *UNS Gas Inc. Price Stabilization Policy* by signing annually, including Gas Scheduling, Transportation Contracts, Risk Management, and Risk Control; not just the traders.

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[1] The *UNS Gas Inc. Price Stabilization Policy* essentially sets a non-discretionary portion of forecasted gas load (minimum 45 percent) to be hedged with fixed price instruments at ratable quantities of 1/27th over 27 different months leading up to the physical flow month, excluding August, September and October.

(10) A single person should be assigned as the 'policy owner' of the *UNS Gas Inc. Price Stabilization Policy* to ensure, on an annual basis, that the policy is accurate before it is approved by the Corporate Risk Management Committee.

INTRODUCTION

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

A. My name is Rita Regina Beale. I am a consultant employed with Energy Ventures Analysis, Inc. ("EVA"). My business address is 1901 N. Moore Street, Suite 1200, Arlington, Virginia 22209-1706.

Q. Please summarize your educational background and professional experience.

A. I am a graduate of Rider University and the Colorado School of Mines with a Bachelor of Science in Geology and Master of Science in Mineral Economics, from these respective institutions. I have about 22 years of varied energy commodity experience in oil, gas and electricity, with about eight years as an energy commodity analyst on Wall Street, mostly at Lehman Brothers and Goldman Sachs. I also spent about four years as a Senior Manager with Arthur Andersen in financial and commodity risk consulting. And I have been Vice President at two deregulated power companies, responsible for wholesale power supply and trading at Idaho Energy LP and First Choice Power LP in Texas. Currently I am a Principal with EVA.

Q. What are your duties and responsibilities at EVA?

A. I serve as a consultant and analyst at EVA. EVA is nationally known for its work in the energy and emission fields and engages in a variety of consulting projects for the private and public sector. I have worked on behalf of the Staff of the Arizona Corporation Commission in two prior rate cases, Dockets G-01551A-07-0504 and E-01933A-07-0402. In the energy area, much of our work is related to analysis of the electric power industry, fuel markets, and the transportation thereof. EVA's clients include fuel producers, electric and gas utilities, industrial energy consumers, transporters, and private investors in energy industries. Exhibit RB-1 presents my resume at the end of this testimony.

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

A. I am appearing on behalf of the Staff of the Arizona Corporation Commission-Utilities Division ("ACC") to address the prudency and reasonableness of the gas procurement practices of UNS Gas, Inc. ("UNS Gas") from January 2006 to June 2008. Also my testimony discusses operational and role changes for UNS Gas since September 2008.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your testimony is organized.

A. My gas procurement testimony is organized into seven sections. Section one discusses the reasons for the termination of BP Energy Services as UNS Gas' full requirements supplier and the transition to taking gas procurement in-house to Tucson Electric Power ("TEP") Wholesale Department.[2] Section two discusses planning for future UNS Gas pipeline capacity. Section three presents my audit of the Purchased Gas Adjustor Bank. In section four, I comment on UNS Gas purchasing strategies. Section five examines UNS Gas policies and procedures. The final two sections discuss an on-site visit to observe daily purchasing, nominating and scheduling and an audit of selected transactions. Exhibits RB-2 through RB-7 support my findings and recommendations.

Q. Please summarize your additional findings.

A. My findings are:

(1) No formal cost/benefit study was conducted by UNS Gas when deciding to discontinue the relationship with BP Energy Services as its full requirements supplier and to instead bring gas supply, nomination and scheduling operations into TEP Wholesale Department, as of September 2008. While some types of

[2] TEP and UniSource Energy Services are both subsidiaries of the publically traded entity, UniSource Energy Corporation, based in Tucson, Arizona. Under UniSource Energy Services, UNS Gas is the regulated gas utility that serves Arizona ratepayers with gas commodity and operates the physical system.

costs will increase during the short run, for instance associated TEP personnel costs, it was a rational decision and other important types of benefits are being realized by ratepayers that should continue long term.

(2) An audit of the PGA Bank Balance was conducted specifically for commodity and pipeline charges and credits. It reconciled the underlying charges and credits to within $9,834 of the filed PGA amount, compared to total charges of $240,522,666 for January 2006 to June 2008. Categories examined include (a) fixed price hedge transactions, (b) First of Month Index purchases, (c) Day Ahead purchases, (d) pipeline transportation charges, and (e) pipeline commodity balances that are carried forward, along with other items.

(3) Three primary strategies were used to purchase gas and found to generally balance price stability and supply reliability. However, one component of the fixed price hedge strategy is ineffective and should be revised per my recommendations.

(4) While company policies and procedures are generally reasonable, the UNS Gas Stabilization Policy 2009 is out of date, and no longer reflects all current procedures and practices.

(5) Purchase prices of natural gas commodity appeared reasonable relative to industry data, and the amount of pipeline capacity appeared prudent during the study period.

(6) A review of the analysis of normal peak day load and design day load requirements against pipeline capacity through 2011 found that current pipeline capacity contracts are likely to be sufficient for several additional years, possibly through 2013, although there is a lot of uncertainty about load growth given the recession and potential federal carbon legislation.

(7) Pipeline penalties and other charges, which are in addition to the typical demand and usage charges, were reasonable.

(8) An on-site visit to TEP Wholesale Department was made on April 14, 2009, to witness and analyze Day Ahead gas purchasing, nominating and scheduling processes. Purchases and practices were found to be reasonable, including bidder award.

(9) Six transactions were audited and found to be compliant with company policies and procedures.

Q. Please summarize your recommendations for the Commission to consider.

A. I have ten recommendations, in order of discussion within my testimony:

(1) UNS Gas should conduct a thorough analysis of excess interstate pipeline capacity that could be optimized through Asset Management Arrangements ("AMA").

(2) If excess pipeline capacity is available, UNS Gas should have TEP seek potential counterparties on UNS Gas' behalf, at least annually, to optimize all of its excess capacity on both Transwestern and also on El Paso Pipeline, although not at the expense of incurring a net increase in El Paso charges and penalties.

(3) UNS Gas should be required to supplement the information filed monthly to the Commission to tie out and support all entries of the Purchased Gas Adjustor Bank Balance, and to specifically include the UNSG Core Market/ System Supply Imbalance Report which finalizes tie-out of the commodity balances by pipeline.

(4) To ensure accuracy of the PGA filings, personnel from the Energy Settlements & Billing Department should receive additional training in the operating practices and terminology of TEP Wholesale Department for gas procurement.

(5) The UNS Gas Inc. Price Stabilization Policy should be changed to require consideration of purchases during the three excluded months of August, September and October. Automatically excluding these months created missed opportunities to buy lower-priced gas during 2006, 2007 and 2008.

(6) To increase its hedge documentation, UNS Gas should create a record indicating the months that management decides to deviate from a ratable purchasing pattern,[3] even if it as simple as using a checklist denoting 'management decided not to hedge'.

(7) The UNS Gas Inc. Price Stabilization Policy should also be amended for any strategy changes effective September 2008, when TEP took over gas procurement.

(8) The UNS Gas Inc. Price Stabilization Policy must be updated at least annually to reflect current practices and procedures before being approved by the Corporate Risk Management Committee.

(9) All parties involved with gas procurement should acknowledge the UNS Gas Inc. Price Stabilization Policy by signing annually, including Gas Scheduling, Transportation Contracts, Risk Management, and Risk Control, and not just the traders.

(10) A single person should be assigned as the 'policy owner' of the UNS Gas Inc. Price Stabilization Policy to ensure, on an annual basis, that the policy is accurate before it is approved by the Corporate Risk Management Committee.

GAS PROCUREMENT CHANGES FROM BP TO TEP WHOLESALE

Q. What was the relationship with BP Energy Services during the audit period?

A. BP Energy Services provided UNS Gas with natural gas supply at full requirements, and in return UNS Gas provided BP Energy with rights to optimize UNS Gas' interstate pipeline capacity. Any upside value was split equally by UNS Gas ratepayers and BP. The full requirements service allowed UNS Gas to take more gas (swing up), or send back excess gas (swing down), on a daily basis as load requirements dictated. Such swing

[3] The *UNS Gas Inc. Price Stabilization Policy* essentially sets a non-discretionary portion of forecasted gas load (minimum 45 percent) to be hedged with fixed price instruments at ratable quantities of 1/27th over 27 different months leading up to the physical flow month, excluding August, September and October.

transactions occurred at [redacted]. The agreement required UNS Gas to provide a daily forecast of its load to BP Energy.

Q. When did the relationship between the two parties change?

A. Contractually, gas procurement services ended with BP Energy Services on August 31, 2008 and began in TEP Wholesale Department starting September 1, 2008. As a result, BP's role changed to become one of a number of suppliers canvassed by UNS Gas to purchase gas.

Q. Why did the transition occur?

A. In 2006, El Paso Pipeline dramatically changed its rates and tariff structure, to require several types of no-notice and other services, which effectively prevented shippers from swinging quantities on a daily and intraday basis, unless shippers paid for the flexibility, also referred to as "optionality". When all of the optionality is monetized by a shipper, the assets are considered fully optimized. Subscription to the new swing services was expensive, and shippers were extremely likely to be caught by other charges and penalties if they did not buy a prescribed set of no-notice services. Under the new El Paso regime, entities serving full requirements loads, like UNS Gas, also found that to minimize additional charges and penalties, they needed to retain any excess hourly capacity to be rolled forward through the day for use by their own load to credit against future hours of higher than anticipated load. In such a different environment, it became difficult for BP to provide UNS Gas with the same daily swing services at the same low price.

Q. Why is optimization so important to ratepayers?

A. If the pipeline contracts are not used to serve the ratepayers' load, they become idle assets simply incurring expenses. Optimization presents an opportunity to recover some of those expenses.

Q. What was the value of the pipeline optimization component?

A. During the study period, UNS Gas ratepayers benefited by [redacted] by their 50 percent share, although the final month of any optimization whatsoever was November 2007, and only $12,931 was paid to UNS Gas during the final twenty out of thirty months examined.

Q. What was BP Energy's final offer to retain the UNS Gas account?

A. In July 2008 and in view of the natural cessation of El Paso pipeline optimization, BP's offer was contingent on collection of a monthly scheduling and nomination service charge of [redacted].

Q. Was UNS Gas able to find a better partner?

A. Yes, for pipeline optimization. As of March 2009, the new capacity on the Transwestern Phoenix Lateral was not required to serve ratepayer load, although UNS Gas must pay pipeline demand charges to hold the capacity in reserve. Subsequently for March 2009,

this new capacity was released in an AMA to Tenaska Marketing Ventures (TMV). Ratepayers have benefitted from a better sharing arrangement of [redacted]. For March 2009, the difference between [redacted], in favor of ratepayers, *ceteris paribus*, to offset the otherwise idle pipeline capacity.

Q. Are there any other benefits that derive to UNS Gas ratepayers?

A. UNS Gas has gained the benefit of first hand price discovery by virtue of TEP's direct participation in the market, whereas formerly BP was the entity facing the market. UNS Gas also retains the choice of changing AMA partners should market conditions warrant, both of which should help lower the gas supply and transport costs over the long term. There should be increased accountability for decision-making during severe and critical pipeline operating conditions. Sharing of the cost of gas procurement operations with two UniSource entities, Tucson Electric and UNS Electric is another benefit. UNS Gas's load is winter peaking versus summer peaking for the electric companies, so they are a natural complement. Other benefits are related to credit risk management which is essential to lock-in purchases of gas in the forward markets. UNS Gas's counterparty credit risk is theoretically more diversified by using multiple gas suppliers, and UNS Gas should be able to access a greater amount of credit by using multiple suppliers.

Q. What are the O&M costs of gas procurement for UNS Gas?

A. Based on UniSource internal documentation, UNS Gas's O&M for gas procurement had average quarterly increases of 7.3 percent for the four quarters through 1Q2009, as a result of all items, including changes in gas procurement personnel. If the 1Q2009 increase over 1Q2008 is annualized, it equals $60,571.

FUTURE PIPELINE CAPACITY PLANNING

Q. Did you review UNS Gas's planning for future pipeline capacity needs, and if so, what were your findings?

A. Yes, I reviewed the interstate contract quantities against normal peak day load and design day load requirements through 2011. Given the recession and potential federal legislation regulating carbon, prior load growth estimates may be too high. I recommend that UNS Gas conduct a new analysis of excess interstate pipeline capacity that could be optimized through Asset Management Arrangements ("AMA").

Q. Were there any changes to the pipeline portfolio?

A. Yes. The most significant change resulted from the changes in the new El Paso rates and tariff on January 1, 2006. The most recent change is that UNS Gas expanded its total pipeline capacity by committing to the new Phoenix Lateral effective March 1, 2009. UNS Gas sought and was granted Commission pre-approval for acquisition and cost recovery of this new capacity in Docket G-04204A-0627, Decision No. 69333, partly to ensure diversification of gas supplies into the region and also away from the traditional monopoly held by El Paso Pipeline.

Q. For how long will the current pipeline capacity be sufficient?

A. Mr. David Hutchens, Vice President of Wholesale Energy and UNS Gas, believes the current portfolio may be sufficient through 2013. In all parts of the United States, there is great uncertainty about the amount of future load growth, given the current recession and potential federal legislation regulating carbon.

Q. Are you satisfied that all pipeline optionality is being monetized?

A. There is currently quite a bit of excess pipeline capacity, and because UNS Gas's load has declined due to recession, there may additional excess capacity that was not previously available. I recommend that after UNS Gas conducts a new analysis of excess pipeline capacity, that UNS Gas have TEP seek potential counterparties on behalf of UNS Gas, at least annually, to optimize all of the excess capacity on both Transwestern and also on El Paso Pipeline, although not at the expense of incurring a net increase in El Paso charges and penalties.

PURCHASED GAS ADJUSTOR BANK

Q. Did you review the PGA accounting?

A. Yes. I focused on validating the commodity and transportation expenses of the PGA Bank Balance Statement (primarily Exhibit A, lines 2 and 3) for the 30-month study period.

Q. What was your approach?

A. To the extent practical, I examined all available underlying transaction data from the system of record and compared it to PGA filings. Because BP was the full requirements supplier, First of Month and Day Ahead purchases are not contained in the system of record, and instead have been aggregated on internal spreadsheets. I also examined all the pipeline charges that were aggregated on internal spreadsheets.

Q. What were your findings?

A. For the 30-month study period, I reconciled the underlying charges and credits to within $9,834 of the filed PGA amount. Total costs filed to be recovered were $240,522,666, per Exhibit A, line 6.

Q. Why couldn't you reconcile to the penny?

A. The true-up process is fairly complex, and it was difficult to reconcile all of the charges without better documentation support. I strongly recommend that UNS Gas be required to tie out and supplement that information to the Commission each month with the filed PGA reports. Past testimony by Staff witness George Wennerlyn in February 9, 2007 (Docket G-04204A-06-0463, G-04204A-06-0413, G-04204A-06-0831) supported a similar finding and recommendation. I also specifically recommend that the Commission to require that the *Core Market/System Supply Imbalance Report* be added to the required documentation support for filing.

Q. What is in the *Core Market/System Supply Imbalance Report*?

A. The core market commodity imbalance is entered on Exhibit B, line 26, of the monthly filed PGA reports. This internal UNS Gas report supports it and attempts to reconcile all of the mismatches between scheduled and actual volumes and the final charges to the core ratepayers. Each month, pipeline imbalances can be cashed-out in the current month, carried forward into the next month, or resolved by additional transactions with a third party. During the study period, the core market commodity imbalance totaled a net credit of $380,045 to ratepayers, but experienced monthly swings from a credit of $694,132 to a debit of $805,657. To ensure these swings are not imprudent, their genesis and resolution need to be tracked easily.

Q. Do you have any other recommendations to share on the PGA?

A. Yes. Since January 2009, the Energy Settlements & Billing Department took internal responsibility to prepare the PGA reports, with final oversight responsibility designated to a single person in TEP. To ensure accuracy of the PGA filings, I recommend that personnel from the Energy Settlements & Billing Department receive additional training in the operating practices and terminology of gas procurement in TEP Wholesale.

Q. What led you to this conclusion?

A. I received errant data in response to formal data request RB 4.1, compiled by Energy Settlements & Billing Department. I believe the errors were not intentional, but due to a lack of understanding about some of the details of wholesale gas procurement, as the Analyst had not been working with the data for very long. There are number of complex processes that require considerable experience to be completely familiar with terminology unique to gas procurement.

GAS PURCHASING STRATEGIES

Q. What were the UNS Gas purchasing strategies?

A. UNS Gas used three primary strategies to purchase gas: fixed price hedges, First of the Month Index and Day Ahead Index, supplemented by two lesser strategies: Intraday purchases and the carry forward of pipeline imbalances. Exhibit RB-2 shows the monthly percentage of the volume of gas purchased by each primary strategy. By dollar value during the study period, $113,948,609 of gas was purchased with fixed price hedges, $32,289,078 of gas was purchased at First of the Month Index, and $66,781,956 of gas

was purchased at Day Ahead Index. These values are before adjustments due to core market commodity imbalance, T-1[4] imbalances, NSP[5] margins, and financial hedges.

Exhibit RB-2

Primary Purchasing Strategies for Scheduled Delivery Volumes

	Hedge Quantity	FOM Quantity	Daily Quantity	Delivered Core Purchases
Jan-06	65%	17%	18%	100%
Feb-06	55%	34%	11%	100%
Mar-06	42%	12%	46%	100%
Apr-06	58%	14%	28%	100%
May-06	68%	22%	9%	100%
Jun-06	47%	24%	29%	100%
Jul-06	49%	29%	22%	100%
Aug-06	46%	29%	25%	100%
Sep-06	42%	21%	37%	100%
Oct-06	38%	9%	53%	100%
Nov-06	50%	26%	24%	100%
Dec-06	47%	17%	37%	100%
Jan-07	47%	9%	44%	100%
Feb-07	47%	18%	35%	100%
Mar-07	55%	13%	31%	100%
Apr-07	57%	7%	36%	100%
May-07	66%	8%	26%	100%
Jun-07	62%	22%	16%	100%
Jul-07	50%	28%	22%	100%
Aug-07	49%	27%	24%	100%
Sep-07	59%	24%	17%	100%
Oct-07	50%	11%	38%	100%
Nov-07	66%	27%	8%	100%
Dec-07	51%	14%	34%	100%
Jan-08	56%	6%	38%	100%
Feb-08	50%	12%	38%	100%
Mar-08	57%	9%	34%	100%
Apr-08	55%	12%	33%	100%
May-08	45%	15%	40%	100%
Jun-08	42%	24%	35%	100%

[4] "T-1" refers to the Pricing Plan T-1, Transportation of Customer-Secured Natural Gas, such that a customer procures its own gas to the UNS Gas city gate and UNS transports the gas thereafter to the customer's downstream facility.

[5] "NSP" is Pricing Plan NSP-1, the Negotiated Sales Program, such that a customer has negotiated with UNS Gas for the delivery of natural gas commodity.

Q. Can you describe the fixed price strategy?

A. It is documented in the *UNS Gas Inc. Price Stabilization Policy.* For fixed price purchases, UNS Gas is required to lock the price of gas to reach a minimum of 45 percent of the forecasted load by two months prior to physical flow. There is no discrimination between physical and financial instruments, although UNS Gas has traditionally chosen to execute primarily physical instruments. The policy recommends that the 45 percent be spread out over three years in about 27 separate monthly transactions to accomplish effective dollar cost averaging. Also, purchases are required to be excluded during the three months of August, September and October due to potentially high hurricane activity.

Q. Do you think the fixed price strategy is prudent?

A. Generally, I think it is reasonable. My primary criticism is that I believe the concept of automatically eliminating August through October from the purchase schedule is inherently flawed, since those months can give rise to both lower and higher prices.

Q. Please provide some illustrations of this phenomenon for the excluded months?

A. During the past three years of 2006, 2007 and 2008, the excluded months were not necessarily high priced periods, relative to the other nine months of the year. Settlement of the NYMEX Henry Hub futures contract, which is a core component in setting the fixed price at San Juan for any transaction, reached some of its lowest values of the year during the excluded months. Exhibits RB-3 and RB-4 provide examples during the lifetime of two NYMEX Henry Hub futures contracts, the December 2007 and December 2009 contracts, respectively. Simple observation of the graphs indicates that the excluded periods were often lower than the other nine months of the year in 2006, 2007 and 2008.

Exhibit RB-3

History of December 2007 NYMEX Henry Hub Futures Contract

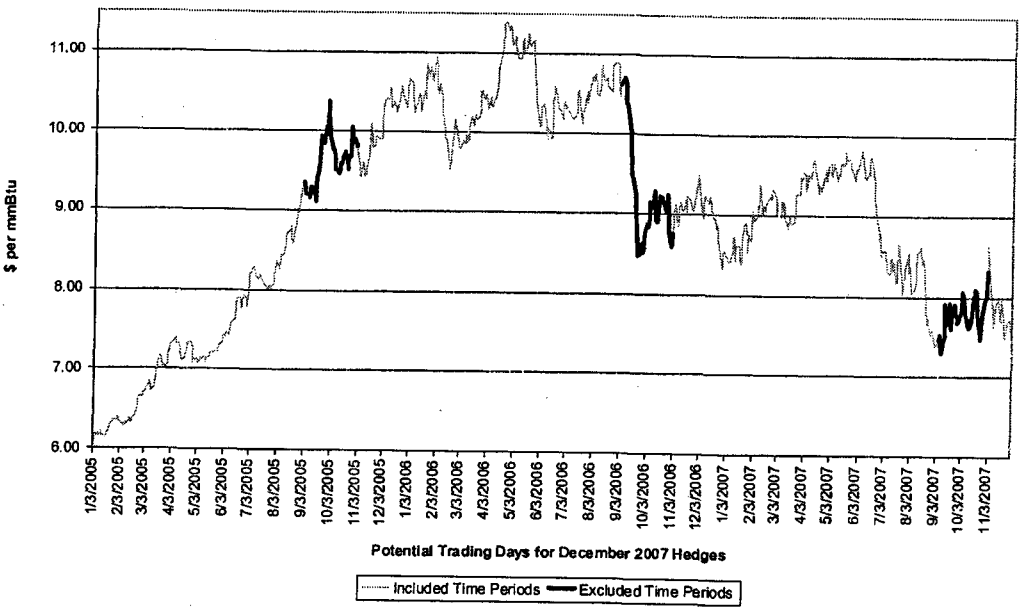
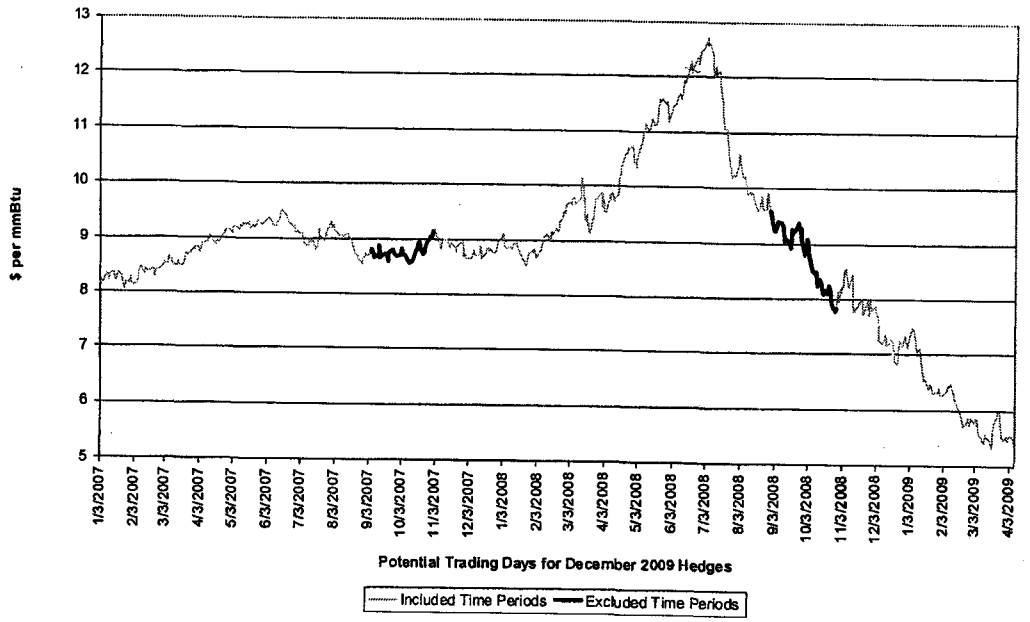


Exhibit RB-4

History of December 2009 NYMEX Henry Hub Futures Contract



Q. What else makes you think the strategy is flawed?

A. The United States is currently in a period of generally weak gas prices, so it would be prudent to take advantage of this weakness through fixed price hedges. As a point of reference, the *Inside FERC* First of Month Index for May 2009 gas delivered to El Paso San Juan settled at only $2.50 mmBtu. In my opinion, there is more risk that gas prices will rise after 2009 than decline, so automatically eliminating purchases during August 2009, September 2009 and October 2009 may not be prudent. There could be good buying opportunities for the 36-month strip, which is the focus of UNS Gas' hedging program.

Q. What are the dynamics that might keep prices low during 2009?

A. There is a strong likelihood that U.S. working gas storage will reach full capacity ahead of the traditional November 1st date, which would tend to strand excess gas on the pipeline system keeping prices in a weakened state. Storage is expected to reach full capacity early this year because on average U.S. natural gas production is still rising versus 2008, but U.S. consumption has not yet bottomed versus 2008.

Q. Do you recommend that the *UNS Gas Inc. Price Stabilization Policy* be amended, and if so, how?

A. Yes, I recommend that the policy be changed to require consideration of purchases during the three excluded months, since automatically excluding them created missed opportunities to purchase lower priced gas in 2006, 2007 and 2008. Also, I recommend that the policy be amended for any strategy changes effective September 2008, when TEP took over gas procurement.

Q. Should the policy be changed every year?

A. Not necessarily, although it is Best Practice for a management team to examine the performance of its hedging policy after-the-fact to determine where the policy succeeded and where it failed. The *UNS Gas Inc. Price Stabilization Policy* has had virtually no changes during the past four versions that I reviewed. In the last UNS Gas rate case, Docket No. G-04204A-06-0463, staff witness Mr. Jerry Mendl warned of such a potential risk, "approval of the (2006 Gas Price Stabilization) policy would create a safe harbor that would increase the resistance of UNS Gas to change polices when conditions warranted". The requirement to exclude August, September and October may have appeared reasonable during 2005, but does not appear reasonable during 2006, 2007 and 2008.

Q. Do you recommend that any of their gas purchases be deemed not prudent for these reasons?

A. No. No one can have perfect foresight, and that is why the policy must be reviewed in hindsight to determine its effectiveness. Also, there is a learning curve associated with any new policy. UNS Gas' ability to apply its discretion and judgment during the hedging process is allowed by the policy, and it should be retained due to rapidly changing natural gas markets. This makes hedge documentation more onerous, an area where TEP performs poorly.

Q. Did UNS Gas adhere to its fixed price strategy?

A. Exhibit RB-5 shows that UNS Gas met the 45 percent target each month. It also measures the final quantities hedged against several vintages of load forecasts, which are issued annually by UniSource Financial Forecasting Department. The changes illustrate the volatility of the load forecast going back in time, because the same final hedge quantities are compared against load forecasts of prior years.

Exhibit RB-5

Percent of UNSG Load Hedged Forward				
	By Vintage of Load Forecast			
Delivery Month	2005	2006	2007	2008
Jan-06	60%	70%		
Feb-06	56%	56%		
Mar-06	53%	57%		
Apr-06	48%	48%		
May-06	53%	57%		
Jun-06	50%	53%		
Jul-06	49%	54%		
Aug-06	47%	48%		
Sep-06	48%	51%		
Oct-06	48%	45%		
Nov-06	50%	49%		
Dec-06	57%	48%		
Jan-07	51%	59%	61%	
Feb-07	48%	48%	50%	
Mar-07	49%	52%	51%	
Apr-07	53%	53%	57%	
May-07	49%	52%	56%	
Jun-07	53%	56%	67%	
Jul-07	51%	56%	54%	
Aug-07	46%	47%	48%	
Sep-07	53%	56%	60%	
Oct-07	53%	50%	52%	
Nov-07	55%	54%	50%	
Dec-07	63%	52%	55%	
Jan-08	58%	67%	70%	69%
Feb-08	57%	56%	60%	59%
Mar-08	55%	59%	57%	56%
Apr-08	46%	45%	50%	56%
May-08	43%	46%	49%	55%
Jun-08	43%	45%	55%	52%

Q. Did UNS Gas adhere to discipline of making 27 purchases for each month?

A. Exhibit RB-6 shows that the discipline of making 27 monthly purchases for each month was not perfectly executed. The low numbers in the beginning of the study period are affected by a prior policy that required a fewer number of trades, then the policy increased the recommended number of trades. The transaction data underlying Exhibit RB-6 show a lack of perfect discipline. For instance, during November 2005, hedges were not executed for months beyond March 2006. No hedges were executed during December 2005. Then

27 transactions were executed during January 2006. A fixed price hedge was last executed for the flow month of June 2008 during December 2007. There are other examples of imprecise execution of the strategy.

Exhibit RB-6

	Number of Physical & Financial Hedge Transactions
Jan-06	7
Feb-06	6
Mar-06	6
Apr-06	6
May-06	8
Jun-06	8
Jul-06	11
Aug-06	12
Sep-06	13
Oct-06	13
Nov-06	14
Dec-06	14
Jan-07	14
Feb-07	13
Mar-07	15
Apr-07	13
May-07	15
Jun-07	15
Jul-07	18
Aug-07	19
Sep-07	21
Oct-07	13
Nov-07	13
Dec-07	21
Jan-08	22
Feb-08	21
Mar-08	21
Apr-08	19
May-08	19
Jun-08	19

Q. Does this concern you?

A. No, there is increasing adherence to the concept of executing 27 transactions for each month, which is acceptable. I did not query management on the exact reasons for each of the deviations from the frequency recommended by the policy for several reasons.

Changes to company-issued annual load forecasts can cause management to change the buying pattern. Management retains a discretionary component to the purchasing strategy, which appears to be surfacing in the purchasing patterns. The deviations from an expected 27 transactions seem to also show the difficulty of hedging mechanically without judgment, when management is allowed discretion in the policy.

Q. Are the deviations documented?

A. No, and I recommend to increase its hedge documentation, UNS Gas should create a record indicating the months that management decides to deviate from a ratable purchasing pattern, even if it as simple as using a checklist denoting 'management decided not to hedge'. My general experience has been that parties often have reluctance to record the exact reasons for each deviation, lest the often complex events associated with each determination be examined in hindsight under the microscope. Of course, the hedged transactions serve as proof of management's decisions about when to execute the ratable purchase policy.

Q. What are the second and third legs of the UNS Gas purchasing strategy?

A. As verbally described by the Portfolio Manager of gas purchasing, Mr. Ray Robey, the second and third legs of the purchase strategy involved buying the remainder, not already covered by hedges, roughly split between First of Month Index and Day Ahead Index. For instance, if forward hedges covered 45 percent, about 27.5 percent would be FOM and about 27.5 percent would be Day Ahead. It should be noted that the UNS Gas strategy appears to have changed somewhat after TEP took over gas procurement, starting September 2008.

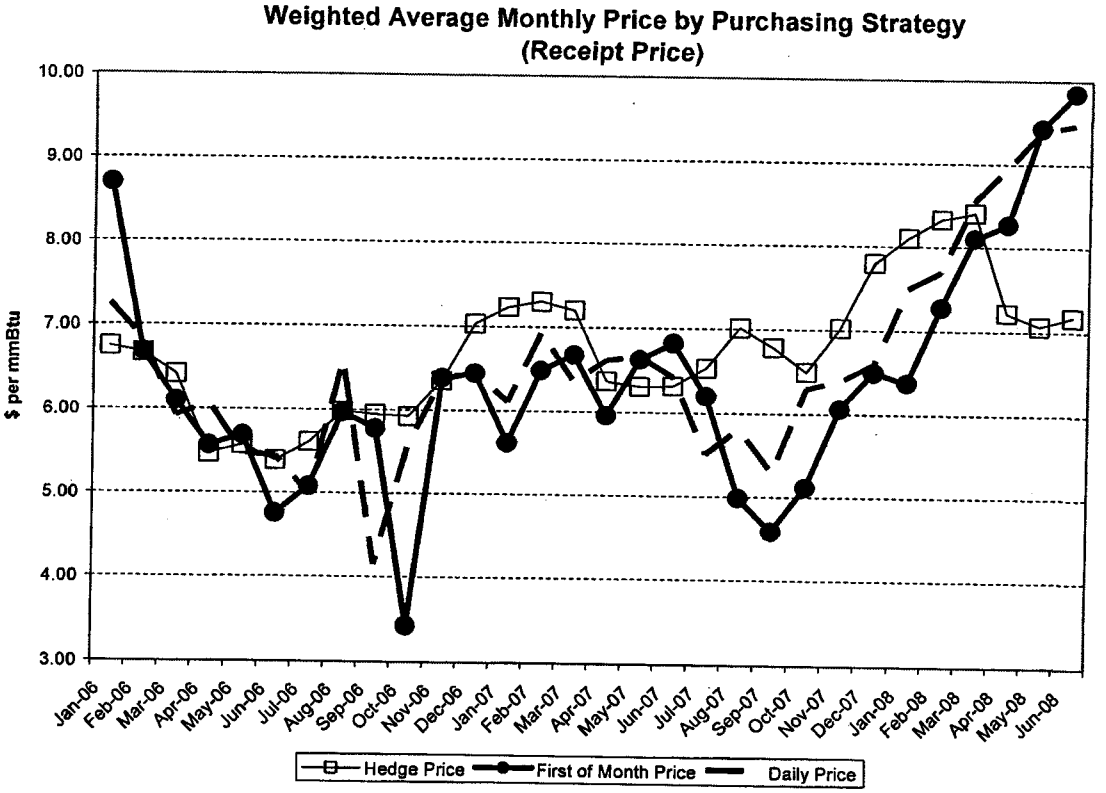
Q. Why not purchase all of the remainder in the FOM market?

A. Because weather, and therefore load, is impossible to predict with complete accuracy, it is prudent to take account of a potentially better and more real time weather forecast in the load estimate, before determining the final amount of gas to purchase.

Q. Were the resultant purchase prices reasonable?

A. Yes, all prices appear reasonable. Because UNS Gas purchased gas from BP at FOM Index and GDD Index, index prices are reasonable. These prices were checked independently for accuracy with the published indexes. Analyzing the reasonableness of the average hedge price is based on hedge strategy actually employed, as discussed earlier. Receipt prices paid by UNS Gas are shown in Exhibit RB-7 for the three primary purchasing strategies. Hedge prices are weighted by volume.

Exhibit RB-7



Q. Were the pipeline charges reasonable?

A. Yes. I reviewed all pipeline charges incurred by UNS Gas during the study period including demand, usage, and all the other types of charges including penalties. The additional pipeline charges beyond demand and usage paid to El Paso Pipeline appear reasonable, and somewhat unavoidable, given the newness and difficult to implement standards of the El Paso Pipeline tariff effective beginning January 1, 2006, and the uncontrollable weather events occurring in November 2006. The general nature of the new tariff attempts to remove all optionality from the shipper, unless the optionality is subscribed to and paid for. El Paso subsequently revised many of the difficult to implement operating requirements, that began on January 1, 2006, sometimes by order of the FERC and after complaints from the shippers. Also by order of the FERC, El Paso

refunded $219,645 of charges and penalties incurred by UNS Gas from August 2006 to September 2007.

Q. What were the amounts of pipeline charges paid by each category?

A. UNS Gas paid a gross total of $30,222,222 million, with $29,123,375 of pipeline charges flowing through to the PGA before credits and debits with NSP and T-1 customers and after El Paso refunds.[6] Gross El Paso charges included $22,009,443 in demand charges, $663,499 in usage charges, and $461,569 of other charges for scheduling penalties (7 percent), OPAS Violations (12 percent), Daily Imbalance Charges During Critical Periods (16 percent), Unauthorized Overrun (zero), Daily Variance (3 percent), and Balancing Cash Out (49 percent), after refunds and before NSP and T-1 credits. Gross Transwestern charges included $6,592,643 in demand charges and $168,524 in usage charges.

UNS GAS POLICIES AND PROCEDURES

Q. Which company policies and procedures did you review?

A. My review included annual copies for multiple years of the *UniSource Energy Corporation Energy Risk Control Policies Manual* and the *UNS Gas, Inc. Price Stabilization Policy.* I reviewed the PGA financial accounting policy, Energy Settlement PGA Bank Procedures, and the *UniSource Energy Corporation Code of Ethics and Principles of Business Conduct.*

Q. Do you have any other recommended changes to policies and procedures?

A. Yes, I have several, in addition to the ones previously discussed.

[6] NSP and T-1 debits and credits are deducted from gross pipeline charges, not flowing through to the PGA.

Q. What are they and the rationales behind them?

A. I recommend that the policies and procedures be updated at least annually to reflect current practices and procedures. A number of discrepancies were noted between the *UNS Gas Price Stabilization Policy* and trading room practices. I provided a list of discrepancies to TEP management. While current practices may be reasonable, the policy should always match practices. This is important to ensure the proper checks and balances are in place and are being adhered to. The discrepancies appear related to the fact that the *UNS Gas Inc. Price Stabilization Policy* virtually did not change for a number of years, even though operating practices evolved somewhat over the same time. Also, I recommend that all parties involved with gas procurement should acknowledge the policy by signing annually, including Gas Scheduling, Transportation Contracts, Risk Management, and Risk Control, not just the traders. This will help ensure that the roles of all parties are accurately reflected. Finally, I recommend that a single person be designated as the 'policy owner' to ensure, on an annual basis, that the policy is accurate before it is approved by the Corporate Risk Management Committee. A commercial person that is familiar with all aspects of gas procurement would be best.

ONSITE VISIT

Q. Did you make an on-site visit as requested?

A. Yes. I made an on-site visit to TEP Wholesale Department for three days on April 13-15, 2009 to interview personnel and gather additional information. My interviews included TEP personnel and management, and personnel from some corporate departments of UniSource, including Risk Control, Financial Forecasting, Internal Audit, and Energy Settlements. On April 14, 2009, I personally witnessed Day Ahead gas purchasing, nominating and scheduling processes. I found their practices to be effective and prudent, including bidder award. The next day gas purchasing decisions are made and executed by

a single individual, the Portfolio Manager of natural gas for TEP, UNS Gas and UNS Electric, Mr. Ray Robey.

Q. How does Mr. Robey make the decision about which supplier to purchase from?

A. UNS Gas has master ISDA agreements with [redacted] gas suppliers, with [redacted] others in the administrative queue to be finalized, and NAESB agreements with [redacted] additional entities, with [redacted] more in the queue. To purchase Day Ahead gas, Mr. Robey canvasses the market for the best offers through an electronic trading house (Intercontinental Exchange), instant messaging, telephone, and a voice box that connects directly to a broker. However, he can only execute with those suppliers for which there are pre-existing master agreements and credit arrangements. This is one of the reasons why it's important for a company to maintain a good credit rating and to diversify its supplier base, in order to lift the best available offer prices.

Q. How does Mr. Robey make the decision about how much gas to purchase?

A. He generally consults the most recent load forecast and also considers any potential error in the load forecast of recent days which might contribute to the pipeline imbalance and attempts to keep a zero or low imbalance.

TRANSACTION AUDIT

Q. Did you audit any transactions for adherence to policies and procedures?

A. Yes. Six transactions were specifically reviewed for compliance with policies and procedures and found to be compliant. Two contracts were selected from each year in 2006, 2007 and 2008, including the bids related to gas supply for the 2008/2009 winter season where BP Energy Services won the right to supply the majority of the gas.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RITA R. BEALE

EDUCATIONAL BACKGROUND

Master of Science	Mineral Economics, Colorado School of Mines, 1987
Bachelor of Science	Geology, Rider University, 1984 (Phi Beta Kappa Honor Key)

PROFESSIONAL EXPERIENCE

Current Position

ENERGY VENTURES ANALYSIS, INC. – Arlington, VA

Principal
Ms. Beale joined EVA in 2007 as co-head of the oil and natural gas practice, with additional specialization in electricity.

Prior Experience

WEST HILL GROUP - Aledo, TX **2005 - 2007**

Principal

- Analyzed investment costs of new NGL processing plant of ~$100 million and evaluated whether to use gas compressors or electric motors.
- Negotiated ERCOT power supply contract and structured heat rate terms to meet client's risk management objectives.
- Provided hedge strategy consultation and market timing to end-users.

FIRST CHOICE POWER LP - Fort Worth, TX **2003 - 2005**

Vice President, Energy Services
Executive officer with P&L responsibility for physical ERCOT power and financial natural gas. General management & leadership of five areas: (a) wholesale supply and portfolio management (b) customer deal pricing (c) back office settlement of wholesale supply contracts and preparation of General Ledger accounting entries (d) electric load forecasting for >200,000 customers (e) ERCOT market operations/protocols. Served on Risk Management Committee & Sarbanes Oxley Disclosure Committee.

- Working closely with C-level management, turned company around from negative commodity position. Stayed through successful sale of company.

- Acted as de-facto Director of Portfolio managing all commodity & operational risk of energy, ancillaries, and renewable energy as fixed price, basis, and option positions. Led multi-discipline team that structured & negotiated $800 million in power supply deals that enabled FCP to survive and restart customer acquisition.
- Help set up Special Purpose Entity (bankruptcy remote) to enhance company creditworthiness and serve as collateral for power supply contracts. Administered front office policies and practices to ensure adherence to risk policies and other contractual covenants.
- Managed staff of 22 with operating budget of ~$2 million. Responsible for annual and quarterly department forecasts and updates.

IDACORP ENERGY LP – Boise, ID **2002 - 2003**

Vice President & General Manager, Electric Power

P&L responsibility for physical & financial wholesale power trading, origination, and market analysis reporting to the President.

- Responsible for portfolio management of wholesale power book and exposures in fixed price, basis, index, and option positions in the western USA. Ensured trading compliance with all portfolio VaR limits and risk policies.
- Positions included deal flow from large commercial & industrial customers and a large number of power transmission contracts modeled as options.
- Activities included portfolio (re) valuation and resolution of regulatory & legal contractual issues.
- Led external sale of commodity book through bid process. Locked mark-to-market value to flatten book prior to sale. Reduced department by half to staff of 20 to meet BOD obligations until sale of book.

ANDERSEN LLP – Chicago, IL **1998 - 2002**

Senior Manager, Financial & Commodity Risk Consulting

Scoped, priced, and executed engagements as project manager. Fostered relationships with clients to spearhead key initiatives including business strategy, process reengineering and Sarbanes Oxley controls, risk management, and financial valuation.

- Responsibilities included developing and executing business plans, hiring and developing consulting personnel, quality assurance, and client satisfaction.

EL PASO ENERGY MARKETING – Houston, TX **1996 - 1998**

Manager, Natural Gas Storage Trading

P&L responsibility for financial & physical optimization of natural gas withdrawals and injections based on embedded optionality. Portfolio included proprietary leases and client asset management on 18 different pipelines in the East, US Gulf, Texas, Midwest, & Canada.

- Established new storage department from inception into operation.
- Developed & implemented rigorous market-based arbitrage pricing tools to determine schedules and extract maximum value in daily & forward markets.

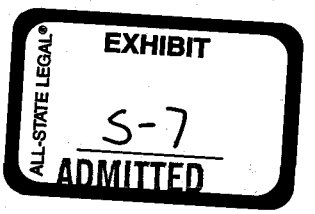
Manager, Structured Transactions
Set-up initial structure desk and related processes to value & price complex physical natural gas transactions that included energy, storage, and pipeline capacity.

- Administered centralized pricing & execution for sales reps at six remote locations.
- Marketed OTC derivatives to personal book of customers.

ENERGY COMMODITY ANALYST

GOLDMAN, SACHS & CO - New York, NY	**1993 - 1995**
LEHMAN BROTHERS - New York, NY	**1988 - 1993**

For oil and natural gas, conducted fundamental research on global supply, demand, storage, and relevant trends impacting prices. Published price forecasts and trading recommendations for hedgers and specs. Produced research reports, led client teleconference calls, spoke at client conferences, and attended OPEC meetings as industry observer.



BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571

SURREBUTTAL

TESTIMONY

OF

RITA R. BEALE

ON BEHALF OF THE STAFF OF THE

ARIZONA CORPORATION COMMISSION

JULY 29, 2009

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UNS GAS, INC.
DOCKET NO. G-04204A-08-0571

In April and May 2008, I conducted a prudency review of the gas procurement operations of UNS Gas Inc. ("UNS Gas") My testimony focused on the period from January 2006 to June 2008, with nine findings and also ten recommendations for the Commissioners to consider. In his rebuttal testimony, Mr. Hutchens accepted and concurred with all of my ten recommendations, however his additional comments suggested that he did not fully understand several recommendations. I felt it was necessary to clarify the nature of recommendations numbered 1, 2, 5 and 6. My ten recommendations are:

(1) UNS Gas should conduct a thorough analysis of excess interstate pipeline capacity that could be currently optimized through Asset Management Arrangements (AMA).

(2) If excess pipeline capacity is available, UNS Gas should have Tucson Electric Power ("TEP"), seek potential counterparties on UNS Gas' behalf, at least annually, to optimize all of its excess capacity on both Transwestern and also on El Paso Pipeline, although not at the expense of incurring a net increase in El Paso charges and penalties.

(3) UNS Gas should be required to supplement the information filed monthly to the Commission to tie out and support all entries of the Purchased Gas Adjustor Bank Balance, and specifically to include the *UNS Gas Core Market/ System Supply Imbalance Report* which finalizes tie-out of the commodity balances by pipeline.

(4) To ensure accuracy of the PGA filings, personnel from the Energy Settlements and Billing Department should receive additional training in the operating practices and terminology used by TEP Wholesale Department for gas procurement.

(5) The *UNS Gas Inc. Price Stabilization Policy* should be changed to require consideration of purchases during the three excluded months of August, September and October. Automatically excluding these months created missed opportunities to buy lower-priced gas during 2006, 2007 and 2008.

(6) To increase its hedge documentation, UNS Gas should create a record indicating the months that management decides to deviate from a ratable purchasing pattern,[1] even if it as simple as using a checklist denoting 'management decided not to hedge'.

(7) The *UNS Gas Inc. Price Stabilization Policy* should also be amended for any changes to gas purchasing strategy changes effective September 2008, when TEP took over gas procurement.

(8) The *UNS Gas Inc. Price Stabilization Policy* must be updated at least annually to reflect current practices and procedures.

(9) All parties involved with gas procurement should acknowledge the *UNS Gas Inc. Price Stabilization Policy* by signing annually, including Gas Scheduling, Transportation Contracts, Risk Management, and Risk Control; not just the traders.

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[1] The *UNS Gas Inc. Price Stabilization Policy* essentially sets a non-discretionary portion of forecasted gas load (minimum 45 percent) to be hedged with fixed price instruments at ratable quantities of 1/27th over 27 different months leading up to the physical flow month, excluding August, September and October.

(10) A single person should be assigned as the 'policy owner' of the *UNS Gas Inc. Price Stabilization Policy* to ensure, on an annual basis, that the policy is accurate before it is approved by the Corporate Risk Management Committee.

INTRODUCTION

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

A. My name is Rita Regina Beale. I am a consultant employed with Energy Ventures Analysis, Inc. ("EVA"). My business address is 1901 N. Moore Street, Suite 1200, Arlington, VA 22209-1706.

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my Surrebuttal is to respond to the Rebuttal Testimony of David Hutchens of UNS Gas Corporation ("UNS" or "Company") as it relates to my Direct Testimony.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or Commission") Utilities Division Staff.

Q. How is your testimony organized?

A. I have additional comments to David Hutchen's response to my recommendations numbered 1, 2, 5 and 6.

SUMMARY OF SURREBUTTAL

Q. Please summarize the relevant UNS Rebuttal Testimony.

A. In his rebuttal testimony, Mr. Hutchens accepted and concurred with all of my recommendations, however his additional explanations suggested to me that he did not fully understand my recommendations, and I felt it was necessary to clarify the nature of the recommendations.

SURREBUTTAL TESTIMONY

Q. What would you like to clarify for recommendations numbers 1 & 2?

A. UNS Gas seems to be doing a fine job on offering excess capacity on the brand new Transwestern Pipeline in the form of Asset Management Arrangements ("AMA"). However my recommendation was to extend similar efforts to optimize all excess capacity on existing El Paso Pipeline and Transwestern Pipeline contracts, as well. Mr. Hutchens discussed the AMA for the brand new Transwestern Pipeline capacity and did not acknowledge the other existing contracts.

Q. What would you like to clarify for recommendation number 5?

A. UNS Gas' current policy is ineffective and causes rate payers to miss the opportunity to buy low price gas. My recommendation is to formally change the hedge policy and now require non-discretionary purchases in the months of August, September, and October. As with other months of the year, the portfolio manager should continue to have the option of seeking management approval not to execute the non-discretionary hedges in those months. Mr. Hutchens stated that UNS Gas would consider evaluating opportunities during the traditional hurricane months, which is a different concept.

Q. What would you like to clarify for recommendation number 6?

A. For its discretionary hedges, a review of all existing hedge documentation suggests that UNS seems to be doing a good job of documenting Risk Management Committee approvals by email, but conversely, a fairly poor job of documenting changes to its non-discretionary hedges. In the system of record from which transactions and trade patterns are analyzed, there is no notation of whether a transaction is discretionary or non-discretionary, so perhaps such notation could be accommodated in the system. Sorting all hedge transactions by either a flow month, or conversely by trade execution date, leaves

nothing in the record to explain all of the variations from an expected pattern, of which there are many. There also is no apparent tie to the forecasted volumes. Exhibit 1 is offered as an example of what the hedge documentation might look like.

Exhibit 1:

Hedge Record

Physical Flow Forecast, Jan 2010

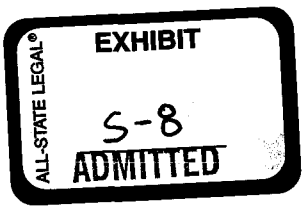
Trade Execution Month	2,346,377 50% Target 1,173,189 Amount Hedged	Cumulative Hedge	Notes
Dec-06	32,589	32,589	Done. 1/36 of remaining
Jan-07	32,589	65,177	Done. 1/35 of remaining
Feb-07	32,589	97,766	Done. 1/34 of remaining
Mar-07	80,000	177,766	RMC approval for higher volume
Apr-07	32,125	209,891	Done, 1/32 of remaining
May-07	0	209,891	RMC approval to wait
Jun-07	33,196	243,087	Done. 1/30 of remaining
Jul-07	33,196	276,283	Done. 1/29 of remaining
Aug-07	33,196	309,480	Done. 1/28 of remaining
Sep-07	33,196	342,676	Done. 1/27 of remaining
Oct-07	33,196	375,872	Done. 1/26 of remaining
Nov-07	33,196	409,068	Done. 1/25 of remaining
Dec-07	28,063	437,132	Corporate forecast changed to 2,100,000
Jan-08	28,063	465,195	Done. 1/23 of remaining
Feb-08	28,063	493,258	Done. 1/22 of remaining
Mar-08	28,063	521,322	Done. 1/24 of remaining
Apr-08	28,063	549,385	Done. 1/25 of remaining
May-08	60,000	609,385	RMC approval for higher volume
Jun-08	60,000	669,385	RMC approval for higher volume
Jul-08	60,000	729,385	RMC approval for higher volume
Aug-08	-	729,385	RMC approval to wait
Sep-08	-	729,385	RMC approval to wait
Oct-08	-	729,385	RMC approval to wait
Nov-08	-	729,385	RMC approval to wait
Dec-08	29,434	758,819	Done. 1/12 of remaining
Jan-09	29,434	788,252	Done. 1/11 of remaining
Feb-09	29,434	817,686	Done. 1/10 of remaining
Mar-09	60,000	877,686	RMC approval for higher volume
Apr-09	60,000	937,686	RMC approval for higher volume
May-09	60,000	997,686	RMC approval for higher volume
Jun-09	60,000	1,057,686	RMC approval for higher volume
Jul-09	60,000	1,117,686	RMC approval for higher volume
Aug-09	50,000	1,167,686	RMC approval for higher volume
Sep-09		=56% of Forecasted Load	
Oct-09			
Nov-09			Hedge must be completed

Q. Please summarize your additional findings.

A. My findings are that UNS Gas concurred with my ten recommendations and may have needed some additional clarification on numbers 1, 2, 5 and 6 provided in this surrebuttal.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.



BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
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Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. G-04204A-08-0571

DIRECT

TESTIMONY

OF

JUAN C. MANRIQUE

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 08, 2009

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EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NO. G-04204A-08-0571

On November 7, 2008, UNS Gas, Inc. filed and application with the Commission for rate relief. The purpose of this testimony by Staff witness Juan C. Manrique is to present Staff's position on proposed changes to by the Company to its Rules and Regulations. Staff concludes that the changes proposed by UNS Gas, Inc. are prudent and recommends that they be authorized.

INTRODUCTION

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

A. My name is Juan Manrique. I am a Public Utilities Analyst 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 a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I provide recommendations to the Commission on financings and certificates of convenience and necessity. I also perform studies to estimate the cost of capital for utilities that are seeking rate relief.

Q. Please describe your educational background and professional experience.

A. In 2005, I graduated from Arizona State University, receiving a Bachelor of Science degree in Finance. My course of studies included classes in corporate and international finance, investments, accounting, statistics, and economics. I began employment as a Staff Public Utilities Analyst in October 2008.

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

A. I will address the Rules and Regulations to be recommended for UNS Gas, Inc. ("UNS" or "Company").

ESTABLISHMENT OF SERVICE

Q. Has UNS revised its Establishment of Service Rules and Regulations as part of the current rate case?

A. Yes. UNS added language to its Establishment of Service section regarding service re-establishments at the same location. The proposed change states "For service re-

establishments at the same location where the same Customer has ordered a service disconnect within the preceding twelve (12) month period, such returning Customer in addition to the service re-establishment charge, shall pay the sum of the applicable monthly Customer Charges that would have accrued had the Customer not ordered the disconnect."

Q. What is Staff's opinion on this change?

A. Staff notes that while this is a change under "Section 3, Establishment of Service" of the Company's Rules and Regulations, this issue is in conformance with "Section 2, Definitions, No. 49" which defines the Service Re-establishment Charge. Therefore Staff agrees with this change.

Q. Are there any other changes to Section 3, Establishment of Service?

A. Yes. Section 3 also establishes that "For service reconnections when due to the behavior of the Customer (i.e., nonpayment, failure to comply with the Company's Pricing Plans) it has been necessary for the Company to discontinue service utilizing other than the usual operating procedures prior to reconnection of gas service each time the gas is disconnected, in addition to the service reconnection charge set forth in the Statement of Additional Charges, the Customer shall pay the sum of the applicable monthly Customer Charges that would have accrued had the Customer not been disconnected within the preceding twelve (12) month period." This change mirrors the Service Re-establishment fee and therefore Staff agrees with this change as well.

Q. Are there any other changes of consequence proposed by the Company in the current rate case?

A. No. There are minor changes to the language employed but no substantive changes have been proposed. Staff concludes that all changes proposed by the Company be authorized.

Q. Does this conclude your direct testimony?

A. Yes, it does.

JUAN C. MANRIQUE

EXPERIENCE CHRISTENSEN & ASSOCIATES

03/08 – PRESENT *ASSOCIATE*

SCOTTSDALE, AZ

- Initiate investor relations program by meeting with new clients and deciding an appropriate goal and strategy to encourage new and further investment designed to increase share price
- Use proprietary database to target and profile potential investors
- Organize meetings between client and targets to facilitate investment
- Conduct post-meeting interviews with investors and use feedback to generate a perception study report and suggested course of action for client

RYLAND MORTGAGE

01/06 – 11/07 *MANAGEMENT TRAINEE*

DALLAS, TX

- Gained experience in all aspects of mortgage loan processing, originating and underwriting in a rotational program.
- Maintained a $7MM pipeline by interviewing buyers and originating new home loans
- Analyzed credit reports and advised most clients on strategies for improving credit score
- Received specialized training in managing groups and leading projects
- Led monthly homebuyer education courses explaining the mortgage process and different mortgage products

AMERICAN FUNDS

01/05-12/05 *SHAREHOLDER ACCOUNT REPRESENTATIVE*

SCOTTSDALE, AZ

- Successfully completed new employee training program
- Provided superior service to shareholders and financial advisers by providing quick resolutions to any and all customer inquiries
- Accurately established and maintained mutual fund accounts for thousands of new and existing clients

SHURE INCORPORATED

07/00-01/04 *Customer Service Representative* Niles, IL

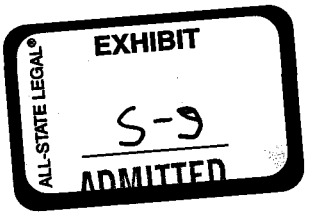
- Created new customer notification process for overnight orders
- Designed a customer service training video for new employees
- Handled all aspects of dealer orders including problem resolution
- Consistently provided high level of service to all external and internal customers by proactively anticipating their needs

Education **Arizona State University, W.P. Carey School of Business** December 2005

Bachelor of Science, Finance

Professional Skills

- Fluent in reading, writing and speaking Spanish
- Talented at organizing workload according to work priorities.
- Proficient with several software applications including Word, Excel, PowerPoint, Access, Outlook and the aptitude to quickly adapt to new ones.



BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
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GARY PIERCE
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IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 08, 2009

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UNS GAS INC.
DOCKET NO. G-04204A-08-0571

My testimony in this proceeding addresses a number of issues related to UNS Gas, Inc.'s ("UNS") purchased gas adjustor ("PGA") mechanism. UNS has proposed to change the interest rate applicable to the PGA mechanism's bank balance. UNS has also suggested several possible proposals related to low income service that would implicate the PGA mechanism. My testimony provides Staff's analysis and recommendations regarding the PGA mechanism and related issues.

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 and natural gas 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 UNS's Purchased Gas Adjustor ("PGA") mechanism and related issues in this case.

Q. Have you reviewed the testimony of UNS Witness Kennton C. Grant in regard to the PGA mechanism?

A. Yes. I have reviewed his testimony and will discuss his proposed change to the interest rate applied to the PGA mechanism's bank balance as part of my testimony.

Q. Have you reviewed the testimony of UNS Witness D. Bentley Erdwurm in regard to the PGA mechanism?

A. Yes. I have reviewed his testimony and will discuss several ideas he has put forth regarding low income ratemaking and possible implications for the PGA mechanism as part of my testimony.

PURCHASED GAS ADJUSTOR

Q. Please discuss the functioning of the PGA mechanism in recent years.

A. At the time the currently-effective PGA mechanism was initially implemented in June 1999, natural gas prices had been relatively low and stable for a number of years. Shortly following implementation, significant changes took place in natural gas markets, leading to higher and more volatile natural gas prices which have made the last five years difficult for regulators, local distribution companies, and consumers of natural gas. Recent years have also provided a stern test of various aspects of the PGA mechanism. Staff believes that in general the PGA mechanism as currently designed and operated has worked well, given the difficult circumstances of recent years. A PGA mechanism by nature determines the manner in which commodity costs are passed through to customers, including such issues as timing and structure of such pass-throughs. In a market where the underlying commodity cost has risen from around $2.50 per mmbtu to $6.00 or so in recent years, any PGA mechanism is going to reflect those higher costs, which will be passed through to customers in some fashion, the primary variance being the manner in which the rising costs are passed along to customers.

No PGA structure can change the underlying fact that natural gas prices and price volatility have for the most part increased dramatically in recent years. Fortunately, natural gas prices as of early 2009 are the lowest they have been due to a number of factors, including growth in domestic production, weaker than expected demand, and weak economic conditions. Thus, the monthly PGA rates charged by UNS Gas and other Arizona local distribution companies ("LDC") have been trending gradually lower in recent months. However, the current low gas prices are not guaranteed to continue very far into the future and history has shown that natural gas prices can spike upward in a short time span.

In general, Staff believes that the current PGA mechanism reasonably balances the interest in shielding customers from price volatility with the competing desire to at least to some extent send a price signal to customers regarding the changing level of the underlying commodity costs.

Q. Has the Commission addressed UNS's PGA mechanism recently?

A. Yes. The PGA mechanism was considered in UNS' rate case that resulted in Decision Number 70011 (November 27, 2007). In that recent case the Commission made a number of changes to UNS' PGA mechanism, including setting the base cost of gas to zero, expanding the bandwidth on the monthly PGA rate, eliminating the bank balance threshold on undercollections, increasing the bank balance threshold on overcollections, and retaining the existing interest rate for the PGA bank balance. Staff is not proposing further change in this case to any of these matters. Staff believes that further time is needed to see how these recent changes impact the function of the PGA mechanism. Additionally, Staff has not seen any compelling evidence that further change is needed in relation to any of these issues.

Q. UNS has proposed changes to the interest rate to be applied to the PGA bank balance. Please describe UNS's proposed change.

A. UNS Witness Grant is proposing to increase the interest rate applied to the PGA bank balance by applying the 3-month London Interbank Offered Rate ("LIBOR") rate plus 1.0 percent to the PGA bank balance each month. This proposal is similar, though simpler, than UNS's proposal in the last rate case where they proposed to apply the LIBOR rate plus 1.5 percent to bank balances up to a certain size, with the portion of the balance exceeding a designated level having UNS's authorized weighted average cost of capital applied as the applicable interest rate.

Q. What was the Commission's finding regarding a UNS' similar interest rate proposal in UNS's recent rate case?

A. The Commission rejected UNS' requested increase to the interest rate. Specifically the Order states that:

> "We agree with Staff that UNS has not presented a sufficient basis for altering the PGA bank balance interest rate that currently exists. As Mr. Gray points out, a similar rate is in effect for Southwest Gas and APS, and we see no reason why UNS should be treated differently from those companies. In addition, granting a higher interest rate could provide a disincentive for the Company to reduce bank balances and could cause it to become less focused on taking all possible measures to reduce the cost of gas for its customers (Id. at 15-16). We therefore adopt Staffs recommendation to retain the current interest rate for UNS's PGA bank balances." (p.80, lines 12-18)

Q. Please discuss the history of interest being applied to PGA bank balances.

A. Until the Commission adopted the banded 12-month rolling average PGA mechanism in October 30, 1998 (Decision Number 61225), the Commission did not provide for the accrual of any interest on over- or under-recovered PGA bank balances. In Decision Number 61225, the Commission approved LDCs, including Citizens Utilities (which subsequently became UNS Gas), to begin applying interest to the PGA bank balances. The approved interest rate at that time was the monthly three month commercial non-financial paper rate, as published by the Federal Reserve. The proposal to apply this interest rate to PGA bank balances was the result of a consensus among working group participants including Staff, the Residential Utility Consumer Office ("RUCO"), Arizona LDCs, and other interested parties. Subsequently, in Decision Number 68600 (March 23, 2006) the Commission approved changing the applicable interest rate for PGA bank

balances to the monthly three month commercial financial paper rate published by the Federal Reserve. The purpose for this change was that the previously approved interest rate was no longer being published by the Federal Reserve on a consistent basis, and the new rate was very similar, if slightly higher on average, than the existing rate prior to Decision Number 68600. And as previously noted, the Commission rejected changing the interest rate in Decision Number 70011 (November 27, 2007).

Q. Please discuss UNS's comparison of the 3-month LIBOR and 3-month commercial financial commercial paper rates.

A. It is unclear what LIBOR rate UNS is proposing to use in this proceeding. Mr. Grant's testimony references a 3-month LIBOR rate published by the Federal Reserve. Staff has not been able to locate a 3-month LIBOR rate on the Federal Reserve's website. Additionally, in response to Staff Data Request BG2-1, UNS provides references to the British Bankers Association ("BBA") website as well as a LIBOR rate published in the Wall Street Journal, but does not provide a reference to any Federal Reserve document or webpage. Further, the rates referenced on the BBA website and in the Wall Street Journal are set on a daily basis, and UNS has not identified how it would apply a daily rate to the monthly PGA calculations. Staff believes that use of a rate published on a monthly basis is more applicable, given that PGA accounting is done on a monthly basis. Whatever rate the Commission may apply in the future to UNS's PGA bank balance, it is important to have a clear and distinct reference point identifying the rate, to avoid any confusion regarding what interest rate is applicable.

Q. Please provide Staff's perspective on the interest rate to be applied to the PGA bank balance.

A. Staff would reiterate the points it made regarding this issue in UNS' recent rate case. Specifically, when the Commission first granted interest on the PGA bank balance in 1999, it was clear that the interest rate being adopted at that time was not equal to any LDC's expected costs of borrowing. Additionally, in rate cases since that time, the Commission has not adopted an interest rate that was considered to be equivalent to the LDC's cost of borrowing. In a recent Southwest Gas rate case (Decision Number 68487, dated February 23, 2006), the Commission adopted an interest rate for Southwest Gas, the one-year nominal Treasury constant maturities rate, that is similar to the current interest rate for UNS. Additionally, the Commission adopted the same interest rate for Southwest Gas as for Arizona Public Service. UNS has not demonstrated that it is so different from other Arizona utilities that it somehow warrants a higher interest component.

An additional aspect of this discussion is that the Company's cost of borrowing is likely to change over time, so it is unlikely that there is any simple method of setting an interest rate to specifically track UNS's exact cost of borrowing, even if the Commission wished to do so.

Also, as a general principle, to the extent an LDC receives an interest rate on the PGA balance that might be expected to fully compensate it for the costs of borrowing (or even possibly overcompensate), there could be a concern that the LDC would become less concerned with reducing the PGA bank balance and could become less focused on taking all steps necessary to reduce the cost of natural gas for its consumers.

Further, as was noted in 1999 when the Commission began allowing interest to be collected on PGA bank balances, the higher the interest rate the Commission grants for PGA bank balances, the more the resulting interest will make the PGA bank balance more volatile. The level of such additional volatility is not enormous, but the cumulative effect can be noticeable over time.

Q. What is Staff's recommendation regarding UNS's proposal to change the interest rate applied to the PGA bank balance?

A. While it is difficult to identify the specific rate or manner in which UNS would apply its proposed rate, fundamentally Staff does not believe circumstances have changed significantly since the Commission chose to retain the existing interest rate for the PGA bank balance in UNS's last general rate case order in November 2007. Staff believes that continued application of the 3-month commercial financial paper rate to UNS's PGA bank balance is reasonable and the Commission should not change to a different interest rate absent a compelling reason to do so, which UNS has not provided. Therefore Staff recommends that no change be made to the interest rate applied to the PGA bank balance.

Q. Please describe UNS' suggestions regarding low income rates and the PGA mechanism.

A. In UNS Witness D. Bentley Erdwurm's Direct Testimony he indicates the Company supports efforts to provide a discount on the commodity cost of gas to Customer Assistance Residential Energy Support ("CARES") customers and/or establish some sort of gas cost cap for CARES customers. Mr. Erdwurm further suggests that discounted amounts could be recovered through UNS's PGA mechanism. Mr. Erdwurm suggests the possibility of a working group considering these ideas, but does not provide details as to how the proposals would work.

Q. Please provide Staff's perspective on these proposals.

A. Staff is sympathetic to UNS's goal of providing greater assistance to low income customers and has worked in many rate cases over the years to improve the level of assistance provided to low income customers. However, Staff does not believe that proposals which would alter the way the PGA mechanism operates are the right venue to pursue additional low income customer relief. The Commission has always been careful to only pass through the PGA mechanism the cost of the commodity and the transportation costs to deliver the commodity as well as an interest component in recent years. For a variety of electric and natural gas utilities in Arizona, the cost of discounts provided to low income customers has either been dealt with as part of overall costs in a rate case, or passed through a separate adjustor mechanism that has been specifically designed to pass such costs through, as has been the case for Southwest Gas for many years. Introduction of low income discount costs to the PGA mechanism would unbalance the PGA mechanism, complicate the tracking of costs and recoveries through the PGA mechanism, and would tend to skew it toward developing undercollected PGA bank balances over time. If greater discounts and/or other protections are implemented for low income customers, they should be provided via means other than through the PGA mechanism. The PGA mechanism should continue, as it has in the past, to only reflect the cost of the natural gas commodity and interstate transportation costs, as well as an interest component.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. My testimony includes the following recommendations:

1. The interest rate applicable to the PGA bank balance should not be changed in this proceeding.

2. To the extent the Commission further extends rate relief to low income customers in this proceeding, the Commission should not accomplish this goal by altering the cost of gas component of rates or allowing recovery of such costs through the PGA mechanism.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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.

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.

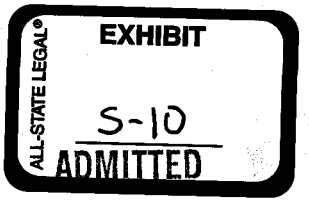
Staff Report on Semstream Arizona Propane, Payson Division issues, Arizona Corporation Commission, June 6, 2008.

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	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



BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571

SURREBUTTAL

TESTIMONY

OF

ROBERT G. GRAY

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 29, 2009

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UNS GAS INC.
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My surrebuttal testimony in this proceeding addresses UNS Gas Inc.' (UNS) Witness Kentton Grant's rebuttal testimony regarding the application of interest to the purchased gas adjustor ("PGA") bank balance.

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 in the Utilities Division. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Are you the same Robert Gray that filed direct testimony in this proceeding?

A. Yes.

Q. What is the scope of this surrebuttal testimony?

A. My surrebuttal testimony provides Staff's comments on UNS Gas Inc. ("UNS") Witness Grant's rebuttal testimony regarding interest applied to the Purchased Gas Adjustor ("PGA") bank balance.

PURCHASED GAS ADJUSTOR

Q. Please comment on Mr. Grant's rebuttal testimony.

A. Mr. Grant's rebuttal testimony provides some clarification regarding possible sources for the London Interbank Offered Rate interest rate which UNS has proposed for adoption in this proceeding as well as discussing the possible application of several different interest rates to the PGA bank balance.

Q. Having reviewed Mr. Grant's rebuttal testimony, are there any changes to Staff's recommendations regarding the interest rate to be applied to the PGA bank balance?

A. No. For the reasons contained in Staff's direct testimony, Staff continues to believe the current interest rate should be retained.

Q. Do you have any further comments regarding the application of interest to the PGA bank balance?

A. Yes. Mr. Grant's testimony focuses on the cost of borrowing for UNS in regard to the PGA bank balance, but in practice the PGA bank balance can be, and has been, both under-recovered and over-recovered at various times in its history. Thus the interest rate is currently, and should be in the future, applied symmetrically to cases where UNS is owed money by the ratepayers and where ratepayers are owed money by UNS.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
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IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571

DIRECT

TESTIMONY

OF

CORKY HANSON

ASSISTANT SUPERVISOR

SAFETY DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 08, 2009

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EXECUTIVE SUMMARY
UNS GAS, INC.
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Mr. Hanson's Direct Testimony addresses the UNS Gas, Inc. list of capital improvements and new construction to determine whether the projects were used and are useful.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Corky Hanson. My business address is 2200 N. Central Avenue, Phoenix.

Q. What is your current position and how long have you been employed by the Arizona Corporation Commission?

A. I am the Assistant Supervisor of the Pipeline Safety Section; I have been employed by the Arizona Corporation Commission ("Commission") for over 17 years.

Q. Please describe briefly your duties as a Assistant Supervisor.

A. As Assistant Supervisor, I am responsible for the following:

- Assist Supervisor in the management of the pipeline safety program.
- Review inspectors' reports for accuracy and completeness.
- Under the direction of the Supervisor, schedule activities and tasks and assign personnel to accomplish these projects.
- Assist Supervisor in development and updating of pipeline safety policies and procedures.
- Assume the role of Interim Supervisor in the absence of the Supervisor.

Q. Have you previously testified?

A. Yes, I have previously testified on behalf of the Commission in seven cases.

Q. What is the purpose of your testimony in these proceedings?

A. The purpose of my testimony is to address the UNS Gas, Inc. list of capital improvements and new construction to determine whether the projects were used and are useful.

ANALYSIS

Q. Does the Pipeline Safety Section have any concerns regarding the used and useful analysis of the list that would affect this rate case?

A. No.

Q. How were you able to determine the used and usefulness of the list?

A. I reviewed UNS Gas, Inc.'s response to Staff's 3rd set of data requests dated March 27, 2009. This data has a list of each project with a date and a map that identify the purpose of each project. Also, Gary Smith V.P. and General Manager of Gas Operation for UNS Gas, Inc. left me with his cell phone number to call him if I had any questions during the process. I took advantage of this opportunity on several occasions.

Q. Were there any non-compliance items noted during the 2009 comprehensive audit?

A. No.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

CORKY HANSON

- Prior to working for the Office of Pipeline Safety (OPS), Corky was the Operation Supervisor at Black Mountain Gas Company (BMG) for thirteen years. He was responsible for designing and engineering new pipeline systems, repair of existing pipelines, operation, maintenance and emergency response. At BMG, Corky had pipeline industry training in leak survey, cathodic protection, pressure regulation/relief devices, odorization, valve maintenance, construction of a pipeline and emergency response. Corky authored the original "Operation, Maintenance and Emergency Manual" for BMG.

- His other experience includes four years as a contractor employee doing construction for the local gas and water utility companies; two years in the U S Army (Combat Engineers).

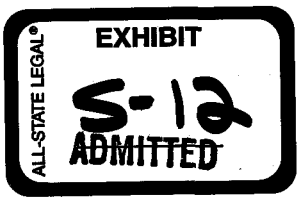
- Corky has worked for OPS since May 4, 1992 where he has conducted numerous pipeline safety audits on both intrastate and interstate pipeline operators and incident investigations. Corky was a member of the Federal/State Operator Qualification Committee and The American Society of Mechanical Engineers (B31Q) Committee in developing a standard for qualification of pipeline personnel. He is also a current member of the Common Ground Alliance, a nonprofit organization dedicated to promoting effective damage prevention practices for underground utilities. Corky has been connected with the pipeline industry since 1974. On March 9, 2009 Corky was promoted to Pipeline Safety Assistant Supervisor.

- **Federal Training Courses:**

  Gas Pressure Regulation and Overpressure Protection Course
  Safety Evaluation of Pipeline Corrosion Control Systems I
  Safety Evaluation of Gas Pipeline Systems
  Pipeline Failure Investigation Techniques
  Pipeline Safety Regulation Application and Compliance Procedures
  Joining of Pipeline Materials
  Safety Evaluation of Pipeline Corrosion Control Systems II
  Safety Evaluation of Hazardous Liquid Pipeline Systems
  Liquefied Natural Gas Safety Technology and Inspection
  Operator Qualification
  Pipeline Reliability Assessment
  Integrity Management Courses
  General Pipeline Safety Awareness Course (Hazwoper)

ARIZONA CORPORATION COMMISSION – Office of Pipeline Safety

- New Employee Training (6 weeks)
- Master Meter Training Class
- Liquefied Petroleum Gas
- Welding Procedures and Visual Examination of Welds
- Incident Investigations
- Computer Science Classes



BEFORE THE ARIZONA CORPORATION COMMISSION

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BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571

DIRECT

TESTIMONY

OF

THOMAS FISH

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 08, 2009

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Accompanying the Direct Testimony of Thomas H. Fish, Ph.D.

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EXECUTIVE SUMMARY
UNS GAS INC.
DOCKET NO. G-04204A-08-0571

Based upon my review of the Company's filing and its books and records, I have determined that the Company has an operating income deficiency of $2,077,601 and I recommend that the Company be authorized a base rate increase of $3,395,423. This is based on an original cost rate base of $178,509,369, RCND rate base of $324,538,937, and fair value rate base of $251,524,153. The proposed rates are designed to provide the Company the opportunity to recover its cost of providing service.

INTRODUCTION

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

A. My name is Thomas H. Fish. I am President of Ariadair Economics Group. My business address is 1020 Fredericksburg Rd., Excelsior Springs, MO 64024.

Q. What does Ariadair Economics Group do?

A. Ariadair Economics Group provides expert witness and consulting services in administrative and judicial litigation proceedings.

Q. Please describe your educational background.

A. I hold a B.A. (1968) degree in Economics from University of Missouri at Kansas City, a M.A. (1970) degree in Economics from Central Missouri State University, and a Ph.D. (1972) degree in Economics, with minor areas of study in Finance and Marketing, from University of Arkansas.

Q. Please describe your professional experience.

A. I have provided expert witness and consulting services in Economics, Finance, Utility Regulation, Industrial Organization, and related areas in administrative and judicial litigation proceedings for over thirty years. I have also taught graduate and undergraduate college classes in Economics, Finance, Quantitative Methods, Financial Accounting, Managerial Accounting, Cost Accounting, Management and related classes. My resume is attached as Attachment THF – 1.

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

A. I have been retained by the Utilities Division of the Arizona Corporation Commission ("Staff") to review the rate application of UNS Gas, Inc. ("Company" or "UNS Gas") and

to address the following issues: Revenue Requirement and certain adjustments to Revenue Requirement, Original Cost, Reconstruction Cost New, and Fair Value Rate Base, Cost of Service, Customer Class Risk and Rate Design. I have performed an analysis and evaluation of those issues and will make recommendations regarding them.

Q. Have you reviewed the Company's application for rate relief?

A. Yes. I have reviewed, analyzed and evaluated the Company's application, its rate base and revenue pro forma adjustments, its work papers in support of its pro forma adjustments, and its response to a series of data requests submitted by Staff.

Q. Have you reached any conclusions as a result of your review?

A. Yes.

Q. Have you prepared Schedules in support of your testimony?

A. Yes, I have prepared an attachment, Attachment THF-2, consisting of several Schedules, identified as Schedules THF – A1 through THF – RD6 in support of my testimony. The A, B, and C Schedules are associated with the revenue requirement part of my testimony and the RD Schedules are associated with the Cost of Service/Rate Design part of my testimony.

Q. Would you please describe the A Schedules?

A. Yes. The A Schedules present a summary of the Company's revenue deficiency and gross-up factor. Schedule THF – A1 shows the Company's and Staff's Original Cost Rate Base, Reconstruction Cost New Rate Base, and Fair Value Rate Base and the required operating revenue necessary for the Company to recover its prudent costs of providing

service including a fair return on capital. These Staff values are based on the values presented in the B and C Schedules.

Q. Would you explain the three different rate base values that you identify?

A. Yes. The Original Cost Rate Base is the net value of the plant and equipment used and useful in providing natural gas distribution services by the Company. It is measured in dollars actually invested in net plant and equipment. Reconstructed Cost New Depreciated Rate Base is the estimated net value (cost) of the Company's Original Cost Rate Base if that Rate Base had to be reconstructed using the value of today's dollars. The Fair Value Rate Base is the average of the Original Cost Rate Base and Reconstructed Cost New Depreciated Rate Base. The Commission has adopted this procedure for deriving Fair Value Rate Base in other regulatory proceedings.

Q. Please describe the B Schedules.

A. Schedule THF – B1 summarizes the Company's proposed rate base modified to reflect the pro forma adjustments recommended by Staff. Schedule THF-B2 provides a summary of rate base pro forma adjustments. Schedules THF – B3 through THF – B10 are schedules supporting individual pro forma adjustments to rate base. I am sponsoring these Staff adjustments.

Q. Please describe the C Schedules.

A. The C Schedules present a summary of the Company and Staff's Operating Income in Schedule THF – C1, a summary of pro forma income and expense adjustments in Schedule THF – C2, and the remaining C Schedules present support for each of the pro forma adjustments to income or expenses. I am sponsoring these Staff adjustments.

Q. Please describe the RD Schedules.

A. The RD Schedules present support for Staff's Rate Design proposals in this proceeding. Schedule THF – RD1 presents the results of a customer class risk study. Schedule THF-RD2 shows a summary of revenues by customer class and adjusted present rates and proposed rates. Schedule THF – RD3 presents a summary of revenues by rate schedule by adjusted present rates and proposed rates. Schedule THF – RD4 is a summary of Staff recommended Rate Design. Schedule THF – RD5 provides proof of revenue of Staff's proposed rate design. Schedule THF – RD6 provides a bill comparison of present and Staff proposed rates.

Q. Were these Schedules prepared by you or under your supervision?

A. Yes.

REVENUE REQUIREMENT

Q. What revenue increase has UNS Gas requested?

A. UNS Gas requested an increase in revenues of $9,480,876 or about a 6 percent increase to a customer's total bill compared to test year revenue, inclusive of gas costs. According to Company Witness David G. Hutchens the reason for the requested increase is the Company's inability to recover its costs, growth in its service territory, the related increase in capital expenditures and operating costs, as well as increases related to rising material and labor costs.

Q. What does Mr. Hutchens project the number of UNS Gas customers to increase by?

A. On Page 3 of his testimony Mr. Hutchens states that, at the end of the June 30, 2008 Test Year, UNS Gas had a customer base of 145,000 and projected that the number of UNS Gas customers will increase by, on average, 2.5 percent annually.

Q. What revenue increase does Staff recommend?

A. Staff is recommending an increase in gross revenue requirement of $3,395,423 or 2.1 percent over test year including cost of gas.

ADJUSTMENTS TO RATE BASE

Test Year

Q. What test year did the Company use?

A. The Company used a historic test year ending June 30, 2008.

Q. Would you explain the concept of test year?

A. Yes. Regulated utilities such as UNS Gas have the opportunity to recover their prudently incurred cost of providing service, including an opportunity to recover their capital cost. Rates for utility services are set by utility regulators, in this case the Arizona Corporation Commission, so that utilities have an opportunity to recover these prudent costs incurred in the provision of service.

Q. How are prudently incurred cost of providing service determined?

A. The prudently incurred cost of providing service is determined on the basis of a test year. A test year reflects a level of operating revenues and expenses and net plant investment that is representative of normal conditions that are expected to exist when the resulting rates are in effect.

Q. What is required to determine the proper, or representative, level of expense, revenues, and investment?

A. In order to determine the proper, or representative, level of expense, revenues and investment, individual items may be adjusted to reflect their value on an on-going basis.

Some rate base items such as plant in service and accumulated depreciation are based on end of test year levels. Other rate base items such as materials and supplies are based on a test year average level. Certain expense items such as payroll and payroll tax expense are annualized. Expense items that have been incurred, but are not necessary for the provision of service, are removed from the test year. In addition, some expense items, such as legal expense, may occur on ongoing but irregular intervals and require adjusting to normal levels. So some items may require no adjustments, some may require removal, some may require annualization and some may require normalization. After all these adjustments have been made, test year revenue is compared to test year required revenue and, if a shortfall exists, rates are set to provide the utility the opportunity to recover its cost of providing service.

Q. What is the importance of the test year concept and the adjustment process you described above?

A. The adjusting process applied to test year values described above, when conducted properly, will remove (eliminate) all unnecessary transactions, convert possibly erratic and variable transactions to "normal" (normalize) values, and annualize intra-year growth or decay in ongoing values. The result will be a test year that represents the best determination of what the Company's actual net investment in plant and equipment is, what its ongoing expenses can reasonably be expected to be, and what its ongoing income can be expected to be. The Company has the opportunity to recover its prudent expenses of providing service, and these are identified through the adjusting process. It also has the opportunity to recover its prudent capital cost incurred in the provision of service. This is typically done by applying its Weighted Average Cost of Capital ("WACC") to its net rate base. The WACC is calculated by adding the cost of each capital component (debt, common equity, preferred stock, etc.,) times the proportion of each capital component to

the total capital structure together. Adding the Company's expenses to its Capital Cost results in a determination of the Company's revenue requirement. By comparing its revenue requirement with its test year income, a determination is made as to what, if any, revenue deficiency the Company is experiencing. The final step is to design rates so that the new rates for each customer class times the number of customers in each customer class totals the revenue requirement for the test year.

RATE BASE

Q. Are you proposing pro forma adjustments to rate base?

A. Yes. I am proposing four pro forma adjustments to original cost and Reconstructed Cost New Depreciated ("RCND") rate base. These proforma adjustments to rate are: 1) Post Test Year Non-Revenue Plant in Service; 2) Customer Advances Adjustment; 3) Working Capital; and 4) Accumulated Deferred Income Tax ("ADIT"). In addition to these pro forma rate base adjustments I present the results of an analysis and evaluation of the Company's RCND study.

RCND Test Year Calculation Inconsistencies

Q. What is a RCND rate Base?

A. A RCND Rate Base" is defined in A.A.C R14-2-103 as: "An amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments. Contributions and advances in aid of construction, if recorded in the accounts of the public service corporation, shall be increased to a reconstruction new basis."

Q. Would you provide an overview of the process of deriving a RCND rate base?

A. Yes. A RCND study is a point in time measurement, just as an original cost rate base is a point in time measurement. That is, the Company's RCND rate base today most likely will not have the same value as the RCND rate base as of June 30, 2008. Rate Base is a balance sheet idea and balance sheet values are point in time measurements while Income Statement measurements are over time, or flow measurements.

Q What information does the RCN and RCND Rate Base convey?

A The reconstruction cost new ("RCN") rate base provides the gross value of the rate base expressed in today's dollars, and the RCND rate base provides the net value of the rate base expressed in today's dollars. A properly constructed RCND rate base provides an estimate of what the cost would be to reconstruct the existing rate base if it were to be constructed now in today's dollars.

Q. Are there underlying assumptions of RCND studies?

A. Yes. An underlying assumption of RCND studies is that the value of a dollar today, everything else being equal, has more value than a dollar to be received in the future and that a dollar received in the past, everything else being equal, has more value than a dollar to be received now. So the RCND rate base is the value of the rate base when all net dollars invested have the same value regardless of when they were invested. The Original Cost rate base is the value of the rate base when all net dollars have the specific value of those dollars at the time they were spent, that is, they are not adjusted for changes in the value of the dollars. The way to convert current dollars into constant (value) dollars is to create a price (or cost) index for the various types of investments and use the price (or cost) index to convert to constant dollars.

Q. What is a price, or cost, index?

A. Index values provide a relative comparison of prices or costs over time. Price or cost indices have a base period where the index value is 100 and observations away from the base have different values based upon the value of the dollars at those observations. For the RCND rate base derivation we want the base period to be the test year. That is, we want to conduct the analysis in today's dollars because the RCND will show us how much we would have to spend, in today's dollars, to duplicate the original cost rate base. The primary source of index values used in RCND calculations is the Handy-Whitman construction cost index by geographic location and Federal Energy Regulatory Commission ("FERC") account.

Q. Please describe the Handy-Whitman cost indices.

A. The Handy-Whitman indices are index values of plant and equipment costs by FERC account and by region. They have a base value (100) early on in the time series so we need to convert the base from the earlier base period of the series to the end of test year observation. This conversion process is one of dividing the end of test year index by each individual index throughout the series.

Q. Can you give an example of this?

A. Yes. Consider the following example where we are converting the base period from year one in the original index to year four in a new index:

Year	Original index value	Conversion equation	New Index value
1	100.00	(130/100)*100	130.00
2	110.00	(130/110)*100	118.18
3	120.00	(130/120)*100	108.33
4	130.00	(130/130)*100	100.00

Note that the New Index value series has the same relative values between the years as does the Original index value series. However, the indices are measured with respect to year 4 values rather than with respect to year 1 values. The conversion of the base period demonstrated above shown under the column headed "New Index Value" corresponds to the Company's term "Trend Value" used in its RCN study.

This process is simply one of changing the base period but not the relative values of the observations between periods. In the example above, the base period was changed from year one to year four.

Q. Are there any unusual characteristics about values calculated using this technique?

A. Yes. By definition, the RCND values for the test year will be the same as the Original Cost values for the test year.

Q. Can you please briefly explain the difference?

A. Yes. The base period always has an index value of 100 which means that current and constant dollars are the same and the base period for RCND studies for regulatory purposes is the test year. This equality that exists in the base period will only occur at the base period unless the index values for previous, (or subsequent) periods are exactly equal to the original index value. This will rarely, if ever, be the case.

Q. Does this feature of the construction of RCND rate base have implications for determining the validity of the resulting RCND rate base?

A. Yes. If a proforma adjustment to the Original Cost rate base and the corresponding pro forma adjustment to the RCND rate base for an expenditure during the test year have different values, then there was an inconsistency in constructing the RCND rate base.

Q. Please briefly explain the Company's position.

A. Post Test Year Non-Revenue Plant in Service is defined by Mr. Dukes as ". . . investments made prior to the end [but presumably within the test year] of the test year into plant that will not produce additional revenues beyond the test year adjusted amount. These investments were not in service by the end of the test year, but will be in service when rates established in this case go into effect. These are investments in items like transportation equipment, general plant, replacements and relocations of existing facilities." (testimony page 11, lines 5 – 10). So, the investment is clearly not made prior to the test year. The Original Cost rate base pro forma adjustment made by Mr. Dukes for this item is $1,527,588 but the RCND rate base pro forma adjustment made by Mr. Dukes is $2,514,427. The pro forma RCND adjustment is 64.6 percent larger than the pro forma Original Cost adjustment which indicates that an inconsistency was made in constructing the RCND rate base unless a large amount of the investment was made prior to the test year.

Q. Did you evaluate the Company's RCND studies for the 2005 test year and the test year ending June 30, 2008?

A. Yes, I did.

Q. What is the result of your analysis?

A. I noticed that the Handy-Whitman Indices between 2005 and 2008 had barely changed,[1] and that suggests that the major source of change in both the Original Cost and RCND rate bases were from net investments during that period of time. Therefore, the ratio of test year 2005 Original Cost to RCND rate bases should be close to the ratio of June 30, 2008 Original Cost to RCND rate bases. As shown in Schedule THF – B3, the ratios are skewed. The ratio of RCND to Original Cost rate base in test year ending 2005 was 134.1 percent but in test year ending June 30, 2008 the ratio was 176.3 percent. The other ratios shown in Schedule THF – B3 show similar skewed results.

Q. What does this indicate to you?

A. It indicates that inconsistencies were made in conducting the studies.

Q. Did you determine where the inconsistencies were made and what they were?

A. Yes. Inconsistencies were made in both studies. The inconsistencies occurred because the data necessary to perform the studies were not available. Therefore neither study provides the Commission with known and measurable RCND rate base values. Since the fair value rate base is the average of the original cost rate base and the reconstructed cost new rate base, the fair value rate base, like the RCND rate base, is not known and measurable.

An inconsistency was also made in the earlier study when the Company used an incorrect con-version factor index of 435 to calculate its "trend value" FERC account 276, mains. It should have used the 2005 index value of 556.

[1] See Company response to Staff data request 6.1.

Q. Do you have additional support for your determination that the RCND studies are incorrect?

A. Yes. Company Witness Dukes explained that when Citizens' gas assets were acquired by UniSource Inc. the detailed continuing property records of Citizens' gas assets, located in New Orleans, were not available. Also, Arizona law requires that RCND studies must be filed with the application when a regulated Arizona utility files a request for rate relief. In the case of UNS Gas, since the detailed information required for a known and measurable determination of reconstruction cost new rate base was not available when it filed its last rate case, the Company took an extremely conservative approach in deriving its RCND rate base. It did this in its last rate case and kept the value of the RCN down so as not to overstate the RCND rate base value.

Q. Can you show how the Company did this?

A. Yes. Schedule THF-B4 reproduces portions of the Company's work papers associated with the RCND study ending December 31, 2006 and the RCND Study ending June 30, 2008. Column A shows the Handy-Whitman cost index for FERC 276, mains, used by the Company in its December 31, 2006 RCND Study. For the 2005 study, the column is headed "Handy-Whitman line 43, which indicates cast iron mains, but the values in the column are from line 44, steel mains. Note the shaded value 435. This is the cost index for 2004, not 2005. The actual value for 2005 is 556. Columns B and C show the trend values for 1998 through 2005 using the correct and the incorrect cost indices. The correct cost index value is 27.8 percent higher than the value calculated, this is shown in Column D. Column G shows the relative value of the '08 study compared to the '05 study. The '08 values are less than 2 percent greater than the '05 values, if the '05 values had used the correct '05 cost index rather than the '04 index, not the 50 percent plus values represented by the Company in its studies as shown in Schedule THF – B3.

The Handy-Whitman has three indices for FERC account 276, mains. These indices are for cast iron mains, steel mains, and plastic mains. The Company, however, did not have the necessary data that would allow it to use the correct indices and corresponding correct FERC account values. Therefore, it selected the FERC 276 index which had the smallest impact on the study.

Q. Did you conduct a RCND study that corrected for the Company's inconsistencies?

A. No. If I, or any other analyst, attempted to conduct a RCND study using the Company's data, the result would be the same. Without the information regarding the detail of the Company's system, the resulting values could not be considered known and measurable.

Q. What are your recommendations regarding the inconsistencies you found in the Company's RCND study?

A. I recommend that the Commission adopt the RCND study as filed by the Company for this proceeding. The difficulty with the study results from the unavailability of historical detailed Continuing Property Records when Citizens assets were acquired. Over time the impact of the gaps in the older data will diminish and the indices associated with the composition of mains, and other related problems, will tend to go away.

Post Test Year Non-Revenue Producing Plant

Q. Are you proposing a pro forma adjustment to the Company's proposed rate base for Test Year Non-Revenue Producing Plant?

A. Yes.

Q. What pro forma adjustment for Post Test Year Non-Revenue Plant did the Company propose?

A. The Company proposed to increase test year original cost rate base by $1,527, 588 and, as discussed above, increase the RCND rate base by $2,514,427.

Q. What was the reason given by the Company for this pro forma adjustment?

A. According to Company Witness Dallas Dukes:

> "The Commission should allow UNS Gas to recover such costs. The Company has made investments to serve existing customers and will not see any additional revenue directly related to these investments until the time the investments are reflected in rate base within a rate proceeding. The inclusion of post test year non-revenue producing plant in rate base will help the Company to begin recovering its investment and an opportunity at earning a reasonable return in a more equitable time frame. If this current case follows an expected course, new rates will go into effect in December 2009 at the earliest. Based upon the circumstances of this matter in which Staff required at least six months of actual rates billed within the test year – a new rate case could not be filed until October of 2010, with rates most likely not effective until January 2012. So the recovery of and on investments actually made prior to the end of the test year, but not technically in service, will not produce additional revenues until January 2012, in other words, over 3 1/2 years after the investments were made to serve existing customers. (Dukes Direct Testimony, page 11, lines 14 – 26.)

Q. Do you agree with Mr. Dukes' justification for inclusion of Post Test Year Non-Revenue Plant in Rate Base?

A. No. Presumably, the investment was made in order to increase the Company's efficiency/productivity and hence reduce costs of providing service such as maintenance cost. This could result in a mismatch between post-test year revenue and costs. In addition, the Company has a choice as to when it files an application for rate relief. The Company could have waited to file its application so as to include this investment in its test year.

Q. Do you know when the Company made the investments in Post Test Year Non-Revenue Producing Plant in Service it wishes to include in rate base?

A. No. The Company did not provide this information in response to data requests or as part of its work papers in support of its pro forma adjustments.

Customer Advances Adjustment

Q. Are you proposing a pro forma adjustment to the Company's proposed pro forma adjustment to rate base for Customer Advances?

A. Yes.

Q. What pro forma adjustment for Customer Advances did the Company propose?

A. The Company is proposing that the test year reduction to rate base for Customer Advances be "about $600,000."

Q. What is the Company's justification for this pro forma adjustment?

A. Mr. Dukes, page 12, lines 4 – 19, suggests that approximately $600,000 of customer advances have already been spent on projects not included in rate base and the Company,

therefore, does not have those funds available to spend. In addition, since those projects are not reflected in rate base and the contributed capital for those investments is no longer available, the Company's opportunity to earn a reasonable return is reduced by such treatment.

Q. Do you agree with the Company's argument in favor of including $600,000 of customer advances in rate base?

A. No.

Q. Is it your understanding that Arizona utilities have the option to include customer advances in rate base?

A. No.

Working Capital

Q. Are you proposing a pro forma adjustment for Working Capital?

A. Yes.

Q. What are the components of Working Capital?

A. Working Capital is composed of Materials and Supplies, Prepayments, and Cash Working Capital.

Q. Are you proposing any adjustments in these Working Capital components?

A. I am proposing an adjustment only to cash working capital.

Q. What is the basis for your adjustment to Cash Working capital?

A. The Company conducted a lead-lag study to determine its cash working capital requirements. The lead-lag study measures the timing differential between accounts receivable and accounts payable and weights this differential by dollars. My analysis and evaluation of the Company's study suggested that they may have erred in determining lag days for payment of purchased gas. They used 27.89 days for their purchased gas payment lag. However, this included what appears to be an abnormal pay structure for the months of December 2007, January 2008 and February 2008. Payment averaged only 17.83 days for these months, not the normal 35 days. The impact of this early payment appears to have served to shorten the lag period to 27.89 days. Adjusting the Company's analysis for this correction has a significant impact on the Company's cash working capital requirements. This results in an adjustment to working capital requirements of $(1,624,840).

Q. Did you prepare Schedules to support this adjustment?

A. Yes. Schedules THF – 7, THF – B8 and THF – B10 address this issue. Schedule THF – B10 shows the modifications required to the Company's lead lag study to reflect this payments change for natural gas purchases as well as other adjustments required due to this modification. Schedule THF – B8 presents a summary of purchased gas payments lags, and Schedule THF – B7 presents the results of working capital net change.

Accumulated deferred Income Tax ("ADIT")

Q. Are you proposing a pro forma adjustment for Accumulated Deferred Income Tax?

A. Yes.

Q. What is your proposed adjustment?

A. The adjustment to Accumulated Deferred Income Tax is required because of the proforma adjustment to eliminate the Supplemental Executive Retirement Program ("SERP") expense effects income tax. The SERP proforma adjustment is discussed below in the revenue requirements pro forma adjustments discussion.

Q. What is your pro forma adjustment for ADIT?

A. $38,994.

Q. Did you prepare a Schedule in support of this pro forma adjustment?

A. Yes. Schedule THF – B9 shows the calculations required for this pro forma adjustment.

ADJUSTMENTS TO OPERATING INCOME

Q. Do you provide Schedules summarizing your pro forma adjustments to operating income?

A. Yes. Schedule THF – C1 provides a summary of Adjusted Net Operating Income and Schedule THF – C2 provides a summary of pro forma Income Statement Adjustments. The sections below provide a discussion of each of the pro forma adjustments to Operating Income.

Customer Annualization

Q. Did the Company propose a pro forma Customer Annualization adjustment?

A. Yes. The Company proposed a reduction in income of $516,003 to represent its test year reduction in customers. From a review of the work papers associated with the Company's Customer Annualization adjustment, it appears that $302,550 of this amount arises

directly from the Customer Annualization adjustment and the remainder appears to be the adjusted amount from the large industrial customer.

Q. Do you agree with the pro forma Customer Annualization adjustment recommended by the Company?

A. No. Mr. Erdwurm sponsors the pro forma Customer Annualization adjustment using the June, 2008 values. He states on Page 7, lines 5 –9, that "Customer Annualization adjustments should restate the number of test-year bills and volumes to be consistent with (but not necessarily equal to) the number of customers on the system at the end of the test year. Customers should expect a positive customer adjustment on a growing system. A positive customer adjustment typically entails additions to both customers and therms."

Here he appears to recognize that his annualization results are not normal or representative of a test year. He goes on to say, page 8, lines 1 –20, that the Company is experiencing "cyclical, seasonal" fluctuations and customer counts in the summer months tend to be less than in other times of the year. So, if the Commission had adopted the Company's annualization in its last rate case, then the annualization adjustment would have been consistent with year end levels. Essentially, Mr. Erdwurm seems to be saying that a Customer Annualization adjustment based on calendar year end customer levels is more indicative of the Company's actual experience because of a normal summer decline in the number of customers.

Q. Do you agree with Mr. Erdwurm that an end of calendar year Customer Annualization adjustment could be a better representation of ongoing customer and usage levels than a summer month adjustment?

A. Yes.

Q. Do you agree with Mr. Erdwurm's implied recommendation of a "cyclical, seasonal" Customer Annualization procedure?

A. No. The cycle time series component is defined as a wave like fluctuation about the trend with no predictable phase or amplitude, i.e., duration or severity. So attempting to make an annualization adjustment based on the time series cycle component would not work precisely because the cycle component is not predictable and thus not regularly recurring. The seasonal component of a time series, however, is defined as a regularly recurring fluctuation about the trend with predictable phase and amplitude. So it should be possible to determine if there is a seasonal component to the time series of customer counts and usage by customer class and to make adjustments which, in conjunction with the Commission's customary procedure for making annualization adjustments, would be representative of the Company's usage patterns.

As Company Witness Erdwurm suggests, it would be possible to identify a seasonal/cyclical time series component. However, if one were to attempt that then the unpredictable nature of the cyclical component would corrupt the predictable seasonal component so that the resulting value could not be expected to successfully derive a Customer Annualization adjustment.

Q. Did you make a pro forma Customer Annualization adjustment?

A. Yes. My Customer Annualization adjustment calculations are presented in Schedules THF – C3 and THF – C4. I followed Mr. Erdwurm's suggestion that end of calendar year values would be more appropriate than end of test year values for Customer Annualization purposes. Therefore, I based my calculation on December 2007 customer values. Since this is the mid-point (end of December 2007) of the test year, I used Mr. Hutchens' growth factor of 2.5 percent per year and adjusted the mid-year customer count by 1.25 percent.

THF – C3 presents a summary of the adjustment and THF – C4 presents the details of the calculations. The Excel model used as the basis for THF – C4 is the Company annualization model with my end of period and growth adjustments replacing the Company's assumed values in the model. My calculations result in an adjustment of $869,221 as compared to the Company's adjustment of negative $302,550 (total of $516,003).

Weather Normalization

Q. Did you propose a Weather Normalization adjustment?

A. Yes. My Customer Annualization adjustment resulted in an increase in the number of customers for the test year. Since the test year was cooler than normal, these additional customers could be expected to consume more natural gas than in a normal year. Schedule THF – C5 shows that the Weather Normalization adjustment based on my Customer Annualization pro forma adjustment results in a weather normalization pro forma adjustment of -$903,890 compared to the Company's weather normalization pro forma adjustment of -$882,454. The net change that I am proposing is -$21,436.

Rate Case Revenue Annualization

Q. What is Rate Case Revenue Annualization?

A. The Rates ordered by the Commission in the Company's last rate case went into effect on December 1, 2007. The previous rates were in effect until December 1, 2007 so the new rates required annualization to reflect revenue they would have generated had they been in effect for the entire test year.

Q. Did the Company propose a pro forma adjustment representing Rate Case Revenue Annualization?

A. Yes. The Company proposed increasing annualized revenue by $1,448,476.

Q. Did you propose a pro forma adjustment representing Rate Case Revenue Annualization?

A. Yes. My Customer Annualization adjustment increased the number of test year customers; therefore, more customers would have paid the lower rates in effect prior to December 1, 2007. My proforma adjustment is presented in Schedule THF – C6 and increases the proposed Company increase in revenue for this adjustment by $349,038.

Bad Debt Expense

Q. Did you make an adjustment to the Company's proposed bad debt expense?

A. Yes. Schedule THF – C7 presents the calculations for my bad debt adjustment of negative $186,627.

Q. How is bad debt expense treated?

A. Bad debt is handled in a two part process. Actual losses are reviewed and an estimate of the expected loss is calculated. An accrual for that expected loss is booked. The actual losses are booked to those accruals.

Q. What has the Company's bad debt expense been over the last few years?

A. The actual bad debt expense experienced by the Company is as follows: 2006 - $972,007, 2007 - $668,482, 2008 - $849,695, and test year - $625,168.[2]

[2] Company response to Staff data request THF 8.12.

Q. What was the Company's Allowance for Doubtful Accounts for the years 2006, 2007, and test year end June 30, 2008?

A. Company Schedule E-1, line 13 shows that Allowance for Doubtful Accounts increased from $(366,736) in 2006, to $(1,010,624) in 2007, to $(1,219,587) at test year end June 30, 2008. This is an increase of 322.55 percent over that period.

Q. What do you determine from this increase in Allowance for Doubtful Accounts over that time period?

A. The Company is over accruing its Allowance for Doubtful Accounts.

Q. What is your recommendation?

A. I recommend that the Company's Uncollectibles rate be reduced from its 0.487 percent to 0.3468 percent until the accrual of bad debts becomes aligned with the Company's bad debt experience. At this Uncollectibles rate, the Company can expect to reduce its Allowance for Doubtful Accounts to the current Uncollectibles per Company amount of $688,379 in three years. That would provide the Company a 100 percent safety balance and it could then increase its Uncollectibles rate to its actual experience.

Fleet Fuel Expense

Q. Please explain your Fleet Fuel Expense Adjustment.

A. The Fleet Fuel Expense Adjustment is presented in Schedule THF – C8. The Company experienced average price per gallon for fuel of $3.35 during its test year, with total miles of 2,960,186 and total gallons of 222,973. The Energy Information Administration projects average fuel cost to be $1.96 for 2009. In light of the significant decline in fuel cost, I am proposing a fleet fuel expense reduction of $294,599.

Postage Expense Adjustment

Q. Please explain your Postage Expense Adjustment.

A. The Post Office announced a two cent increase in first class postage rates after the Company had filed its application. This increase is known and measurable and should be included as a test year expense. Schedule THF – C9 shows the calculation of the increase in test year postage expenses of $49,594. The Schedule shows the increase in postage for the test year customers counted by the Company plus the additional postage for the additional test year customers that resulted from my Customer Annualization pro forma adjustment.

Membership and Industry Association Dues

Q. Please explain your Membership and Industry Association Dues adjustment.

A. In its last rate case the Commission in Decision No. 70011 disallowed 3.511 percent ($1,523) associated with marketing and lobbying activities (pages 32-33). The Company agreed to this disallowance. I am proposing the same pro forma adjustment of 3.511 percent. This is shown in Schedule THF – C10.

Q. Does the Company describe an array of valuable services provided to the Company via its membership in American Gas Association ("AGA")?

A. Yes. Company Witness Smith describes many benefits he ascribes to AGA membership.

Q. Should these benefits outweigh the relatively small marketing and lobbying activities cost?

A. No. The Company has not demonstrated that AGA membership is necessary for the provision of service to its customers.

Legal Expense Adjustment

Q. Are you proposing a pro forma adjustment to legal expenses?

A. Yes. The Company made a pro forma adjustment of $305,984 and my pro forma adjustment removes the Company adjustment. This is shown in Schedule THF – C11.

Q. What was the basis for the Company's pro forma legal expense adjustment?

A. According to Company Witness Dukes, the test year contained $310,000 in outside legal costs related to the last UNS Gas rate case filing that disallowed recovery and was written off within the test year. He says that once that amount is removed the Company only has $84,000 left and that is not indicative of an ongoing level of legal expenses.

Q. Do you agree that the Company's procedure was correct for removing the legal expenses associated with the last rate case?

A. No. The Company accrued legal expenses associated with its last rate case well after the date of Decision No. 70011. Therefore, this Company adjustment should be removed.

Call Center pro forma Adjustment

Q. Please explain the Call Center expense.

A. The total test year call center charge to UNS Gas was $1,399,522, which averages $116,627 per month. In the last rate case, the Company had increased its monthly call center costs from $17,636 to $76,227 and requested it be allowed to recover this amount because the consolidated call center provided a higher level of service to customers. In addition, the Company said the Call Center could handle increased call traffic (which had nearly doubled), expanded service hours, and provided one number service for gas and electric customers in Mohave and Santa Cruz counties. The Commission allowed the Company to recover the increased costs in its rates.

Since the last rate case, the average monthly cost has increased from $76,227 to $116,627 and, rather than doubling, the number of service orders per month has declined from 5,435 in 2006 to 4,646 in 2008. I present my call center pro forma adjustment in Schedule THF – C12. I am recommending that the Commission disallow the increase of $484,798 because the number of service calls has decreased and yet call center costs have increased by 53% since the last rate case. Unless the Company can show that the increased call center expense resulted in savings elsewhere, and that customers have benefited by this increase in cost, the Commission should not permit this increase.

Interest Synchronization Adjustment

Q. What is interest synchronization?

A. The test year income tax expense is affected by application of the weighted cost of debt to rate base. Since my rate base is different than the Company's the interest amount will also be different. This results in an adjustment to the amount of interest included in the tax calculation. Schedule THF – C13 shows my calculations. I have increased income tax by $54,906 to reflect this impact.

Incentive Compensation and Exec. Comp/Benefits Pro Forma Adjustment

Q. Please explain your proforma adjustments for incentive compensation and Executive Compensation/Benefits.

A. In its last rate case the Commission disallowed certain incentive compensation and Supplemental Executive Retirement expenses. For various reasons the Commission decided to disallow 50 percent of certain incentive program costs and all Supplemental Executive Retirement Plan costs. The Commission, in its Decision No. 70011 stated "Implicit in the Company's argument is the concept that 'if we don't recover fully what we believe are our reasonable costs in our preferred manner, we'll simply shift those costs

to another account to disguise the costs and ultimately ensure recovery.' " (Page 28, Lines 20 – 23)

The Company may have behaved in just the manner suggested by the Commission. The total incentive compensation and executive compensation/benefits increased by almost 15 percent between 2007 and 2008, but individual programs seem to have evolved considerably since the last rate case. I recommend that the Company share the incentive compensation expenses with the owners of the Company for PEP related incentive compensation. The PEP pro forma adjustment is shown in Schedule THF – C14 and is one half of the total PEP costs, or $117,394.

Schedule THF – C15 shows the pro forma adjustment for SERP related expenses. I am recommending that the Commission disallow $310,412 of SERP related expenses in this proceeding. The Company identified this SERP related expense amount in its lead lag study.

Payroll Tax Expense Adjustment

Q. Please explain your payroll tax expense adjustment.

A. The Payroll Tax Expense is related to the PEP incentive pay adjustment. Schedule THF – C16 show this pro forma adjustment. I estimated payroll tax expense to be 10 percent of the PEP incentive allowance. This is slightly higher than the social security and Medicare percentages but lower than total benefits.

Rate Case Expense Adjustment

Q. Please explain your Rate Case Expense pro forma Adjustment.

A. This is an adjustment provided by the Company in its response to Data Request 6.88 and is reproduced as THF – C17. It removes the test year amortization of rate case expense of $300,000 allowed in Decision No. 70011 for the 2006 rate case that will be recovered prior to new rates becoming effective. The adjustment results in a reduction of test year expense of $58,333.

Income Tax Adjustment

Q. Please explain your income tax adjustment.

A. This adjustment is shown on page 4 of Schedule THF – C2. It reflects the income tax effect of the pro forma changes in income and expense items.

COST OF SERVICE - RATE DESIGN

Q. Are you proposing a rate design for the Company to use to recover its revenue deficiency?

A. Yes.

Q. What is the underlying rationale for the structure and magnitude of the tariffs you are proposing?

A. The underlying rationale for the structure and magnitude of the tariffs that I am proposing is that they should be efficient, equitable, and result in providing the Company the opportunity to recover its cost of providing service. Rates should be simple and easy to understand, and minimize revenue fluctuations, they should be efficient in the sense that wasteful production and consumption practices are discouraged, and they should not be

discriminatory. With respect to rate levels and customer charges, while cost-based rates are an important consideration in rate design, gradualism is also important.

Q. Would you give a general overview of natural gas rates?

A. Yes. Generally, costs for natural gas service consists of two parts. First is a customer, or fixed, charge and second, is a volumetric, or usage, charge. With respect to the fixed charge, movement to cost-based rates (assuming the costs are calculated correctly), should not be so abrupt as to cause rate shock.

Q. What is the procedure you used to determine your proposed tariffs?

A. The first step is to determine the Company's revenue requirement. This task was accomplished in the previous Sections of my testimony. The revenue requirement is defined as the Company's cost, including capital cost, of providing service. This cost of service is then apportioned to various customer groups on the basis of a cost of service study and rates designed to give the Company the opportunity to recover its cost of providing service.

Q. Did you have any special considerations in mind in designing the customer charge component of rates?

A. Yes. It is important to keep in mind that the Company has incentives to move as much cost, and therefore revenue recovery, to customer classes with the relatively greatest inelasticity of demand, i.e., residential customers. Demand for residential natural gas service is seasonal and the demand may fluctuate less than demand by other customer groups. By moving as much revenue recovery as possible to fixed monthly residential customers the Company may be passing more of its financial risk on to a customer class that adds comparatively little to that risk.

It is also important to consider intra-customer class cross-subsidization. In order to address a possible volumetric subsidization issue by moving revenue recovery from a volumetric basis to a customer charge basis, it is likely that the previously subsidizing customers could become subsidized customers. The net gain, then could be zero in that another subsidization problem is created.

Q. Did the Company prepare a cost of service study in support of its application for rate relief?

A. Yes. This was presented in the G Schedules in the Company's filing and was sponsored by Company Witness Erdwurm.

Q. Did the Company conduct its cost of service study consistent with previous Commission orders regarding cost of service?

A. Yes. According to Mr. Erdwurm the study follows the traditional structure previously approved in the Company's prior rate cases.

Q. Did you review the Company's cost study?

A. Yes. I conducted a review of the cost study. Based on my review I conclude that the Cost of Service study conducted for this proceeding is consistent with the Company's previous study.

Customer Assistance Residential Energy Support ("CARES") Program

Q. What is the CARES Program?

A. The CARES program provides for a discounted Minimum Customer charge of $7.00 per month throughout the calendar year. In addition, CARES customers receive a $.015 per therm monthly discount on the first 100 therms used during the winter billing months of

November through April. To be eligible for the CARES discount, the customer must have a gas account in their name and have a combined household income at or below 150 percent of the federal poverty level.

Q. Is the Company proposing a change in its CARES residential rate?

A. No. The Company is proposing to leave the CARES residential rate at its current level. That is $7.00 monthly customer charge and $.177 per therm for the first 100 therms used in the winter heating season and $.327 per therm after the first 100 therms in the winter heating season and in the summer.

Q. Is the Company proposing a change in the CARES tariff?

A. Yes. The Company is proposing to increase its R10 residential rate but not its CARES R12 residential rate. So the Company is proposing to de-link these two residential rates.

Q. What is the Warm Spirits Program?

A. Warm Spirits is a program where customers can help their neighbors by pledging a fixed amount which is added to their monthly bill or make a random contribution by entering the contribution amount on their bill payment coupon and include their amount with their monthly payment.

Q. Is the Company proposing changes in its low-income assistance programs?

A. Yes. The Company is proposing to hold meetings of interested stakeholders to discuss modifications to the CARES program. According to Company Witness Erdwurm the Company is agreeable to changes so long as they are funded by other retail customers and are billable through the customer information and billing system. With respect to its Warm Spirits Program the Company is proposing a "round-up" program. Under this

program, customers who signed up for the program would see their bills "rounded up" to the next dollar and the difference between the actual bill amount and the rounded-up amount would be contributed to the Warm Spirits Program.

Q. Do you agree with the Company's proposals regarding expansion of its low-income assistance program?

A. Yes.

Rules and Regulations

Q. Is the Company proposing changes to its rules and regulations?

A. Yes. Mr. Smith presents the proposed changes on page 5 of his prepared testimony.

Q. What are the Company's proposed changes?

A. The Company is proposing the following changes to its Rules and Regulations:

Section 2 – Add definitions for "Elderly", "Excess Flow Valve", "Service Transfer", "Special Call Out" and "Trip Charge". Delete the definitions of "Senior Citizen" and "Working Hours". Clarify the definition of "Service Reconnection Charge";

Section 3 – Clarify the applicability of service establishment, reestablishment and reconnection charges, as well as the charges for service transfers and multiple attempts to connect;

Section 6 – Increase the charge for service line establishments from $16.00 per foot to $22.50 per foot. For those customers who perform the trenching work, the charge for service line establishments will increase from $12.00 per foot to $16.50 per foot;

Section 8 – Delete the "Table of Atmospheric Pressure Bases" by geographical zone descriptions in favor of a more simplified version that shows the atmospheric pressure bases within specific elevation ranges; and

Section 17 – Add the Statement of Additional Charges to the end of the Rules and Regulations.

Q. Do you agree with the Company's proposed changes to its Rules and Regulations?

A. Yes. The Company's explanation for its proposed changes to Sections 2, 3, and 8 appear to be reasonable. It's proposed modifications to charge for service line establishments, Section 6, appears to be based on the incremental cost of service line establishment. Section 17 is proposed by the Company so that the Statement of Additional Charges can be found in one place.

Q. Do you agree with the Company's proposed changes to Section 6?

A. In general, I agree with the changes. The Company addressed the possible problem of mis-pricing hook up fees which could result in existing customers subsidizing new customers. According to the Company, its proposed fees are based on incremental cost studies and, therefore, should eliminate possible cross subsidization of existing customers by new customers. However, the Company raised a valid concern regarding the possibility of higher hook-up fees placing it in a competitive disadvantage relative to other energy providers such as propane and electricity. I have requested any studies the Company may have that address this issue and propose that the Commission assure itself that the Company will not be placed in a competitive disadvantage because of the proposed rates. This could conceivably create an unintentional problem while solving another problem.

Statement of Additional Charges

Q. What is the Statement of Additional Charges?

A. As mentioned above, the Statement of Additional Charges is a consolidation of various charges into Section 17 of the Company's Rules and Regulations.

Q. What are the charges that the Company proposes to consolidate into Section 17, the Statement of Additional Charges?

A. Company Witness Smith presents the Company's proposed service fees on page 7 of his testimony. The current and proposed fees are:

	Current	Proposed
Trip Fee		
Service Transfer:	$15.00	$20.00
Collection Fee	$20.00	$20.00
Customer Requested Meter Re-Reads	$15.00	$20.00
Multiple Attempts to Connect	$15.00	$20.00
Service Establishment & Reestablishment		
During Working Hours	$25.00	$35.00
Reestablishment of Service Due to Non-Pymt		
During Working Hours	$45.00	$35.00
Service Establishment & Reestablishment		
Outside Normal Working Hours	$35.00	$50.00
Reestablishment of Service Due to Non-Pymt		
Outside Working Hours	$55.00	$50.00
Customer Requested Meter Test	$65.00	$90.00
Insufficient Funds	$15.00	$10.00
Interest on Customer Deposits	1-yr Treasury rate	

Q. Do you agree with the Company's proposed changes in its Statement of Additional Charges?

A. Yes. The Company has conducted incremental cost studies ("ICS") for most of these charges and the proposed rates are in line with the results of the ICS. The Company does not provide an ICS for insufficient funds charges, but is proposing to reduce that charge.

Changes to T-1 and T-2 Pricing Plans

Q. Does the Company propose changes to its T-1 and T-2 pricing plans?

A. Yes.

Q. What do the T-1 and T-2 pricing plans apply to?

A. They apply to certain large customers.

Q. What are the changes proposed by the Company for these plans?

A. The Company is proposing that the monthly operating window under which the Customer's cumulative imbalances must be within plus or minus 5 percent of the month's total of daily scheduled transportation quantities, plus any Company-approved imbalance adjustment quantity, or 10,000 therms, whichever is greater be changed to 1,500 therms.

Q. Do you agree with this proposed change?

A. Yes. Currently the Company's monthly imbalance cash out threshold under its El Paso Natural Gas tariff is only 20,000 therms. Permitting each transportation customer to affect up to one half its permitted limit places the Company at an unnecessary risk level.

Changes to Residential R10 Customer Charges

Q. What rate design changes does the Company propose for residential R10 customers?

A. The Company is proposing a phase-in over three years of an increase in customer charges with a corresponding reduction in distribution margin. These proposed rates are:

Year 1:	Customer charge:	$10.00
	Distribution Margin:	$0.3920
Year 2:	Customer charge:	$12.00
	Distribution Margin:	$0.3479
Year 3:	Customer charge:	$14.00
	Distribution Margin:	$0.3039

Q. What is the Company's justification for this proposal?

A. According to the Company, it is not recovering enough of its customer related costs in its customer charge. The Company asserts that its revenues are seasonal and that a volumetric-heavy rate structure contributes to its revenue instability. It claims that if it were permitted to increase its customer charge then its revenue instability would be reduced.

Q. Does the Company offer any other reasons in support of its proposed residential customer charge multi-year phase in?

A. Yes. The Company states that because of the nature of its service territory under its current rate structure customers in cooler areas have higher usage than customers in warmer areas and, as a result, subsidize customers in warmer areas. The Company suggests that adoption of its proposal would eliminate this subsidization.

Q. Do you agree with the Company's proposed multi-year phase in of increased customer charges?

A. No. The Company's proposal violates a basic rule of rate design, that is, that rates should be simple and easy to understand. The Company's proposal provides its R10 residential customers with a confusing and moving target. I recommend that the Commission not approve this type of rate design change because of the adverse impact on customers.

Q. Do you agree that the Company's proposed residential rate implementation plan would eliminate intra-customer class subsidies?

A. If it eliminated the subsidy identified by the Company, then it might create another subsidy. That would be a possible subsidization of its northern customers by its southern customers as a result of the increase in customer charge to southern customers relative to total cost of service. In my opinion, the fact that some customers in a customer class may use more or less natural gas than other customers does not form the basis for a radical change in rates and rate structure. The concept of gradualism is important and the Company appears to have been successful in increasing the customer charge, although not by as much or as rapidly as it might have wished.

Customer Class Risk.

Q. Dr. Fish, did you conduct a study to identify the risk associated with the Company's various customer classes?

A. Yes.

Q. What is a customer class risk study?

A. A customer class risk study is a study that identifies and quantifies the risk associated with customer classes. The Company claims that it requires a significant increase in R10

customer charges in order to align its customer charge with customer-related costs, because of possible subsidization of southern residential customers by northern residential customers, and because of the extreme fluctuations in revenue over the course of a year.

Q. What is customer class risk?

A. Unanticipated changes in consumption represent risk. The Company's sales can be expected to vary over time to some extent due to long-term growth and to seasonal and cyclical variation. To the extent that these changes in sales are regular, recurring, and predictable they do not represent risk. Unanticipated changes in consumption can be identified with the use of time series analysis and a measure of risk is the Coefficient of Variation. The Coefficient of Variation is the ratio of the standard deviation of a series of observations to its arithmetic mean, i.e., CV = s.d./mean.

Q. What did your customer class risk study indicate?

A. The results of the study are presented in Schedule THF – RD1. The Company provided monthly data for residential, commercial, industrial, public authority and total Company for at least five years. I conducted a time series analysis (TSCI) on the decatherm sales for these classes and total. In order to isolate the risk component of the series I removed the trend and seasonal components, leaving the cyclical and irregular components. The cyclical and irregular components represent risk and the Column headed Time Series, TSCI, TSCI/TS shows the coefficient of variation for each of the classes and total. As one would expect residential, commercial and public authority customer classes had a much lower coefficient of variation than did the industrial customer class. This is confirmed by the experience of the Company with an industrial customer that used a large quantity of natural gas during the test year then experienced a significant reduction in usage after the test year ended. The second column headed Raw Data, shows the coefficient of variation

for the same classes using only the raw data. Again, as one would expect, the results are not so clear because known and measurable changes are not removed from the series.

Q. What do the results of your study indicate?

A. They suggest that while the Company is experiencing fluctuations in revenue over the course of a year, those fluctuations, outside of the industrial customer class, do not reflect a high level of risk. Since the proportion of industrial sales to total system sales is quite small, the negative impact of the industrial class on the Company is low. However, the Company does experience revenue fluctuations and although the fluctuations are highly predictable, should continue to take action to minimize possible adverse effects of these fluctuations.

Rate Design

Q. Did you identify the Company's revenue shortfall?

A. Yes. I determined that the Company had an Operating Income Deficiency of $2,077,601 and a Gross Revenue Requirement of $3,395,423.

Q. Did you prepare Schedules showing your proposed rate design?

A. Yes. I prepared Schedules THF – RD2 through THF – RD6 to present my rate design. Schedule THF – RD2 provides a summary of revenues by customer class adjusted present rates and proposed rates and Schedule THF – RD3 provides a summary of revenues by rate schedules adjusted present rates and proposed rates. Schedule THF – RD4 is a summary schedule showing current rates, proposed rates and change by class of service. Schedule THF – RD5 shows proof of revenues and Schedule THF – RD6 provides a typical bill comparison by major customer class.

Q. On Schedule THF - RD2 what is your proposed revenue increase for industrial customers I-30 and I-32?

A. The revenue increase in Schedule THF - RD2 is 49.74 percent.

Q. Is that the rate increase you are proposing for industrial customers I-30 and I-32?

A. No. On Schedule THF – RD5 I am proposing the following rate increase for industrial customers:

	Customer Charge	Distribution Margin
Small Industrial I-30	14.8%	8.5%
Large Industrial I-32	5%	21%

The aggregate proposed rate increase, shown in THF-RD6 is approximately 9 percent for both customer classes. The higher revenue increase results from the removal of an industrial customer's revenue from test year operations.

Q. Will your proposed rate increase for I-30 and I-32 customers prevent the Company from having the opportunity to recover its cost of providing service?

A. No. My proposed revenue increase for I-30 and I-32 customers is approximately 9.2 percent higher than the Company's current proposed revenue for those customer classes.

Q. Does that conclude your testimony?

A. Yes.

Schedules
Accompanying the Direct Testimony of Thomas H. Fish, Ph.D.

Schedule	Description
THF-1	Attachment 1 – Resume of Thomas H. Fish, Ph.D.
THF-2	Attachment 2 – Revenue Requirement/Rate Design Schedules
	Revenue Requirement
THF – A1	Revenue Deficiency
THF – A2	Revenue Conversion Factor
	Rate Base
THF – B1	Adjusted Rate Base
THF – B2	Summary of Adjustments to Rate Base
THF – B3	Adjusted Test Year RCND Rate Base
THF – B4	Comparative RCND Studies
THF – B5	Post Test Year Non Revenue Producing PIS
THF – B6	Customer Advances
THF – B7	Working Capital
THF – B8	Purchased Gas Lag
THF – B9	ADIT
THF – B10	Lead Lag
	Operating Income Adjustments
THF – C1	Adjusted Net Operating Income
THF – C2	Income Statement Adjustments Summary
THF – C3	Customer Annualization Summary
THF – C4	Customer Annualization Calculations
THF – C5	Weather Normalization
THF – C6	Rate Case Revenue
THF – C7	Bad Debt Expense
THF – C8	Fleet Fuel Expense
THF – C9	Postage Expense
THF – C10	AGA Expense
THF – C11	Legal Expenses
THF – C12	Call Center Expense
THF - C.13	Interest Synchronization
THF - C.14	Incentive Expense PEP
THF - C.15	Incentive Expense SERP
THF - C.16	Payroll Tax
THF - C.17	Rate Case Expense
	COS/Rate Design
THF – RD1	Customer Class Risk
THF – RD2	Summary of Revenues by Customer Class
THF – RD3	Summary of Revenues by Rate Schedule
THF – RD4	Summary of Staff Recommended Rate Design
THF – RD5	Proof of Revenue
THF – RD6	Bill Comparison

Attachment THF - 1

Curriculum Vita

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EDUCATION

University of Arkansas Ph.D., 1972, Major: Economics. Minors: Marketing/Management, Finance, and Quantitative Methods.

Central Missouri State University, 1970, Warrensburg: MA, Economics

University of Missouri - Kansas City, 1969, Kansas City BA, Economics

EXPERIENCE

Administrative proceedings – participated in over 80 proceedings involving economics, statistics, accounting, finance, market structure and industrial organization issues in telecommunications, electric, and oil and natural gas distribution industries.

Managerial experience – Over 20 years experience in managing private businesses. Experience in personnel, economics, market research, finance, accounting, and operations management. Managed technical departments in several firms and was group manager in many major projects.

Judicial proceedings – participated in over 70 proceedings involving antitrust, contract damages, insurance defense, economic loss, market structure and performance, and other related economics/statistics/finance issues.

Other engagements – participated in over 75 private industry and governmental engagements involving economics, market structure, statistics, finance, and operational issues.

Teaching Experience –Through July, 2003 Professor of Business and Economics at William Jewell College. Duties included teaching classes in Economics, Finance, Quantitative Methods, and Management.

Taught classes at Webster University, Avila College, and Longview Metropolitan College on an adjunct basis between 1984 and 1997. Taught graduate and undergraduate classes

in the areas of Management, Marketing, Financial Accounting, Finance, Statistics, Quantitative Methods, and Economics.

Experience

1981-1986 Regulatory Consulting and Expert Witness Services. Ariadair Economics Group. Concentration on Regulatory Consulting and Expert Witness Services for Regulatory Commissions and Consumer Advocates.

1986-1987 Directory, Economics Department, LMSL Consultants, Overland Park, Kansas. Concentration on Regulatory Consulting and Expert Witness Services for Regulatory Commissions and Consumer Advocates.

1987-Present Judicial and Administrative litigation consultant and expert witness, Ariadair Economics Group. Regulatory consulting and the regulatory experience led to a large number of utility antitrust and related litigation engagements in addition to regulatory Commission and Consumer Advocate regulatory engagements. During the period 1981 -2000 taught on an adjunct basis at local colleges including Avila University and Webster University. During the period 1981-1999 had Consumer Advocate clients in Arizona, Nevada, Illinois, Ohio, Pennsylvania and Maine. Also during this period had Commission clients in Nebraska, Oklahoma, Tennessee, Pennsylvania, Missouri, and South Dakota,

2001-2006 Full Professor of Business and Economics at William Jewell College, Liberty, Mo. During this period also had several judicial litigation engagements involving asset valuation and economic loss..

PUBLICATIONS

"An Analysis of Valuation of Community Bank Stocks." Quarterly Community Bank Journal, April, 1983.

"An Analysis of Trends in Prices of Community Bank Control Sales." Quarterly Community Bank Journal, July, 1983.

"An Analysis of Publicly Traded Multi-Bank Holding Company Market Performance After Acquisition of Community Banks." Quarterly Community Bank Journal, October, 1983.

"Derivation of a Valuation Index for Community Bank Control Sales." Quarterly Community Bank Journal, January, 1984.

RESEARCH

Professional Presentation

"An Econometric Model of Missouri." Presented at the Missouri Valley Economic Association, 1974.

Consulting Research

Economic Impact of Various Utility Rate Structures on State and Regional Economies.

Demographic Analysis of Economic Regions.

Determination of Market Characteristics and Parameters for Jet Aircraft Manufacturing Firms.

Determination of Optimal Refinancing and Capital Structuring and Corresponding Cost of Capital and Return for Acquisitions and Mergers.

An Econometric Analysis of NECPA Pricing Policies.

An Econometric Analysis of the Effect of the Proposed 15% Severance Tax (Senate Bill #892) on the Economy of the State of Kansas.

Curtailment of Demand Econometric Model for Cincinnati Bell Telephone Company's Service Area.

Development of Control Procedures for Large Construction Projects.

Development of Automatic Bill of Materials Systems of Manufacturing Processes.

Development of Planning and Forecasting Models.

Utilization of Economic Analysis in Business Decision-Making Situations (Seminar).

A Long-Term Forecast of Relative Costs of Alternative Energy Sources.

Analysis of the Validity of Sampling Procedures for Determination of the Growth Component of the DCF Model.

Analysis of the Relative Risk of Customer Classes of Electric Companies.

Development of EDP Models for Determining Optimal Price, Financing Strategy, and Expected Return for Corporate Acquisitions and Mergers.

Analysis of Asset Valuation in Bankruptcy Cases.

Preparation of Bank Charter Applications and Supporting Economic/Demographic Analyses.

COLLEGES COURSE TAUGHT

Management

Bank Management
Financial Management
Global Issues in Business

Human Resource Management
International Business Management
Introduction to Business
Introduction to Management
Marketing Research
Organization and Management
Organizational Behavior
Small Business Management
Strategic Management
Telecommunications Management

Finance

Financial Management
Intermediate Finance
International Finance
Portfolio Selection
Principles of Finance
Readings in Finance
Seminar in Finance I
Seminar in Finance II

Quantitative Methods

Business Math
Econometrics I
Econometrics II
Quantitative Analysis I
Quantitative Analysis II
Statistics I
Statistics II

Computer Information Systems/Information Technology

Computer Applications in Business
IT Systems Analysis and Design
Systems Analysis and Design I
Systems Analysis and Design II

Economics

Advanced Microeconomics
Business Cycles and Forecasting
Current Issues in Economics
Econometrics I
Econometrics II
Fiscal Policy
Industrial Organization

Intermediate Macroeconomics
Intermediate Microeconomics
International Economics
Macroeconomics
Managerial Economics
Microeconomics
Money and Banking
Principles of Econ I
Principles of Econ II
Readings in Economics

Financial Accounting

Cost Accounting
Federal Income Tax
Financial Accounting I
Financial Accounting II
Intermediate Financial Accounting
Managerial Accounting

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Revenue Requirement
Test Yeat Ended June 30, 2009

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) STAFF ORIGINAL COST	(C) COMPANY RCND	(D) STAFF RCND	(E) COMPANY FAIR VALUE	(F) STAFF FAIR VALUE
1	Adjusted Rate Base	$ 182,293,105	$ 178,509,369	$ 329,265,770	$ 324,538,937	$ 255,779,438	$ 251,524,153
2	Adjusted Operating Income (Loss)	$ 11,600,004	$ 13,544,256	$ 11,600,004	$ 13,544,256	$ 11,600,004	$ 13,544,256
3	Current Rate of Return (Line 2 / Line1)	6.36%	7.59%	3.52%	4.17%	4.54%	5.38%
4	Required Operating Income (Line 5 X Line 1)	$ 15,950,647	$ 14,709,172	$ 17,390,762	$ 14,727,023	$ 17,390,762	$ 14,727,023
	Plus fair value (Line 6)		$ 15,621,857		$ 15,621,857		$ 15,621,857
5	Required Rate of Return	8.75%	8.24%	8.75%	8.24%**	8.75%	8.24%**
6	Fair Value Adjustment*	0.79%	$ 912,685	-3.47%	$ 912,685	-1.95%	$ 912,685
7	Total	9.54%		5.28%		6.80%	
8	Operating Income Deficiency (Line 4 - Line 2)***	$ 5,790,758	$ 2,077,601	$ 5,790,758	$ 2,077,601	$ 5,790,758	$ 2,077,601
9	Gross Revenue Conversion Factor	1.6366	1.6343	1.6366	1.6343	1.6366	1.6343
10	Increase in Gross revenue requirement	$ 9,480,876	$ 3,395,423	$ 9,480,876	$ 3,395,423	$ 9,480,876	$ 3,395,423

References:

Columns (A), (C), and (E) Company Schedules A-1, C-1, and D-1
Column (B), Schedules THF-B-1, THF-C-1
Column (D), Schedule THF- B-1, THF - C-1
Column (F), Average of Columns (B) and (D)
Line 7, Company adopted Staff and RUCO Tax values from Docket G-04204A-06-0463
*Staff Fair Value Adjustment = (FVRB-OCRB)*risk free rate [1.25%]
**Staff Witness Parcell
***Line 4 + Line 6

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Gross Revenue Conversion Factor
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION	REFERENCE	(A) PERCENTAGE
1	Revenues		100.00%
2	Less Uncollectibles	Company Schedule C-3, Line 2	0.3468%
3	Subtotal	Line 1 - Line 2	99.6532%
4	Less State Income Tax (6.968%) and Federal Income Tax (31.63%)	Line 3 X 38.598%	38.4641%
5	Change in Net Operating Income	Line 3 - Line 4	61.1891%
6	Gross Revenue Conversion Factor	Line 1 / Line 5	1.6343

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Original Cost and RCND Adjusted Rate Base
Test Yeat Ended June 30, 2009

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) OCRB STAFF ADJUSTMENTS	(C) OCRB AS ADJUSTED BY STAFF	(D) COMPANY RCND	(E) RCND STAFF ADJUSTMENTS	(F) RCND AS ADJUSTED BY STAFF
1	Gross Utility Plant in Service	$ 318,227,624	$ (1,527,588)	$ 316,700,036	$ 561,025,858	$ (2,514,427)	$ 558,511,431
2	Less: Accumulated Depreciation	$ 87,543,544		$ 87,543,544	$ 152,278,962		$ 152,278,962
3	Net Utility Plant in Service	$ 230,684,080		$ 229,156,492	$ 408,746,896		$ 406,232,469
4	Southern Union Acquisition Premium						
5	Less: Accum Amort. So. Union Acq. Premium				$ 3,553		$ 3,553
6	Net Southern Union Acquisition Premium				$ (3,553)		$ (3,553)
7	Citizens Acquisition Discount	$ (30,709,737)		$ (30,709,737)	$ (55,128,579)		$ (55,128,579)
8	Less: Accumulated Amort. - Citizens Acq. Discount	$ (3,935,647)		$ (3,935,647)	$ (6,658,438)		$ (6,658,438)
9	Net Citizens Acquisition Discount	$ (26,774,090)		$ (26,774,090)	$ (48,470,141)		$ (48,470,141)
10	Total Net Utility Plant	$ 203,909,990		$ 202,382,402	$ 360,273,202		$ 357,758,775
11	Customer Advances for Construction	$ (11,235,876)	$ 589,152	$ (11,825,028)	$ (12,759,773)	$ 589,152	$ (13,348,925)
12	Customer Deposits	$ (2,609,271)		$ (2,609,271)	$ (2,609,271)		$ (2,609,271)
13	Accumulated Deferred Income Taxes	$ (10,606,875)	$ 38,994	$ (10,645,869)	$ (18,474,527)	$ 38,994	$ (18,513,521)
14	Total Deductions	$ (24,452,022)		$ (25,080,168)	$ (33,843,571)	$ -	$ (34,471,717)
15	Allowance for working Capital	$ 2,364,921	$ 1,628,004	$ 736,917	$ 2,364,921	$ 1,628,004	$ 736,917
16	Regulatory Assets	$ 492,590		$ 492,590	$ 492,590		$ 492,590
17	Regulatory Liabilities	$ (22,372)		$ (22,372)	$ (22,372)		$ (22,372)
18	Total Rate Base	$ 182,293,107		$ 178,509,369	$ 329,264,770		$ 324,538,937

References:
Columns (A) and (D) Company Schedule B-1

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Original Cost Rate Base Pro Forma Adjustments
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(A) COMPANY ACTUAL END OF TEST YEAR	(B) COMPANY ADJUSTMENTS	(C) COMPANY ADJUSTED END OF TEST YEAR	(D) Post TY Non-Rev Plnt in Ser	(E) Customer Advances Adjst	(F) Accum Def Income Taxes
1	Gross Utility Plant in Service	$ 340,154,214	$ (21,926,590)	$ 318,227,624	$ (1,527,588)		
			$ -				
2	Less: Accumulated Depreciation	$ 93,765,398	$ (6,221,854)	$ 87,543,544			
3	Net Utility Plant in Service	$ 246,388,816	$ (15,704,736)	$ 230,684,080	$ (1,527,588)		
4	Southern Union Acquisition Premium	$ 18,271,349	$ (18,271,349)	$ -			
5	Less: Accum Amort. So. Union Acq. Premium	$ 2,125,967	$ (2,125,967)	$ -			
6	Net Southern Union Acquisition Premium	$ 16,145,382	$ (16,145,382)	$ -			
7	Citizens Acquisition Discount	$ (68,391,292)	$ 37,681,555	$ (30,709,737)			
8	Less: Accumulated Amort. - Citizens Acq. Discount	$ (8,764,777)	$ 4,829,130	$ (3,935,647)			
9	Net Citizens Acquisition Discount	$ (59,626,515)	$ 32,852,425	$ (26,774,090)			
10	Total Net Utility Plant	$ 202,907,683	$ 1,002,307	$ 203,909,990	$ (1,527,588)		
11	Customer Advances for Construction	$ (11,825,028)	$ 589,152	$ (11,235,876)		$ (589,152)	
12	Customer Deposits	$ (2,609,271)	$ -	$ (2,609,271)			
13	Accumulated Deferred Income Taxes	$ (15,056,983)	$ 4,450,108	$ (10,606,875)			$ (38,994)
14	Total Deductions	$ (29,491,282)	$ 5,039,260	$ (24,452,022)			
15	Allowance for working Capital	$ 2,266,954	$ 97,967	$ 2,364,921			
16	Regulatory Assets	$ 492,590	$ -	$ 492,590			
17	Regulatory Liabilities	$ (22,372)	$ -	$ (22,372)			
18	Total Rate Base	$ 176,153,573	$ 6,139,534	$ 182,293,107	$ (1,527,588)	$ (589,152)	$ (38,994)

References:
Columns (A) and (C) Company Schedule B-2

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Original Cost Rate Base Pro Forma Adjustments
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(G) Working Capital	(H) STAFF ADJUSTMENTS	(I) AS ADJUSTED BY STAFF
1	Gross Utility Plant in Service		$ (1,527,588)	$ 316,700,036
				$ -
2	Less: Accumulated Depreciation			$ 87,543,544
3	Net Utility Plant in Service		$ (1,527,588)	$ 229,156,492
4	Southern Union Acquisition Premium			$ -
5	Less: Accum Amort. So. Union Acq. Premium			$ -
6	Net Southern Union Acquisition Premium			$ -
7	Citizens Acquisition Discount			$ (30,709,737)
8	Less: Accumulated Amort. - Citizens Acq. Discount			$ (3,935,647)
9	Net Citizens Acquisition Discount			$ (26,774,090)
10	Total Net Utility Plant		$ (1,527,588)	$ 202,382,402
11	Customer Advances for Construction		$ (589,152)	$ (11,825,028)
12	Customer Deposits			$ (2,609,271)
13	Accumulated Deferred Income Taxes		$ (38,994)	$ (10,645,869)
14	*Total Deductions*			$ (25,080,168)
15	Allowance for working Capital	$ (1,628,004)	$ (1,628,004)	$ 736,917
16	Regulatory Assets		$ -	$ 492,590
17	Regulatory Liabilities		$ -	$ (22,372)
18	Total Rate Base	$ (1,628,004)	$ (3,783,738)	$ 178,509,369

References:
Columns (A) and (C) Company Schedule B-2

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Adjusted Test Year RCND Rate Base
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(A) 06-0463 COMMISSION ORIGINAL COST RATE BASE	(B) 06-0463 COMMISSION RCND RATE BASE	(C) 08-0571 COMPANY ORIGINAL COST RATE BASE	(D) 08-0571 COMPANY RCND RATE BASE	(E) % COLUMN B OF COLUMN A	(F) % COLUMN D OF COLUMN C
1	Gross Utility Plant in Service	$ 271,980,463	$ 367,054,190	$ 318,227,624	$ 561,025,858	134.956%	176.297%
2	Less: Accumulated Depreciation	$ 72,006,708	$ 97,114,865	$ 87,543,544	$ 152,278,962	134.869%	173.947%
3	Net Utility Plant in Service	$ 199,973,755	$ 269,939,325	$ 230,684,080	$ 408,746,896	134.987%	177.189%
4	Southern Union Acquisition Premium						
5	Less: Accum Amort. So. Union Acq. Premium	$ -	$ -		$ 3,553		
6	Net Southern Union Acquisition Premium	$ -	$ -		$ (3,553)		
7	Citizens Acquisition Discount	$ (30,709,738)	$ (41,822,562)	$ (30,709,737)	$ (55,128,579)	136.187%	179.515%
8	Less: Accumulated Amort. - Citizens Acq. Discount	$ (1,876,981)	$ (2,560,308)	$ (3,935,647)	$ (6,658,438)	136.406%	169.183%
9	Net Citizens Acquisition Discount	$ (28,832,757)	$ (39,262,254)	$ (26,774,090)	$ (48,470,141)	136.172%	181.034%
10	Total Net Utility Plant	$ 171,140,998	$ 230,677,071	$ 203,909,990	$ 360,273,202	134.788%	176.682%
11	Customer Advances for Construction	$ (7,283,595)	$ (7,786,962)	$ (11,235,876)	$ (12,759,773)	106.911%	113.563%
12	Customer Deposits	$ (3,040,484)	$ (3,040,484)	$ (2,609,271)	$ (2,609,271)	100.000%	100.000%
13	Accumulated Deferred Income Taxes	$ (6,289,473)	$ (6,289,473)	$ (10,606,875)	$ (18,474,527)	100.000%	174.175%
14	Total Deductions	$ (16,613,552)	$ (17,116,919)	$ (24,452,022)	$ (33,843,571)	103.030%	138.408%
15	Allowance for working Capital	$ (211,136)	$ (211,136)	$ 2,364,921	$ 2,364,921	100.000%	100.000%
16	Regulatory Assets	$ 307,819	$ 307,819	$ 492,590	$ 492,590	100.000%	100.000%
17	Regulatory Liabilities	$ (19,721)	$ (19,721)	$ (22,372)	$ (22,372)	100.000%	100.000%
18	Total Rate Base	$ 154,604,408	$ 213,637,114	$ 182,293,107	$ 329,264,770	138.183%	180.624%

References:
Columns (A) and (B) Company Schedule B-1 from Docket 06-0463
Columns (C) and (D) Company Schedule B-1 from Docket 08-0571
Column (E) Column B/Column A
Column (F) Column D/Column C
Column (G) Column C/Column A
Column (H) Column D/Column B
Column (I) Column B Times Column G

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Adjusted Test Year RCND Rate Base
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(G) % COLUMN C OF COLUMN A	(H) % COLUMN D OF COLUMN B	(I) COLUMN B TIMES COLUMN G
1	Gross Utility Plant in Service	117.004%	152.846%	$ 429,467,549
2	Less: Accumulated Depreciation	121.577%	156.803%	$ 118,069,270
3	Net Utility Plant in Service	115.357%	151.422%	$ 311,394,387
4	Southern Union Acquisition Premium			
5	Less: Accum Amort. So. Union Acq. Premium			
6	Net Southern Union Acquisition Premium			
7	Citizens Acquisition Discount	100.000%	131.815%	$ (41,822,561)
8	Less: Accumulated Amort. - Citizens Acq. Discount	209.680%	260.064%	$ (5,368,445)
9	Net Citizens Acquisition Discount	92.860%	123.452%	$ (36,458,918)
10	Total Net Utility Plant	119.147%	156.181%	$ 274,845,652
11	Customer Advances for Construction	154.263%	163.861%	$ (12,012,384)
12	Customer Deposits	85.818%	85.818%	$ (2,609,271)
13	Accumulated Deferred Income Taxes	168.645%	293.737%	$ (10,606,875)
14	Total Deductions	147.181%	197.720%	$ (25,192,883)
15	Allowance for working Capital	-1120.094%	-1120.094%	$ 364,921
16	Regulatory Assets	160.026%	160.026%	$ 492,590
17	Regulatory Liabilities	113.443%	113.443%	$ (22,372)
18	Total Rate Base	117.909%	154.123%	$ 251,898,208

References:
Columns (A) and (B) Company Schedule B-1 from Dock
Columns (C) and (D) Company Schedule B-1 from Dock
Column (E) Column B/Column A
Column (F) Column D/Column C
Column (G) Column C/Column A
Column (H) Column D/Column B
Column (I) Column B Times Column G

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Comparative RCND Studies
Test Yeat Ended June 30, 2008

LINE NO.	YEAR	A HW INDEX FERC 276 STEEL MAINS '05 RCN	B BASE 435 TREND VALUE FERC 277 STEEL MAINS '05 RCN BASE 435	C TREND VALUE FERC 278 STEEL MAINS '05 RCN BASE 556	D ACTUAL TREND TO RCN STY TREND	E HW INDEX FERC 278 STEEL MAINS '08 RCN	F TREND VALUE FERC 279 STEEL MAINS '08 RCN	G CORRECT 08 TRND TP '05 TREND
1	1998	308	141.234%	180.519%	127.816%	308	183.442%	101.619%
2	1999	336	129.464%	165.476%	127.816%	336	168.155%	101.619%
3	2000	354	122.881%	157.062%	127.816%	354	159.605%	101.619%
4	2001	360	120.833%	154.444%	127.816%	360	156.944%	101.619%
5	2002	367	118.529%	151.499%	127.816%	367	153.951%	101.619%
6	2003	372	116.935%	149.462%	127.816%	372	151.882%	101.619%
7	2004	435	100.000%	127.816%	127.816%	435	129.885%	101.619%
8	2005	435	100.000%	100.000%	100.000%	556	101.619%	101.619%
9	2006					599	94.324%	
10	2007					560	100.893%	
11	2008					565	100.000%	

References:

A: From TY '05 Company RCN Study
B: 435 divided by column A value
C: 556 divided by column A value
D: Column C divided by Column B
E: From TY 06/30/08 RCN Study
F: 565 divided by Column E
G: Column F divided by Column D

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Post Test Year Non-Revenue Plant
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Remove Post Test Year Non-Revenue Plant	$	(1,527,588)	A & B

Reference
A: UNS Gas Filing, Schedule B-2
B: Testimony of Staff Witness Thomas Fish, PhD

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Customer Advances Adjustment
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Remove Post Test Year Customer Advances Adjustment	$	(589,152)	A & B

Reference

A: UNS Gas Filing, Schedule B-2
B: Testimony of Staff Witness Thomas Fish

UNS Gas, Inc
Docket No. G-04204A-08-0571
Working Capital Adjustment
Test Year Ended June 30, 2009

line no.	Discription		net change	
1	cash working capital per UNS	1588		lead/lag
2	cash working capital per staff	-1626428		
3	net adjustment requirement	-1624840	-1624840	
4	Materials and supplies per UNS	2010788		sched. THF-B8
5	Materials and supplies per staff	2010788		
6	net adjustment required	0	0	
7	Prepayments per UNS	352564		sched. THF-B8
8	Prepayments per staff	352564		
9	net adjustment required	0	0	
10	Total Working Capital Adjustment		-1624840	

UNS Gas
Docket No. G-04024A-08-0571
Purchased Gas Lag
Test Year Ending June 30, 2009

Service Month	Service Period Begin	Service Period End	Amount Paid	Payment Date	Lag Days (a)		Dollar Days
BP Energy Company							
July -	7/1/2007	7/31/2007	2,892,390	8/20/2007	35.00		101,233,667
August -	8/1/2007	8/31/2007	2,811,862	9/20/2007	35.00		98,415,166
September -	9/1/2007	9/30/2007	2,693,603	10/22/2007	36.50		98,316,498
October -	10/1/2007	10/31/2007	5,507,132	11/20/2007	35.00		192,749,607
November -	11/1/2007	11/30/2007	7,297,535	12/20/2007	34.50		251,764,943
December -	12/1/2007	12/31/2007	16,000,000	1/7/2008	35.00	b	560,000,000
December -	1/1/2008	1/15/2008	10,000,000	1/22/2008	35.00	b	350,000,000
January -	1/16/2008	1/31/2008	9,000,000	2/5/2008	35.00	b	315,000,000
January -	2/1/2008	2/15/2008	9,000,000	2/20/2008	35.00	b	315,000,000
February -	2/16/2008	2/29/2008	9,373,701	3/19/2008	35.00	b	328,079,540
March -	3/1/2008	3/31/2008	12,389,177	4/22/2008	37.00		458,399,562
April -	4/1/2008	4/30/2008	7,801,472	5/22/2008	36.50		284,753,743
May -	5/1/2008	5/31/2008	7,264,481	6/20/2008	35.00		254,256,849
June -	6/1/2008	6/30/2008	7,826,991	7/21/2008	35.50		277,858,167
			109,858,344				3,885,827,742
El Paso Natural Gas Co							
July -	7/1/2007	7/31/2007	379,421	8/24/2007	39.00		14,797,438
August -	8/1/2007	8/31/2007	377,627	9/25/2007	40.00		15,105,098
September -	9/1/2007	9/30/2007	388,581	10/25/2007	39.50		15,348,942
October -	10/1/2007	10/31/2007	438,071	11/25/2007	40.00		17,522,849
November -	11/1/2007	11/30/2007	976,464	12/21/2007	35.50		34,664,462
December -	12/1/2007	12/31/2007	1,273,618	1/25/2008	40.00		50,944,716
January -	1/1/2008	1/31/2008	1,267,429	2/25/2008	40.00		50,697,160
February -	2/1/2008	2/28/2008	1,239,857	3/24/2008	39.50		48,974,366
March -	3/1/2008	3/31/2008	1,190,404	4/22/2008	37.00		44,044,947
April -	4/1/2008	4/30/2008	568,207	5/27/2008	41.50		23,580,588
May -	5/1/2008	5/31/2008	338,302	6/23/2008	38.00		12,855,459
June -	6/1/2008	6/30/2008	352,906	7/25/2008	39.50		13,939,806
			8,790,888				342,475,831
Transwestern Pipeline Co							
July -	7/1/2007	7/31/2007	104,768	8/13/2007	28.00		2,933,518
August -	8/1/2007	8/31/2007	104,727	9/14/2007	29.00		3,037,089
September -	9/1/2007	9/30/2007	101,557	10/12/2007	26.50		2,691,256
October -	10/1/2007	10/31/2007	260,164	11/9/2007	24.00		6,243,936
November -	11/1/2007	11/30/2007	252,179	12/13/2007	27.50		6,934,912
December -	12/1/2007	12/31/2007	263,779	1/14/2008	29.00		7,649,581
January -	1/1/2008	1/31/2008	264,531	2/11/2008	26.00		6,877,800
February -	2/1/2008	2/28/2008	246,162	3/13/2008	28.50		7,015,611
March -	3/1/2008	3/31/2008	302,830	4/11/2008	26.00		7,873,585
April -	4/1/2008	4/30/2008	331,575	5/12/2008	26.50		8,786,729
May -	5/1/2008	5/31/2008	241,646	6/12/2008	27.00		6,524,454
June -	6/1/2008	6/30/2008	182,318	7/11/2008	25.50		4,649,105
			2,656,236				71,217,578
			121,305,468				4,299,521,150
Average Lag Days				35.44			

(a) Measured from midpoint of service month to payment date.

(b) unusual payment terms

December -	12/1/2007	12/31/2007	16,000,000	1/7/2008	22.00	a	352,000,000
December -	1/1/2008	1/15/2008	10,000,000	1/22/2008	14.00	a	140,000,000
January -	1/16/2008	1/31/2008	9,000,000	2/5/2008	12.50	a	112,500,000
January -	2/1/2008	2/15/2008	9,000,000	2/20/2008	12.00	a	108,000,000
February -	2/16/2008	2/29/2008	9,373,701	3/19/2008	25.50	a	239,029,379
			53,373,701				951,529,379

Average days for Dec. Jan. & Feb. for BP 17.83
Source: Company Lead-Lag study work papers

UNS Gas. Inc
Docket No. G-04204A-08-0571
ADIT Adjustment
Test Year Ended June 30, 2009

Income Taxes:		Deferred		staff adjustments	
Permanent Differences:					
Meals & Entertainment		$ -			
Normalized Timing Differences:					
263A Costs	**A1.1A**	$ (360,013)			
CARES Reg Asset	**C1A**	$ 164,197			
Depr/Amort. - Book	**1.2B**	$ 7,731,569			
Depr/Amort. - Tax	**1.2C**	$ (14,574,215)			
Dividend Equivalents	**H1A**	$ 23,687			
Pension	**I1A**	$ 3,793			
Repairs Capitalized	**J1A**	$ (816,406)			
Restricted Stock	**K1A**	$ 19,372			
Restricted Stock - Directors	**L1B**	$ 73,816			
SERP	**M1A**	$ 101,021		$	(101,021)
Stock Options	**L1A**	$ 149,525			
Vacation Accrual	**N1A**	$ 49,544			
Total Normalized Timing Differences		$ (7,434,110)	#	$	(101,021)
Total Schedule M Items		$ (7,434,110)	#	$	(101,021)
Tax Credits:					
Arizona Enterprise Zone Credit (3 yr. avg.)		-			
Tax Rate		38.6%			38.6%
Deferred Tax Expense		**2,869,418**			**38,994**

M Items

UNS Gas Inc
Docket No. G-04204A-08-0571
Lead-Lag Study
Test Year Ended June 30, 2008

Description	FERC	Pro Forma Test Year Amount	adjustment	adjusted amount	Ref (1)	Revenue Lag Days	Expense Lag Days	Net Lag Days	Lead/Lag Factor	Cash Working Capital Required
(A)		(B)	(C)	(D)		(E)	(F)	Col. C - Col. I (G)	(Col. E/365) (F)	(Col. F X Col.B) (G)
Operating Expenses:										
Non-Cash Expenses -										
Bad Debts Expense	904	$ 688,379	$ 185,933	502,446	THF--C7					$ -
Depreciation	403/404	9,057,437		9,057,437						-
Amortization	Multi	(817,432)		(817,432)						-
Deferred Income Taxes	410/411	2,869,418	38,994	2,830,424	THF--B9					-
Other Operating Expenses -										
Salaries and Wages	Multi	7,750,405	10,905	7,739,500	THF--C16	40.70	24.50	16.20	0.0444	343,634
Incentive Pay	Multi	310,278	310,278	-	THF--C15	40.70	267.00	(226.30)	(0.6200)	-
Purchased Gas	555	87,528,793		87,528,793	THF--B8	40.70	35.44	5.26	0.0144	1,260,415
Office Supplies and Expenses	921	1,057,383	(49,594)	1,106,977	THF--C9	40.70	20.72	19.98	0.0547	60,552
Injuries and Damages	925	508,477		508,477		40.70	64.75	(24.05)	(0.0659)	(33,509)
Pensions and Benefits	926	1,544,121		1,544,121		40.70	54.66	(13.96)	(0.0382)	(58,985)
Support Services - TEP (Direct	Note A.	7,079,483	968,123	6,111,360	"A"	40.70	44.75	(4.05)	(0.0111)	(67,836)
Property Taxes	408	3,610,079		3,610,079		40.70	213.00	(172.30)	(0.4721)	(1,704,318)
Payroll Taxes	408	560,124	834	559,290	THF--C16	40.70	19.41	21.29	0.0583	32,607
Current Income Taxes	409	734,254	1,267,490	(533,236)	THF--C2	40.70	41.42	(0.72)	(0.0020)	1,066
Interest on Customer Deposits	431	137,200		137,200		40.70	182.50	(141.80)	(0.3885)	(53,302)
Other Operations and Mainten	Multi	6,212,916	294,599	5,918,317	THF-C8	40.70	53.10	(12.40)	(0.0340)	(201,223)
Total Operating Expenses		$128,831,315	$ 3,027,562	$ 125,803,753						
Other Cash Working Capital Elements:										
Interest on Long-Term Debt	Calc	5,924,526	(54,906)	5,979,432	THF--C13	40.70	89.50	(48.80)	(0.1337)	(799,450)
Revenue Taxes and Assessme	Calc	13,847,423	(968,117)	14,815,540	"C"	40.70	50.70	(10.00)	(0.0274)	(405,946)
Total Cash Working Capital-calculated										$ (1,626,296)
Total Cash Working Capital-per UNS										1,568
Change in working capital per staff										(1,627,864)
ProForma Operating Expenses - Excluding Income		$ 37,698,831	"C"	PER THF	"A"	1,614.00	AGA	THF--C10		
Purchased Gas Lead/Lag Only		87,528,793	REVENUE	144,874,080		484,798.00	CALL CENTE	THF--C12		
ProForma Oper. Exp. To Tie Too - Excl Income Ta		125,227,624	RATE	0.0889		117,394.00	INCENTIVE	THF--C14		
Less: 1, 2, 3, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14		119,014,727		12,879,306		305,984.00	LEGAL EXPE	THF--C11		
Other O&M		$ 6,212,897	CUR. REVENU	(13,847,423)		58,333.00	RATE CASE E	THF--C17		
			CHANGE	(968,117)		968,123.00				

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Adjusted Net Operating Income
Test Yeat Ended June 30, 2009

LINE NO.	DESCRIPTION	(A) COMPANY UNADJUSTED	(B) COMPANY PRO FORMA ADJUSTMENTS	(C) COMPANY ADJUSTED	(D) STAFF ADJUSTMENTS	(E) STAFF ADJUSTED
	Operating Revenues					
1	Gas Retail Revenues	$ 161,759,581	$ (110,601,818)	$ 51,157,763	$ 1,499,373	$ 52,657,136
2	Other Operating Revenue	$ 1,636,425	$ 108,318	$ 1,744,743		$ 1,744,743
3	Total Operating Revenues	$ 163,396,006	$ (110,493,500)	$ 52,902,506	$ 1,499,373	$ 54,401,879
	Operating Expenses					
4	Purchased Gas	$ 109,328,534	$ (108,930,899)	$ 397,635		$ 397,635
5	Other Operations and Maint Expense	$ 24,753,535	$ (34,422)	$ 24,719,113	$ (1,655,319)	$ 23,063,794
6	Depreciation and Amortization	$ 8,437,470	$ (197,465)	$ 8,240,005		$ 8,240,005
7	Taxes Other than Income Taxes	$ 3,000,914	$ 1,341,164	$ 4,342,078	$ (11,739)	$ 4,330,339
8	Income Taxes	$ 4,428,062	$ (824,391)	$ 3,603,671	$ 1,222,179	$ 4,825,850
9	Total Operating Expenses	$ 149,948,515	$ (108,646,013)	$ 41,302,502	$ (444,879)	$ 40,857,623
10	Operating Income	$ 13,447,491	$ (1,847,487)	$ 11,600,004	$ 1,944,252	$ 13,544,256
	Other Income and Deductions					
11	Allowance for Equity Funds	$ 137,755				
12	Other - Net	$ 241,016				
13	Total Other Income and Deductions	$ 378,771				
14	Income Before Interest Expense	$ 13,826,262				
	Interest Expense					
15	Interest on Long-Term Debt	$ 6,429,478				
16	Other Interest Expense	$ 324,398				
17	Allowance for Borrowed Funds	$ (101,633)				
18	Total Interest Expense	$ 6,652,243				
19	Net Income Available for common Stock	$ 7,174,019				

References:
Columns (A) and (C) Company Schedule E-2, C-2, A-1, A-2

UNS Gas, Inc
Docket No. G-04204A-08-0571
Adjustments to Net Opereating Revenue
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(A) Incentive Expense SERP	(B) Incentive Expense PEP	(C) Customer Annualization	(D) Weather Normalization	(E) Payroll Tax Expense	(F) Rate Case Expense
	Operating Revenues						
1	Gas Retail Revenues			$ 1,171,771	$ (21,436)		
2	Other Operating Revenue						
3	Total Operating Revenues			$ 1,171,771	$ (21,436)		
	Operating Expenses						
4	Purchased Gas						
5	Other Operations and Maint Expense	$ (310,412)	$ (117,393)				$ (58,333)
6	Depreciation and Amortization						
7	Taxes Other than Income Taxes					$ (11,739)	
8	Income Taxes						
9	Total Operating Expenses	$ (310,412)	$ (117,393)			$ (11,739)	$ (58,333)
10	Operating Income	$ 310,412	$ 117,393	$ 1,171,771	$ (21,436)	$ 11,739	$ 58,333

References: Schedules THF - C3 -THF - C17

UNS Gas, Inc
Docket No. G-04204A-08-0571
Adjustments to Net Opereating Revenue
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(G) Rate Case Revenue	(H) Call Center	(I) AGA Expense	(J) Legal Expenses	(K) Fleet Fuel Expense	(L) Interest Synchronization
	Operating Revenues						
1	Gas Retail Revenues	$ 349,038					
2	Other Operating Revenue						
3	Total Operating Revenues	$ 349,038					
	Operating Expenses						
4	Purchased Gas						
5	Other Operations and Maint Expense		$ (484,798)	$ (1,673)	$ (305,984)	$ (294,599)	$ 54,906
6	Depreciation and Amortization						
7	Taxes Other than Income Taxes						
8	Income Taxes						
9	Total Operating Expenses		$ (484,798)	$ (1,673)	$ (305,984)	$ (294,599)	$ 54,906
10	Operating Income	$ 349,038	$ 484,798	$ 1,673	$ 305,984	$ 294,599	$ (54,906)

References: Schedules THF - C3 -THF - C17

UNS Gas, Inc
Docket No. G-04204A-08-0571
Adjustments to Net Opereating Revenue
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(M) Postage Expense	(N) Bad Debt Expense	(O) Income Tax	TOTAL STAFF ADJUSTMENTS
	Operating Revenues				
1	Gas Retail Revenues				$ 1,499,373
2	Other Operating Revenue				$ -
3	Total Operating Revenues				$ 1,499,373
	Operating Expenses				
4	Purchased Gas				$ -
5	Other Operations and Maint Expense	$ 49,594	$ (186,627)		$ (1,655,319)
6	Depreciation and Amortization				
7	Taxes Other than Income Taxes				$ (11,739)
8	Income Taxes			$ 1,222,179	$ 1,222,179
9	Total Operating Expenses	$ 49,594	$ (186,627)		$ (444,879)
10	Operating Income	$ (49,594)	$ 186,627	$ -	$ 1,944,252
			Tax rate:	0.38598	

References: Schedules THF - C3 -THF - C17

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Adjustment to Annualize Retail Customer Sales
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	UNS Gas Adjustment to Annualize Retail Revenue	$	(302,550)	A
2	Staff Adjustment to Annualize Retail Revenue	$	869,221	B
3	Net Staff Adjustment to Annualize Gas Retail Revenue	$	1,171,771	Line 2- Line 1

References:
A: UNS Gas Filing, Schedule C-2
B: Staff workpapers, C-2, *Schedule THF - 2.1a*

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	R10 Cust	R10 Adjustment	R10 Adjusted	R12 Cust	R12 Adjustment	R12 Adjusted
Jul-07	124,445	3,667	128,112	6,456	349	6,805
Aug-07	124,320	3,792	128,112	6,473	332	6,805
Sep-07	124,871	3,241	128,112	6,437	368	6,805
Oct-07	125,497	2,615	128,112	6,576	229	6,805
Nov-07	125,973	2,139	128,112	6,674	131	6,805
Dec-07	126,530	1,582	128,112	6,721	84	6,805
Jan-08	126,782	1,330	128,112	6,702	103	6,805
Feb-08	126,799	1,313	128,112	6,796	9	6,805
Mar-08	126,239	1,873	128,112	6,901	-96	6,805
Apr-08	125,566	2,546	128,112	7,027	-222	6,805
May-08	125,216	2,896	128,112	7,098	-293	6,805
Jun-08	124,957	3,155	128,112	7,077	-272	6,805
Totals	1,507,195	30,144	1,537,340	80,938	722	81,660

Month	R10 Delta Customer Charge	R12 Delta Customer Charge
Jul-07	$31,166	$2,443
Aug-07	$32,229	$2,324
Sep-07	$27,545	$2,576
Oct-07	$22,224	$1,603
Nov-07	$18,178	$917
Dec-07	$13,444	$588
Jan-08	$11,302	$721
Feb-08	$11,157	$63
Mar-08	$15,917	-$672
Apr-08	$21,638	-$1,554
May-08	$24,613	-$2,051
Jun-08	$26,814	-$1,904
Total Customer Charge	$256,228	$5,055
Total Delta Charges per Rate	$609,903	$7,368

$313,101	Total Customer Charge Delta		
$556,121	Total Therm Delivery Charge Delta		
$869,221	TOTAL	$869,221	Check total
34,440	Total Retail Customer Delta		
8	Total Transport Customer Delta		
34,448	Total Customer Delta		

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	C20 Cust	C20 Adjustment	C20 Adjusted	C22 Cust	C22 Adjustment	C22 Adjusted	C60 Cust	C60 Adjustment	C60 Adjusted
Jul-07	11,266	436	11,702	15	3	18	5	0	5
Aug-07	11,227	475	11,702	17	1	18	5	0	5
Sep-07	11,232	470	11,702	17	1	18	5	0	5
Oct-07	11,306	396	11,702	17	1	18	5	0	5
Nov-07	11,404	298	11,702	17	1	18	5	0	5
Dec-07	11,558	144	11,702	18	0	18	5	0	5
Jan-08	11,606	96	11,702	14	4	18	5	0	5
Feb-08	11,614	88	11,702	13	5	18	5	0	5
Mar-08	11,570	132	11,702	13	5	18	5	0	5
Apr-08	11,482	220	11,702	13	5	18	5	0	5
May-08	11,420	282	11,702	14	4	18	5	0	5
Jun-08	11,384	318	11,702	14	4	18	5	0	5
Totals	137,069	3,361	140,430	182	37	219	60	0	60

Month	C20 Delta Customer Charge	C22 Delta Customer Charge	C60 Delta Customer Charge
Jul-07	$5,892	$323	$1
Aug-07	$6,419	$123	$1
Sep-07	$6,351	$123	$1
Oct-07	$5,352	$123	$1
Nov-07	$4,029	$123	$1
Dec-07	$1,950	$22	$1
Jan-08	$1,302	$423	$1
Feb-08	$1,194	$523	$1
Mar-08	$1,788	$523	$1
Apr-08	$2,976	$523	$1
May-08	$3,813	$423	$1
Jun-08	$4,299	$423	$1
Total Customer Charge	$45,369	$3,670	$6
Total Delta Charges per Rate	$190,033	$47,795	$400

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	I30 Cust	I30 Adjustment	I30 Adjusted	I32 Cust	I32 Adjustment	I32 Adjusted
Jul-07	15	2	17	6	0	6
Aug-07	15	2	17	6	0	6
Sep-07	15	2	17	6	0	6
Oct-07	15	2	17	6	0	6
Nov-07	16	1	17	7	-1	6
Dec-07	16	1	17	7	-1	6
Jan-08	20	-3	17	5	1	6
Feb-08	20	-3	17	5	1	6
Mar-08	20	-3	17	5	1	6
Apr-08	20	-3	17	5	1	6
May-08	20	-3	17	5	1	6
Jun-08	20	-3	17	5	1	6
Totals	212	-7	205	68	5	73

Month	I30 Delta Customer Charge	I32 Delta Customer Charge
Jul-07	$29	$5
Aug-07	$29	$5
Sep-07	$29	$5
Oct-07	$29	$5
Nov-07	$15	-$95
Dec-07	$15	-$95
Jan-08	-$39	$105
Feb-08	-$39	$105
Mar-08	-$39	$105
Apr-08	-$39	$105
May-08	-$39	$105
Jun-08	-$39	$105
Total Customer Charge	($90)	$460
Total Delta Charges per Rate	($4,443)	($1,555)

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	PA40 Cust	PA40 Adjustment	PA40 Adjusted	PA42 Cust	PA42 Adjustment	PA42 Adjusted
Jul-07	1,054	23	1,077	5	0	5
Aug-07	1,057	20	1,077	5	0	5
Sep-07	1,058	19	1,077	5	0	5
Oct-07	1,059	18	1,077	5	0	5
Nov-07	1,060	17	1,077	5	0	5
Dec-07	1,065	12	1,077	5	0	5
Jan-08	1,066	11	1,077	5	0	5
Feb-08	1,066	11	1,077	5	0	5
Mar-08	1,066	11	1,077	5	0	5
Apr-08	1,067	10	1,077	5	0	5
May-08	1,064	13	1,077	5	0	5
Jun-08	1,065	12	1,077	5	0	5
Totals	12,747	178	12,925	60	0	60

Month	PA40 Delta Customer Charge	PA42 Delta Customer Charge
Jul-07	$312	$0
Aug-07	$271	$0
Sep-07	$258	$0
Oct-07	$244	$0
Nov-07	$231	$0
Dec-07	$163	$0
Jan-08	$150	$0
Feb-08	$150	$0
Mar-08	$150	$0
Apr-08	$136	$0
May-08	$177	$0
Jun-08	$163	$0
Total Customer Charge	$2,402	$0
Total Delta Charges per Rate	$19,721	$0

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	R10 Delta Therms Charge	R12 Delta Therms Charge
Jul-07	$16,217	$1,483
Aug-07	$16,026	$1,340
Sep-07	$14,835	$1,624
Oct-07	$17,229	$1,424
Nov-07	$22,908	$799
Dec-07	$36,570	$1,122
Jan-08	$49,163	$2,225
Feb-08	$46,660	$183
Mar-08	$44,638	-$1,332
Apr-08	$37,462	-$1,879
May-08	$29,719	-$2,839
Jun-08	$22,248	-$1,838
Total Delta Therm Charge	$353,675	$2,313

Delta Therms Per Rate Month	R10 Delta Therms	R12 Delta Therms
Jul-07	49,594	4,536
Aug-07	49,008	4,099
Sep-07	45,367	4,966
Oct-07	52,689	4,353
Nov-07	70,057	4,035
Dec-07	111,834	5,665
Jan-08	150,345	11,238
Feb-08	142,690	925
Mar-08	136,508	(6,726)
Apr-08	114,563	(9,489)
May-08	90,884	(8,681)
Jun-08	68,036	(5,621)
Totals	1,081,574	9,300

Total all Rates > 1,924,478 Therms < Total all Rates

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	C20 Delta Therms Charge	C22 Delta Therms Charge	C60 Delta Therms Charge
Jul-07	$11,533	$3,207	$101
Aug-07	$13,493	-$2,242	$59
Sep-07	$13,585	-$226	$81
Oct-07	$13,970	$733	$59
Nov-07	$13,499	$830	$30
Dec-07	$11,336	$336	$10
Jan-08	$11,062	$9,708	$9
Feb-08	$9,739	$8,461	$7
Mar-08	$9,933	$6,910	$7
Apr-08	$11,646	$6,267	$8
May-08	$12,980	$5,299	$15
Jun-08	$11,887	$4,843	$9
Total Delta Therm Charge	$144,663	$44,125	$394

Delta Therms Per Rate			60
Month	C20 Delta Therms	C22 Delta Therms	C60 Delta Therms
Jul-07	43,717	18,665	315.9
Aug-07	51,149	(13,048)	185
Sep-07	51,497	(1,318)	253
Oct-07	52,958	4,265	186
Nov-07	51,170	4,830	94
Dec-07	42,972	1,954	31
Jan-08	41,935	56,507	28
Feb-08	36,919	49,249	22
Mar-08	37,652	40,221	23
Apr-08	44,148	36,477	24
May-08	49,204	30,845	46
Jun-08	45,060	28,192	27
Totals	548,382	256,839	1,234

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	I30 Delta Therms Charge	I32 Delta Therms Charge
Jul-07	$559	$1,021
Aug-07	$534	$938
Sep-07	$564	-$64
Oct-07	$1,256	-$641
Nov-07	$889	-$3,104
Dec-07	$1,249	-$428
Jan-08	-$2,760	$56
Feb-08	-$3,754	$67
Mar-08	-$1,449	$46
Apr-08	-$754	$33
May-08	-$462	$32
Jun-08	-$226	$29
Total Delta Therm Charge	($4,353)	($2,015)

Delta Therms Per Rate	30	32
Month	I30 Delta Therms	I32 Delta Therms
Jul-07	2,371.7	10,720.8
Aug-07	2,266	9,851
Sep-07	2,395	(673)
Oct-07	5,333	(6,735)
Nov-07	3,773	(32,609)
Dec-07	5,303	(4,494)
Jan-08	(11,716)	587
Feb-08	(15,932)	709
Mar-08	(6,152)	483
Apr-08	(3,200)	351
May-08	(1,960)	332
Jun-08	(959)	308
Totals	(18,477)	(21,168)

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	PA40 Delta Therms Charge	PA42 Delta Therms Charge
Jul-07	$481	$0
Aug-07	$407	$0
Sep-07	$475	$0
Oct-07	$739	$0
Nov-07	$1,525	$0
Dec-07	$2,310	$0
Jan-08	$3,276	$0
Feb-08	$3,115	$0
Mar-08	$2,258	$0
Apr-08	$1,189	$0
May-08	$992	$0
Jun-08	$552	$0
Total Delta Therm Charge	$17,320	$0

Delta Therms Per Rate Month	RtPA4 PA40 Delta Therms	RtPA PA42 Delta Therms
Jul-07	1,855.5	0.0
Aug-07	1,571	0
Sep-07	1,831	0
Oct-07	2,851	0
Nov-07	5,881	0
Dec-07	8,907	0
Jan-08	12,634	0
Feb-08	12,014	0
Mar-08	8,709	0
Apr-08	4,585	0
May-08	3,824	0
Jun-08	2,130	0
Totals	66,795	0

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Weather Normalization
Test Yeat Ended June 30, 2008

LINE NO.	(A) DESCRIPTION	(B) UNS GAS WEATHER ADJUSTMENT	(C) UNS GAS PROPOSED CUSTOMER COUNT	(D) STAFF PROPOSED CUSTOMER COUNT	(E) PERCENT OF STAFF ANNUALIZED TO COMPANY ANNUALIZED CUSTOMERS	(F) STAFF WEATHER ADJUSTMENT	(G) ADJUSTMENT TO PROPOSED COMPANY WEATHER ADJUSTMENT
1	R10	$ (651,725)	1,499,484	1,537,340	102.525%	$ (668,178.46)	$ (16,453.46)
2	R12	$ (26,564)	84,924	81,660	96.157%	$ (25,543.03)	1,021
3	C20	$ (146,996)	136,608	140,430	102.798%	$ (151,108.63)	(4,113)
4	C22	$ (4,413)	168	219	130.357%	$ (5,752.66)	(1,340)
5	IR60	$ (227)	60	60	100.000%	$ (227.00)	-
6	PA40	$ (48,582)	12,780	12,925	101.135%	$ (49,133.20)	(551)
7	PA42	$ (3,947)	60	60	100.000%	$ (3,947.00)	-
8		$ (882,454)	1,734,084	1,772,694	102.227%	$ (903,890)	(21,436)

Sources:

Column A: UNS Gas Proposed Weather Normalization Adjustment Workpapers
Column B: UNS Gas Proposed Customer Retail Sales Adjustment Workpapers
Column C: Staff's adjustmensts to UNS Gas Customer Adjustment workpapers
Column D: Column D divided by Column C.
Column F: Column E X Column B
Column G: Column F minus column B

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Rate Case Revenue Adjustment
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION	(A) AVERAGE THERMS PER CUSTOMER	(B) PRICE CHANGE PER THERM DEC. 1 2006	(C) CUSTOMER CHARGE CHANGE DEC. 1 2006	(D) STAFF CHANGE IN NUMBER OF CUSTS	(E) REVENUE CHANGE PER CUST CLASS
1	R10	570	0.026600	$1.50	15,133	$ 252,146.05
2	R12	499	0.026490	$0.00	-1360	$ (17,977.17)
3	C20	2,647	0.021800	$2.50	1588	$ 95,604.90
4	C22	218,533	0.016700	$15.00	20	$ 73,290.02
5	I30	33,371	0.023400	$2.50	-15	$ (11,750.72)
6	I32	1,137,376	0.008800	$15.00	-5	$ (50,119.54)
7	PA40	5,504	0.023300	$2.50	60	$ 7,844.59
8	PA42	637,510	0.011400	$15.00	0	$ -
9	IR60	14,467	0.031600	$2.50	0	$ -
AL (REVENUE ADJUSTMENT)						$ 349,038

Sources:

Column A, B, and C: UNS Gas Proposed Customer Retail Sales Adjustment Workpapers
Column D: UNS Gas Proposed Customer Adjustment Workpapers & Staff modifications to that spreadsheet.
Column E: Column A X Column B X Column D plus Column C X Column D.

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Bad Debt Expense
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	Staff TY Adjusted Revenue	$ 54,200,000	Schedule THF - A-1
2	TY Gas Revenues	$ 90,472,202	Company Schedule C-2
3	Total TY Adjusted Revenues	$ 144,672,202	Line 1+ Line 2
4	Uncollectible Rate	0.3468%	Staff Adjustment(A)
5	Uncollectibles Expense	$ 501,752.13	Line 3 * Line 4
6	Uncollectibles per Company	$ 688,379.00	Company W/P(B)
7	Adjustment	$ (186,627)	Line 5 - Line 6

A: See Company Schedule E-1 Line 13. The Company's accrued allowance for Doubtful Accounts increased from $(366,736) at December 31, to $(1,219,587) on June 30, 2008. In order to reduce this accelerating increase in accrued bad debt, the uncollectibles rate is being reduced from .487% to .3468% so that the over accrual.
will be eliminated in three years leaving a 100% reserve at the end of three years.
B: Company bad debt pro forma adjustment detail spreadsheet.

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Fuel Expense Adjustment
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Total Miles		2,960,186	Data Request Resp THF 8.10
2	Average Price/Gallon	$	3.35	Data Request Resp THF 8.10
3	Total Gallons		222,973	Data Request Resp THF 8.10
4	Total Cost	$	745,346	Data Request Resp THF 8.10
5	Average Price/Gallon '09	$	1.96	Energy Information Admin
6	Total Cost @ '09 price	$	450,747	Line 5 * Line 3
7	Adjustment	$	(294,599)	Line 6 - Line 4

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Postage Expense Adjustment
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Number of Customer Bills		1,739,076	Co. Schedule H-2
2	Increase in Postage Rates '09		$0.02	
3	09 increase in postage rates/Company cust	$	34,782	Line 1 * Line 2
4	Staff Customer Annualization		34,440	Staff Schedule THF - C.1a
5	Staff Customer Annualization Postage	$	15,154	Line 4 * .44
6	Postage Expense Adjustment	$	49,594	Line 3 * Line 5

UNS Gas, Inc.
Docket No. G-04204A-08-0571
AGA Dues Adjustment
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	TEST YEAR 06 AMOUNT	TEST YEAR 06/30/08 AMOUNT	REFERENCE
1	AGA Dues	$ 43,377	$ 45,964	A
2	Percentage Disallowance	3.511%	3.511%	B
3	Disallowance	$ 1,523	$ 1,614	C
4	Adjustment		$ (1,614)	

Source:
A: Company Filings
B: Disallowance percentage Decision 70011
C: Line 1 * Line 2

UNS Gas, Inc.
Docket No. G-04204A-08-057
Legal Expenses Adjustment
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Company pro forma Adjustment	$	305,984	Company Schedule C.2 p. 4 of 4
2	Adjustment	$	(305,984)	

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Call Center Expense Adjustment
Test Year Ended June 30, 2008

LINE NUMBER	DESCRIPTION	AMOUNT	REFERENCE
1	Average Monthly Allocation 2005	$ 76,227	A
2	Total Call Center Allocation 2005	$ 914,724	Line 1 * 12
3	Total Call Center Allocation - Test Year	$ 1,399,522	DR Response THF 8.4
4	Adjustment	$ (484,798)	Line 2 - Line 3

Source:
A: UNS Decision 70011

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Interest Synchronization
Test Year Ended June 30, 2008

Test Year Ended June 30, 2008		Amount	Reference
A.	Adjusted Rate Base	$178,576,365	1
B.	Weighted cost of Debt	3.24%	2
C.	Synchronized Interest Deduction	$5,785,874	A x B
D.	Synchronized Interest Deduction per UNS Gas	$5,924,526	3
E.	Difference increased interest deduction	$138,652	C - D
F.	Combined Federal and State Income Tax Rates	39.60%	4
G.	Increase to Income Tax Expense	$54,906	E x F

Sources
1. Schedule B-1, Page 1 of 1, Line 18
2. Schedule D-1, Page 1 of 2, Line 2
3. Schedule B-5, Page 3 of 3, Line 18
4. Schedule G-4, Page 26 of 30, Line 25+29

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Intercompany Incentive Compensation Adjustment PEP
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	A COMPANY AMOUNT	B DISALLOWANCE PERCENTAGE	C STAFF ADJUSTED AMOUNT
1	Incentive Comp TY end June '08	$ 125,492	50.00%	$ 62,746
2	Executive Comp and Bene TY 6/08	$ 109,295	50.00%	$ 54,648
3	Total	$ 234,787	50.00%	$ (117,394)

Source:

A: Data Request response THF 8.4
B: From Decision 70011
C: Column A * Column B

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Intercompany Incentive Compensation Adjustment SERP
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	SERP Amount	$	310,278	From Company Workpapers
2	SERP Adjustment	$	(310,412.00)	Decision 70011

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Payroll tax expense, PEP incentive
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	PEP Incentive Disallowance	$	117,393	Schedule THF - C.12
2	Payroll tax expense PEP	$	11,739	10%
3	Adjustment	$	11,739	

CORRECTED PRO FORMA ADJUSTMENT FOR STAFF DATA REQUEST TF 6.68

ADJUSTMENT NAME:	Rate Case Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	April 8, 2009
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs
REVIEWED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
928	Regulatory Expense (A)	$33,333	
928	Regulatory Expense (B)	$166,667	
407	**Amortization of Regulatory Assets - Rate Case Expense**		**$58,333**
	ENTRY TOTAL	**$200,000**	**$58,333**
	NET ENTRY	**$141,667**	

Reason for Adjustment

A) To include rate case expense approved in ACC Decision No. 70011 for the 2006 rate case.

B) To include an estimate of outside expenditures for the rate case expense amortization for $500,000 total expense amortized over 3 years @ $166,667 per year.

Addition to Original Pro Forma to correct test year expense

C) To remove test year amortization of rate case expense for $200,000 of the $300,000 allowed in ACC Decision No. 70011 for the 2006 rate case that will be recovered prior to new rates becoming effective.

Note: Pro forma adjustments related to the write-off 2006 rate case expense not included in the $300,000 allowed in ACC Decision No. 70011 are included in the pro forma adjustment for Miscellaneous Expenses.

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Customer Class Risk Analysis
Test Yeat Ended June 30, 2009

LINE NO.	DESCRIPTION	Coefficient of Variation Decatherms Time Series, TSCI TSCI/TS	Raw Data
1	Residential Service	14.614	74.847
2	Commercial Gas Service	13.317	49.772
3	Industrial Gas Service	36.713	43.804
4	Public Authority Gas Servic	14.686	78.205
5	Total Company	13.497	66.988

References.
Coefficient of Variation = Standard Deviation/Mean

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Summary of Revenues by Customer Class
Adjusted Present Rates and Proposed Rates
Test Yeat Ended June 30, 2010

LINE NO.	DESCRIPTION	(A) COMPANY PRESENT NET REVENUE	(B) COMPANY PROPOSED NET REVENUE	(C) COMPANY PROPOSED NET INCREASE	(D) COMPANY PROPOSED % INCREASE	(E) STAFF PRESENT NET REVENUE	(F) STAFF PROPOSED NET REV	(G) STAFF PROPOSED NET INCRSE	(H) STAFF PROPOSED % INCRSE
1	Residential Service	$ 36,381,453	$ 43,056,622	$ 6,675,169	18.348%	$ 37,432,308	$ 39,777,559	$ 2,345,251	6.265%
2	Commercial Gas Service	$ 9,818,220	$ 11,689,364	$ 1,871,144	19.058%	$ 10,302,730	$ 10,927,395	$ 624,665	6.063%
3	Industrial Gas Service	$ 255,152	$ 303,253	$ 48,101	18.852%	$ 186,135	$ 278,720	$ 92,585	49.741%
4	Public Authority Gas Service	$ 1,779,079	$ 2,117,900	$ 338,821	19.045%	$ 1,812,092	$ 1,961,563	$ 149,471	8.249%
5	Special Gas Light Service	$ 66,940	$ 79,706	$ 12,766	19.071%	$ 66,940	$ 71,107	$ 4,167	6.225%
6	Irrigation Service	$ 33,865	$ 40,322	$ 6,457	19.067%	$ 33,865	$ 35,972	$ 2,107	6.222%
7	Transportation Customers	$ 2,823,056	$ 3,351,473	$ 528,417	18.718%	$ 2,823,066	$ 2,999,243	$ 176,177	6.241%
8	Subtotal	$ 51,157,765	$ 60,638,640	$ 9,480,875	18.533%	$ 52,657,136	$ 56,051,559	$ 3,394,423	6.446%
9	Other Operating Revenue	$ 1,744,743	$ 1,744,743	$ -	0.000%	$ 1,744,743	$ 1,744,743	$ -	0.000%
10	Total	$ 52,902,508	$ 62,383,383	$ 9,480,875	17.921%	$ 54,401,879	$ 57,796,302	$ 3,394,423	6.240%

References:
Columns (A), (B), (C) and (D) Company H-2(P2)

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Comparison of Revenues by Rate Schedules
Adjusted Present Rates and Proposed Rates
Test Yeat Ended June 30, 2010

LINE NO.	DESCRIPTION	(A) COMPANY ADJUSTED NET REVENUE	(B) COMPANY PROPOSED INCREASE	(C) COMPANY PROPOSED NET REVENUE	(D) STAFF ADJUSTED NET REVENUE	(E) STAFF PROPOSED INCREASE	(F) STAFF PROPOSED NET REVENUE
1	Residential Service	$ 35,003,749	$ 6,675,169	$ 41,678,918	$ 36,125,387	$ 2,335,687	$ 38,461,074
2	Residential Service - CARES	$ 1,377,705	$ -	$ 1,377,705	$ 1,306,921	$ -	$ 1,306,921
3	Small volume commercial	$ 9,571,509	$ 1,825,274	$ 11,396,783	$ 10,030,325	$ 614,202	$ 10,644,527
4	Large volume commercial	$ 246,710	$ 45,870	$ 292,580	$ 272,405	$ 16,681	$ 289,086
5	Commercial Transportation	$ 533,224	$ 102,862	$ 636,086	$ 533,221	$ 33,607	$ 566,828
6	Small volume industrial	$ 133,707	$ 25,498	$ 159,205	$ 91,458	$ 45,959	$ 137,417
7	Large volume industrial	$ 121,445	$ 22,603	$ 144,048	$ 94,650	$ 47,548	$ 142,198
8	Industrial transportation	$ 1,118,256	$ 213,806	$ 1,332,062	$ 1,118,216	$ 70,479	$ 1,188,695
9	Industrial transportation - contracts	$ 451,464	$ 86,094	$ 537,558	$ 451,408	$ 28,451	$ 479,859
10	T2 Transportation	$ 63,852	$ 80	$ 63,932	$ 65,777	$ 4,146	$ 69,923
11	Small volume public authority	$ 1,630,262	$ 310,889	$ 1,941,151	$ 1,660,873	$ 138,353	$ 1,799,226
12	Large volume public authority	$ 148,817	$ 27,932	$ 176,749	$ 151,219	$ 12,605	$ 163,824
13	Public Authority Transportation	$ 656,260	$ 125,595	$ 781,855	$ 654,471	$ 41,369	$ 695,840
14	Special gas light services	$ 66,940	$ 12,766	$ 79,706	$ 66,940	$ 4,208	$ 71,148
15	Irrigation service	$ 33,865	$ 6,458	$ 40,323	$ 33,865	$ 2,128	$ 35,993
16	Total gas service	$ 51,157,765	$ 9,480,896	$ 60,638,661	$ 52,657,136	$ 3,395,423	$ 56,052,559

References:
Columns (A), (B), (C) and (D) Company H-2(P2)

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Summary of Staff Recommended Rate Design
Test Yeat Ended June 30, 2009

LINE NO.	CLASS OF SERVICE	Current Rates	Proposed Rates	Change
1	**Residential Service R(10)**			
2	Customer Charge	$8.5000	$9.5000	$1.0000
3	Distribution Margin Therms	$0.3270	$0.3383	$0.0113
4	**Small Commercial Service (C20)**			
5	Customer Charge	$13.5000	$15.5000	$2.0000
6	Distribution Margin Therms	$0.2638	$0.2746	$0.0108
7	**Large Commercial Service (C22)**			
8	Customer Charge	$100.0000	$105.0000	$5.0000
9	Distribution Margin Therms	$0.1718	$0.1825	$0.0107
10	**Small Volume Industrial Service (I-30)**			
11	Customer Charge	$13.5000	$15.5000	$2.0000
12	Distribution Margin Therms	$0.2356	$0.2556	$0.0200
13	**Large Volume Industrial Service (I-32)**			
14	Customer Charge	$100.0000	$105.0000	$5.0000
15	Distribution Margin Therms	$0.0952	$0.1152	$0.0200
16	**Small Volmune PA ((PA-40)**			
17	Customer Charge	$13.5000	$15.5000	$2.0000
18	Distribution Margin Therms	$0.2593	$0.2789	$0.0196
19	**Large Volume PA (PA-42)**			
20	Customer Charge	$100.0000	$105.0000	$5.0000
21	Distribution Margin Therms	$0.1198	$0.1300	$0.0102
22	**Special Gas Light Service (PA-44)**			
23	Single Office	$23.7200	$23.0100	-$0.7100
24	Double Office	$39.5300	$40.7200	$1.1900
25	Triple Office	$54.8600	$58.1000	$3.2400
26	Quadruple Office	$71.1800	$76.1400	$4.9600
27	**Irrigation Service (IR-60)**			
28	Customer Charge	$13.5000	$15.5000	$2.0000
29	Distribution Margin Therms	$0.3192	$0.3386	$0.0194

S Gas, Inc.
G-04204A-08-0571
f of Revenue
nded June 30, 2010

Line No.	Description	Element	Present Rates	Billing Units	Adjusted Present Revenue	Proposed Rates	Proposed Revenue
1	Residential R10	Customer Charge	$8.5000	1,537,340	$13,067,390.00	$9.5000	$14,604,730.00
2		Distribution Margin	$0.3270	70,513,752	$23,057,996.90	$0.3383	$23,856,344.00
3					$36,125,386.90		$38,461,074.00
4	Residential R12	No change	No change	81,660	$1,306,921.00		$1,306,921.00
5	Small Commercial C-20	Customer Charge	$13.5000	140,430	$1,895,805.00	$15.5000	$2,176,665.00
6		Distribution Margin	$0.2638	30,835,936	$8,134,519.92	$0.2746	$8,467,862.00
7					$10,030,324.92		$10,644,527.00
8	Large Commercial C-22	Customer Charge	$100.0000	219	$21,900.00	$105.0000	$22,995.00
9		Distribution Margin	$0.1718	1,458,120	$250,505.02	$0.1825	$266,091.00
10					$272,405.02		$289,086.00
11	Small Industrial I-30	Customer Charge	$13.5000	240	$3,240.00	$15.5000	$3,720.00
12		Distribution Margin	$0.2356	523,052	$88,218.06	$0.2556	$133,692.00
13					$91,458.06		$137,412.00
14	Large Industrial I-32	Customer Charge	$100.0000	73	$7,300.00	$105.0000	$7,665.00
15		Distribution Margin	$0.0952	1,167,821	$87,350.00	$0.1152	$134,533.00
16					$94,650.00		$142,198.00
17	Smal Public Authority PA-40	Customer Charge	$13.5000	12,925	$174,487.50	$15.5000	$200,337.50
18		Distribution Margin	$0.2593	5,732,300	$1,486,385.39	$0.2789	$1,598,888.50
19					$1,660,872.89		$1,799,226.00
20	Large Public Authority PA-42	Customer Charge	$100.0000	60	$6,000.00	$105.0000	$6,300.00
21		Distribution Margin	$0.1198	1,212,179	$145,219.04	$0.1300	$157,524.00
22					$151,219.04		$163,824.00
23	Gas Lighting PA-44		$18.1100	3,696	$66,934.56	$19.2500	$71,148.00
24	Large Industrial I-32	Customer Charge	$13.5000	60	$810.00	$15.5000	$930.00
25		Distribution Margin	$0.3192	103,554	$33,054.44	$0.3386	$35,063.00
26					$33,864.44		$35,993.00

Residential Service R10

Customer Charge	$8.50	$9.50
Distribution Margin Therms	$0.3270	$0.3383

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
5	$10.14	$11.19	$1.06	10.424%
10	$11.77	$12.88	$1.11	9.456%
20	$15.04	$16.27	$1.23	8.152%
35	$19.95	$21.34	$1.40	6.997%
50	$24.85	$26.42	$1.57	6.298%
75	$33.03	$34.87	$1.85	5.594%
100	$41.20	$43.33	$2.13	5.170%
250	$90.25	$94.08	$3.83	4.238%
500	$172.00	$178.65	$6.65	3.866%

Small Commercial Service C20

Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2638	$0.2746

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
50	$26.69	$29.23	$2.54	9.517%
100	$39.88	$42.96	$3.08	7.723%
500	$145.40	$152.80	$7.40	5.089%
1000	$277.30	$290.10	$12.80	4.616%
1500	$409.20	$427.40	$18.20	4.448%
2500	$673.00	$702.00	$29.00	4.309%
5000	$1,332.50	$1,388.50	$56.00	4.203%
7500	$1,992.00	$2,075.00	$83.00	4.167%
1000	$277.30	$290.10	$12.80	4.616%

Large Commercial Service C22

Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.1718	$0.1825

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
10001	$1,818.17	$1,930.18	$112.01	6.161%
12500	$2,247.50	$2,386.25	$138.75	6.174%
17500	$3,106.50	$3,298.75	$192.25	6.189%
20000	$3,536.00	$3,755.00	$219.00	6.193%
25000	$4,395.00	$4,667.50	$272.50	6.200%
30000	$5,254.00	$5,580.00	$326.00	6.205%
45000	$7,831.00	$8,317.50	$486.50	6.212%
75000	$12,985.00	$13,792.50	$807.50	6.219%

Small Volume Industrial Service I30

Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2356	$0.2556

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
50	$25.28	$28.28	$3.00	11.867%
100	$37.06	$41.06	$4.00	10.793%
500	$131.30	$143.30	$12.00	9.139%
1000	$249.10	$271.10	$22.00	8.832%
1500	$366.90	$398.90	$32.00	8.722%
2500	$602.50	$654.50	$52.00	8.631%
5000	$1,191.50	$1,293.50	$102.00	8.561%
7500	$1,780.50	$1,932.50	$152.00	8.537%
10000	$2,369.50	$2,571.50	$202.00	8.525%

Large Volume Industrial Service I32

Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.0952	$0.1152

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
10001	$1,052.10	$1,257.12	$205.02	19.487%
12500	$1,290.00	$1,545.00	$255.00	19.767%
17500	$1,766.00	$2,121.00	$355.00	20.102%
20000	$2,004.00	$2,409.00	$405.00	20.210%
25000	$2,480.00	$2,985.00	$505.00	20.363%
30000	$2,956.00	$3,561.00	$605.00	20.467%
45000	$4,384.00	$5,289.00	$905.00	20.643%
75000	$7,240.00	$8,745.00	$1,505.00	20.787%

Small Volume Public Authority PA40

Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2593	$0.2789

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
50	$26.47	$29.45	$2.98	11.260%
100	$39.43	$43.39	$3.96	10.043%
500	$143.15	$154.95	$11.80	8.243%
1000	$272.80	$294.40	$21.60	7.918%
1500	$402.45	$433.85	$31.40	7.802%
2500	$661.75	$712.75	$51.00	7.707%
5000	$1,310.00	$1,410.00	$100.00	7.634%
7500	$1,958.25	$2,107.25	$149.00	7.609%
1000	$272.80	$294.40	$21.60	7.918%

Large Public Authority Service PA42

Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.1198	$0.1300

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
10001	$1,298.12	$1,405.13	$107.01	8.243%
12500	$1,597.50	$1,730.00	$132.50	8.294%
17500	$2,196.50	$2,380.00	$183.50	8.354%
20000	$2,496.00	$2,705.00	$209.00	8.373%
25000	$3,095.00	$3,355.00	$260.00	8.401%
30000	$3,694.00	$4,005.00	$311.00	8.419%
45000	$5,491.00	$5,955.00	$464.00	8.450%
75000	$9,085.00	$9,855.00	$770.00	8.476%

Irrigation Service IR60

Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.3192	$0.3386

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
50	$29.46	$32.43	$2.97	10.081%
100	$45.42	$49.36	$3.94	8.675%
500	$173.10	$184.80	$11.70	6.759%
1000	$332.70	$354.10	$21.40	6.432%
1500	$492.30	$523.40	$31.10	6.317%
2500	$811.50	$862.00	$50.50	6.223%
5000	$1,609.50	$1,708.50	$99.00	6.151%
7500	$2,407.50	$2,555.00	$147.50	6.127%
10000	$3,205.50	$3,401.50	$196.00	6.114%

EXHIBIT
S-13
ADMITTED
ALL-STATE LEGAL®

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. G-04204A-08-0571

SURREBUTTAL

TESTIMONY

OF

THOMAS H. FISH, PH.D.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 29, 2009

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EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NO. G-04204A-08-0571

My Surrebuttal Testimony addresses the Company's proposed revenue requirement and pro forma adjustments to rate base and operating revenue. I also respond to the Rebuttal testimony of UNS Gas, Inc. witnesses Hutchens, Grant, Erdwurm, Dukes, and Kissinger.

Staff now recommends a revised total operating income of $13,236,581, with an associated operating income deficiency of $2,166,054, and a gross revenue requirement of $3,539,982.

	Original	Surrebuttal
	Pro Forma	Modified Pro
Description	Adjustment	Forma Adjustment
	Rate Base Pro Forma Adjustment	
ADIT	$38,994	0
	Revenue Pro Forma Adjustments	
Payroll Tax	$(11,739)	$(8,780)
Postage	$(49,594)	$(49,247)
AGA Dues	$(1,614)	0
SERP	$(310,412)	$(101,021)
Fuel Expense	$(308,381)	$(226,352)
Synchronized Interest	$54,906	0
Bad Debt	$(186,625)	$(185,927)
Operating revenue deficiency	$2,077,601	$2,166,054
Increase in gross revenue requirement	$3,395,423	$3,539,982

INTRODUCTION

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

A. Thomas H. Fish. I am president of Ariadair Economics Group, 1020 Fredericksburg Rd. Excelsior Springs, MO 64024.

Q. Are you the same Thomas H. Fish who filed direct testimony in this case on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff")?

A. Yes.

Q. What is the purpose of your Surrebuttal testimony?

A. The purpose of my testimony is to respond to selected issues that were presented in the Rebuttal Testimony of UNS Gas, Inc. ("UNS Gas" or "UNS") witnesses Hutchens, Grant, Erdwurm, Dukes, and Kissinger.

RATE BASE ADJUSTMENTS

Post-Test Year Plant

Q. Did Staff propose a pro forma adjustment for Post-Test Year Plant in Service?

A. Yes. The Company proposed a pro forma adjustment to place $1,527,588 of post-test year Plant in Service in rate base. Staff offered a pro forma adjustment to remove that amount from the Company's proposed rate base.

Q. Did the Company, in its Rebuttal Testimony, respond to Staff's proposed removal of its post-test year Plant in Service?

A. Yes.

Q. What was the Company's response?

A. The Company witness, Mr. Dukes, proposed that certain post-test year Plant in Service should remain in rate base. He stated (page 5, lines 6-8 of his Rebuttal Testimony) that "The Plant accounting group and operational personnel of UNS Gas reviewed the projects and identified investments that had been made in projects that would not produce additional revenue and that would have been invested in regardless of customer growth." The Company argues that it is not fair to have made the capital investment, which the Company alleges is necessary for the provision of service and, due to unfortunate timing, not be allowed to include it in rate base.

Q. Is the inclusion of post-test year plant up to the discretion of the Commission?

A. Yes. There are specific instances where the Commission has allowed a utility to include post-test year plant in rate base. Typically, Staff does not recommend the inclusion of post-test year plant in rate base.

Q. Are there instances where Staff has recommended the inclusion of post-test year plant?

A. Although Staff typically does not recommend the inclusion of post-test year plant in rate base unless the utility has demonstrated a compelling need, Staff has recognized the following situations that may warrant the inclusion of post-test-year plant:

- When the magnitude of the investment relative to the utility's total investment is such that not including the post-test year plant in the cost of service would jeopardize the utility's financial health;
- When the cost of the post-test year plant is significant and substantial;
- The net impact on revenue and expenses for the post-test year plant is known and insignificant, or is revenue neutral; and

- The post-test year plant is prudent and necessary for the provision of services and reflects appropriate, efficient, effective and timely decision-making.

Q. Are there other problems with allowing the inclusion of post-test year plant?

A. Yes. Post-test year plant is usually mismatched with the revenues, expenses and the rate base of the test year. Revenues and expenses associated with post-test year plant are not quantifiable and thus create the mismatch.

Customer Advances Adjustment

Q. Does Staff agree with the Company's rationale regarding customer advances?

A. No. Customer advances represent non-investor-supplied capital and as such they should be reflected as a deduction to rate base. In addition, A.A.C. R-14-2-103 requires that those funds be deducted from rate base.

Working Capital

Q. Please describe Staff's cash working capital pro forma adjustment.

A. Staff noticed an anomaly in the Company's payment to British Petroleum ("BP") that reduced the payment day lag to only 17.83 days for three months, not the normal 35 days. The lag for payment for purchased gas reduced the average monthly payment lag to 27.89 days. Staff made a corresponding adjustment to account for the reduction in the average payment lag and for the impact of the other proposed adjustments to operating revenue and expenses which resulted in an adjustment to working capital requirements of $(1,624,840).

Q. Did the Company address Staff's cash working capital pro forma adjustment in its Rebuttal Testimony?

A. Yes. In his Rebuttal Testimony, Mr. Dukes made an additional cash working capital adjustment from his original $97,967 to $2,183,948. On page 8, lines 14-19, Mr. Dukes states:

"The payment lag is actually much shorter than the 35 days used by Staff. In fact, the payments made to that vendor early in the test year were not reflective of payment terms later in the test year or of the current payment terms. The Company's payment terms were altered during the test year because of credit limitations. The vendor now requires the Company to make payments twice a month and those payment requirements continue today and for the foreseeable future."

Mr. Dukes goes on to say, page 8, lines 23-27:

"In the Company's original filing, the new payment terms were only partially reflected in the Company's lead lag study. The changed payment schedule remains in place and is therefore a "known and measurable" change. Thus the Company is making an alternative adjustment in its rebuttal filing to fully reflect all purchased gas payments to that vendor with the proper payment lags."

Q. Should the Company's rate payers be responsible for the incremental cost of purchased gas associated with the timing of the payments?

A. No. Staff's position is that the Company's 12-day payments (including 7.5 day mid-point correction) is not realistic and is not representative of normal credit terms. Although the Company may accept these terms from BP, such terms are not normal or reasonable. UNS has the discretion to obtain more favorable terms and conditions from another supplier.

Reconstruction Cost New Depreciated ("RCND") Study

Q. How does the Company describe Staff's analysis and evaluation of its RCND study?

A. The Company has alleged that Staff mischaracterized its RCND study in the prior rate case (Docket No. G-04204A-06-0463 et al.) as being conservative when it was not. Company witness Dukes (Rebuttal Testimony at page 9, lines 4-11) states:

> "Dr. Fish incorrectly implies in his Direct Testimony (at page 13, lines 1-11) that the Company took an extremely conservative approach in deriving its RCND study in the last rate case to keep the value of the RCND down. In fact, if the present RCND was done in this case consistent with the prior case, the Company would have presented an RCND value of approximately $22.2 million (this amount was subsequently reduced to $16 million) greater than the one filed in my Direct Testimony. Therefore, the Company took a more conservative approach in this filing when compared to the previous filing."

Q. Do you agree with Mr. Dukes interpretation of your evaluation of the Company's RCND Study?

A. No.

Q. Please explain.

A. The Company made several errors in its previous study which resulted in an understatement of the RCND rate base. The Company has used an extremely aggressive approach to calculating its trend values for Mains (Federal Energy Regulatory Commission ("FERC") account 376) and for Services (FERC account 380) in its RCND study in this proceeding.

The value (purchasing power) of money changes over time so that dollars to be received in the future can generally be expected to have less value than today's dollars and dollars received in the past can generally be expected to have had greater value than today's dollars. This is an important concept, since a fundamental step in a RCND study is the

initial one of making all dollars spent on a utility system have the same value. The initial task is to create what the Company calls "trend values" which, as explained in my Direct Testimony, are created by dividing the ending index value (base period value) by each of the series of index values in the study. The validity of the trend value depends upon the analyst making sure that the base index value (test year) is chosen correctly.

In the previous RCND study, the Company used the wrong base period. Thus, the RCND value in the previous case was understated by about 25 percent, which, in turn, understated the fair value rate base by about 12.5 percent. In the RCND study the Company conducted for this case, it does not appear that the Company made the same mistake of using the wrong base period value to derive trend values.

Q. Do you have additional information you would like to provide?

A. Yes. In my telephone discussion with Mr. Dukes in May 2009, I asked, with regard to the RCND study in the prior rate case, why the Company did not separate out the Mains (FERC 376) by plastic, steel, and cast iron, since those indices are available from Handy-Whitman. I also asked why the Company labeled the index column Handy-Whitman Index, Section G-5, Line 43 (cast iron) but used Line 44 (steel) values. Mr. Dukes explained that when the assets of Citizens Utilities were acquired by UniSource, Citizens' records were scattered. He said that the Citizens office in New Orleans was searched for accounting records and that the search was extended to include the garages of Citizens employees in New Orleans. As a result of the poor record keeping by Citizens, the Company simply did not have the detailed records that would allow a precise determination of RCND at that detailed level to be made. Mr. Dukes explained that as a consequence the Company tried to take a conservative approach in its RCND study effort. In my opinion, under those conditions, a conservative approach was probably best.

Q. Why do you conclude that the Company is using an aggressive approach in this RCND study?

A. The Company claims that if its RCND study in this case were consistent with that of the previous case, the value of the RCND would be approximately $22 million (amended to $16 million) greater than the one filed. Unfortunately, Mr. Dukes did not define what he meant by the word "consistent." If the Company had used the same procedure as in its previous rate case, its RCND would have been smaller than the one presented because in the last rate case the Company used a base index in the year before the test year, not the index in the test year. In the RCND study presented in this case, the base index the Company used for Mains (steel) was 565 and in the previous year it was 555. The calculated trend values would have been smaller and the resulting reconstructed values also smaller had the Company made the same error (been consistent with) the procedure used in the previous case.

In addition, the Handy-Whitman index values for January 1, 2008 for Cast Iron Mains was 472, for Steel Mains was 565, and for plastic Mains was 438. The Company applied the index value for Steel Mains to its entire system, and the index value for Steel Mains was 18 percent above that of Cast Iron Mains and 29 percent above that of Plastic Mains. Since FERC 376 is such a large component of rate base, unless the Company really does have 100 percent Steel Mains, it has surely overstated RCND rate base and, by extension, Fair Value Rate base. (Note that Handy-Whitman provided only cast iron and steel index values for FERC Account 376 until 1962 when it started to provide an index value for Plastic Mains in addition to steel and cast iron.) But since, according to Mr. Dukes, the Company does not have the records necessary for precise calculation, we cannot know for sure.

Customer Class Risk Study

Q. Does the Company address Staff's customer class risk study in its Rebuttal Testimony?

A. Yes. Company witness Erdwurm (Rebuttal Testimony at page 14, lines 1-2) complains that the customer class study "...contains no usable sensitivity analysis, and as presented, only serves to obscure the degree of financial risk this Company faces."

Q. Do you agree with Mr. Erdwurm's criticism of Staff's customer class risk study?

A. No. The customer class risk study was designed to capture unanticipated changes in consumption, not as a sensitivity analysis of the Company's financial risk. This was accomplished by combining classical time series analysis with a comparable coefficient of variation analysis. The study was not designed to address the financial risk of the Company. The Company could have conducted a sensitivity analysis of its financial risk and presented its results. It apparently chose not to do so.

Accumulated Deferred Income Taxes ("ADIT")

Q. Did the Company address Staff's adjustment for ADIT?

A. Yes. Company witness Kissinger stated at page 2, lines 2-7 of her Rebuttal Testimony that the amount disallowed by Staff was not included in the rate base in the Company's Application and, therefore, should not be disallowed.

Q. Does Staff agree with the Company's assertions?

A. Yes. Staff adjusted ADIT to recognize the income tax effects of the Supplemental Executive Retirement Plan ("SERP") adjustment.

OPERATING INCOME ADJUSTMENTS

Rate Case Revenue Annualization

Q. Does the Company address your Rate Case Revenue Annualization adjustment in its Rebuttal Testimony?

A. Yes. Mr. Erdwurm states at page 10, line 24 through page 11, line 3:

> "Moreover, the flaws in Dr. Fish's rate case revenue annualization are compounded; the revenue annualization does not fully adjust test-year revenue for the rate change that occurred within the test-year. It appears that Dr. Fish's adjustment is improperly limited to his overstated customer growth estimate. A rate case annualization adjustment should apply to all test-year sales – not just growth – billed prior to the "within-the-test-year" rate change."

Q. Do you agree with Mr. Erdwurm's criticism?

A. No. Staff believes that its methodology is accurate and appropriate. Please see my direct testimony at pages 22-23.

Customer Annualization

Q. Does the Company agree with Staff's customer annualization technique and outcome?

A. No. The Company alleges that Staff's annualization is flawed.

Q. What are the reasons that the Company gives to support its claim that Staff's annualization method is flawed?

A. Company witness Erdwurm at page 4, lines 11-20 of his Rebuttal Testimony gives the following reasons for his conclusion that Staff's customer annualization is flawed:

1. It adjusts customer counts to levels exceeding not only test-year end, but all months of the test-year, even months beyond the test-year.

2. Applies a future test-year approach to the customer annualization adjustment without applying future test-year methods to all other aspects of the ratemaking process – and thus violates the "matching principle".
3. Uses a significantly overstated and unsupportable customer count growth rate.
4. Fails to adjust customer count to test-year end levels.
5. Is not known and measurable because it uses customer levels that still have not been attained and will not be attained until some unknowable date in the future.

Q. Do you agree with Mr. Erdwurm's conclusions?

A. No.

Q. Can you please address Mr. Erdwurm's allegations?

A. Staff responds as follows:

- Staff's customer annualization adjustment creates test year customers that reflect a level of operating revenues and expenses and net plant investment that is representative of normal conditions that may be expected to exist during the time that resulting rates will be in effect.
- Staff did not apply a future test-year approach to its customer annualization method, as suggested by the Company. Staff utilized historical test year information as provided by the Company.
- Staff used the growth rate provided by the Company.
- Staff did not fail to adjust customer count to test year end levels. Company witness Erdwurm in his Direct Testimony explicitly states that the number of test-year bills should not necessarily equal the exact year-end customer count.

- The Company does not require that year end customer counts for annualization purposes be equal to actual year end customer counts. Therefore, if matching of year-end customer counts with annualization counts is not required for customer annualization purposes.

Q. Does the Company recognize problems with its approach to customer annualization?

A. Yes. According to Mr. Erdwurm, the Company recognized that its customer annualization procedure resulted in invalid and unusable results. "Of the test-year ends during the summer (as in this case June 2008), the test-year end customer count may be less than some of the monthly customer counts during the previous eleven months of the year." (Erdwurm Direct Testimony at page 8, lines 3-5.) In this case, 8 of the previous 11 months had higher customer counts (for R10) and were adjusted downwards by the Company.

Customer Growth

Q. Has the Company presented an inconsistent position with respect to customer growth and the impact on its capital investment?

A. Yes. Company witness Hutchens stated in his Direct Testimony (page 6, lines 19-24):

"As I previously mentioned, UNS Gas has put an additional $54 million of capital investment into service on its distribution and service line facilities since the end of its last rate case test year. Roughly two-thirds of this significant investment has been related to growth in the Company's natural gas system in a number of service area communities in Arizona. The remaining one-third is attributable to UNS Gas' need to upgrade and reinforce its system for existing customers."

Thus, approximately $36 million of the capital investment base is directly associated with customer growth, and about $18 million of the capital investment is for existing

customers. However, other Company witnesses present conflicting information with respect to customer growth.

Q. What conflicting information has the Company presented?

A. Company witness Erdwurm makes the following statements regarding customer growth: "Customer levels that (referring to Staff's customer annualization) still have not been attained and will not be attained *until some unknowable date in the future.*" (At page 4, lines 19-20, emphasis added.) "Dr. Fish's inflated customer count has not yet been achieved by July 8, 2009 and will not be achieved *until some indeterminate time in* achieved until far after the test-year. . ." (At page 5, lines 17-18) "There has been no "major customer addition" . . ." (At page 6, line 8) " . . .more than a year after the close of the test-year, UNS Gas has not reached this inflated customer count *and may not reach it for some significant time to come.*" (At page 6, lines 21-22, emphasis added.) The Company further states in Mr. Edwurm's testimony: "Dr. Fish should never have pressed forward with his methodology, since he should have known the customer level to which he was adjusting had never occurred, *nor would it occur, even over a period one year after the end of the test year.*" (At page 7, lines 22-25, emphasis added.) It appears that the Company has changed its position from a growing system to a no-growth system since this rate application was filed.

Q. Does the Company offer support that it has no customer growth?

A. Yes. The Company seems to be reversing its position on customer growth and has decided that it does not know when customer growth may actually reach customer annualization levels of the test year. To support this position, Mr. Erdwurm provides two tables: Residential rate R10 customer counts (Exhibit DBE-3, pages 1 and 2) and Commercial rate C20 customer counts (Exhibit DBE-3, pages 5 and 6). Mr. Erdwurm

uses these schedules as support for his contention that there is no customer growth on the UNS Gas System. He shows that the May 2009 R10 customer bill count was 124,203, down from the December 2006 count of 125,383, and the May 2009 C20 count of 11,356 was down from the December 2006 count of 11,435.

Q. What conclusions do you reach from this information provided by the Company?

A. It is clear that existing customers are being asked to pay for $36 million in capital investment that is not necessary for the Company's provision of service to them. That investment, according to the Company, was made to provide service to customers who do not exist and, according to the Company, may or may not exist at some time in the future. Staff requested information concerning the Company's capital investment and depreciation as well as for monthly customer count by rate group, but the Company did not provide it in response to Staff's data request.(See the Company response to Staff data requests TF 6.4 and TF 6.5, also Staff response to Company request UNSG 4.23). This investment, according to the Company, certainly cannot be considered to be used and useful in the provision of service to the Company's remaining customers. It appears that there is no customer benefit to the investment because the growth did not materialize.

Q. Are there other factors that might be considered in evaluating the $36 millioncapital investment made for customer growth that has failed to materialize?

A. Yes. After the Company filed its application for rate relief, the economy took a turn for the worse. The residential real estate market suffered a setback, various financial sectors of the economy experienced some reversals, and the rate of growth in the number of the Company's customers appears to have slowed. The Company appears to have not forecast and considered these factors in making its capital investment decisions related to customer growth.

Weather Normalization

Q. Did the Company address Staff's weather normalization adjustment?

A. Yes. Mr. Erdwurm, in his Rebuttal testimony at page 10, lines 22-24, argues that since Staff's customer annualization is flawed, Staff's weather normalization must have flaws as well.

Q. Do you agree with Mr. Erdwurm's assessment?

A. No. Staff's customer annualization, as demonstrated in detail above, is correct. Because Staff's customer annualization is correct, Staff's weather normalization adjustment is correct.

Fair Value Component of Revenue Requirement

Q. Does the Company address Staff's treatment of Fair Value in your Schedule THF-A1?

A. Yes. At page 29, lines 3-4 of Company witness Grant's Rebuttal Testimony, Mr. Grant states that "Indeed, even Staff seems to concede that this (0 percent return on fair value increment) is inappropriate. He contends that Staff's revenue requirement does not follow Mr. Parcell's "primary recommendation" and he cites Schedule THF-A1. The Staff fair value adjustment of Schedule THF-A1 is not a comment on the process involved in deriving the fair value adjustment, but simply follows the direction of Staff witness Parcell with respect to incorporating Mr. Parcell's fair value adjustment into the Company's revenue requirement in that Schedule.

OPERATING EXPENSE ADJUSTMENTS

Payroll Tax Expense

Q. Dr. Fish, do you propose a modification to the pro forma payroll tax expense adjustment?

A. Yes. Schedule THF – C16 shows line No. 1 referring to Schedule THF – C12. The correct reference should be Schedule THF – C14. In addition, the correct adjustment should be $8,981, not $11,739.

Incentive Compensation

Q. Did the Company address Staff's pro forma adjustments for employee incentive compensation in its Rebuttal Testimony?

A. Yes. Mr. Dukes, at pages 12 through 15, suggests that the Company be allowed to recover all of the PEP incentive compensation. Staff had made a pro forma adjustment of one half of PEP expenses because the benefits accrued to both ratepayers and owners of the Company.

Q. Do you agree with Mr. Dukes that the Company should be allowed to recover all of its PEP expenses in rates?

A. No. Mr. Dukes does not provide evidence that ratepayers enjoy all of the benefits associated with PEP.

Q. Does the Company take exception to Staff's pro forma adjustment for SERP in its Rebuttal Testimony?

A. Yes. SERP is a supplemental retirement plan for select employees that exceed IRS retirement limits. Staff recommended that those expenses be eliminated from revenue requirement. Mr. Dukes, at page 18, lines 22-24 states: "It simply keeps those individuals

whose compensation level exceeds deductibility levels equal to those individuals whose compensation does not."

Q. Do you agree with Mr. Dukes' arguments to include SERP expenses in rates?

A. No. Staff does not advocate that the SERP plan not be available to Company executives only that owners, not ratepayers, fund it.

Q. Do you propose a modification for Staff's SERP adjustment?

A. Yes. The original adjustment was $310,412. The amount was taken from the Company's lead lag study work papers. That amount, however, included both SERP and PEP expenses and, therefore, overstated the SERP expense. The SERP expense should be $101,021.

AGA Dues

Q. Did the Company address Staff's adjustment for membership dues for the American Gas Association ("AGA")?

A. Yes. Mr. Dukes, of page 21 of his rebuttal testimony, stated that Staff's adjustment was unnecessary.

Q. Do you agree?

A. Yes. The AGA Dues pro forma adjustment of $1,614 should be eliminated.

Postage Expense

Q. Was there a mathematical error in Staff's postage expense pro forma adjustment?

A. Yes. Staff's customer annualization resulted in 34,440 more customer bills than the Company's customer annualization. These additional customers would require postage

for their bills. Two cents of the total postage for the additional customers is accounted for in line 3 of Schedule THF – C9, but $0.42 of the postage for the additional customers is not accounted for and should be. This amount is $14,465. The total postage pro forma adjustment, then, is $34,782 from line 3 plus $14,465 for a total pro forma adjustment of $49,247, not $49,594.

Normalize Outside Legal Expenses

Q. Did the Company claim that Staff erred in its pro forma adjustment for legal expenses?

A. Yes. Mr. Dukes, at page 27 of his Rebuttal Testimony, claims that Staff provided no substantive reason for the pro forma adjustment.

Q. Do you agree?

A. No. Mr. Dukes has provided no substantive reasons for the high level of legal expenses he seeks nor has the Company offered any evidence that it is attempting to mitigate its legal expense. Absent this evidence by the Company, Staff's pro forma adjustment should be accepted by the Commission.

Bad Debt Expense

Q. Does the Company address Staff's proposed bad debt expense in its Rebuttal Testimony?

A. Yes. The Company claims that Staff is in error because Staff's pro forma adjustment corrects for an over-reserved amount for bad debt amount that does not exist. Therefore, according to Mr. Dukes, Staff's proposed pro forma adjustment should be rejected by the Commission.

Q. What was the status of the Company's accounts receivable and allowance for doubtful accounts at the time of its filing?

A. At the time of its filing, the Company's Billed Accounts Receivable was $7,085,000 per their June 30, 2008 balance sheet. At that time, the allowance for doubtful accounts was $1,220,000 or over 17 percent of Billed Accounts Receivable. That amount had increased from $366,000 in 2005, which is an increase of over 300 percent.

Q. Does Mr. Dukes consider the allowance for doubtful accounts of 17 percent of billed accounts receivable to be reasonable?

A. Allowance for bad debts is the net difference of bad debt expense accruals and realized losses. Mr. Dukes suggests that he takes offense that Staff might question the appropriateness of the reserve for bad debt, but he believes it is perfectly reasonable to fail to recognize losses in a timely fashion. The accumulated reserve for bad debt is 200 percent of test year bad debts and certainly should not be considered reasonable.

Fleet Fuel Expense

Q. Do you propose a correction to Staff's fleet fuel expense?

A. Yes. The pro forma adjustment was calculated by subtracting test year gallons times current price per gallon from test year gallons times test year price to derive the adjustment of $294,599. However, an arithmetic error was made in multiplying test year gallons times current price. The incorrect amount was shown as $450,747, and it should have been $437,027. So the pro forma adjustment should have been $308,381 rather than $294,599 as shown on Schedule THF – C8.

Q. Is the correct pro forma fuel expense adjustment $308,381?

A. No. In providing the fleet fuel expense, the Company actually provided fleet fuel *cost*. Fleet cost, according to the Company, exceeds fuel expense because a portion of it is capitalized to capital projects. Because 26.6 percent of fuel cost is capitalized and assigned to capital projects associated with the fuel usage and the remainder is fuel expense, the fleet fuel expense adjustment should be reduced by 26.6 percent to $226,352.

Call Center

Q. Did the Company question Staff's pro forma adjustment for call center expense?

A. Yes. At pages 22 to 25, Mr. Dukes criticizes this adjustment. He suggests that call center usage was poorly measured and that if the Company had its own call center rather than sharing one with its sister companies that the cost would be higher.

Q. Do you agree with Mr. Dukes' argument?

A. No. Staff is not suggesting that the Company create its own call center. The issue really is not the allocation method, but that call center costs seem to be increasing at an alarming rate. The sizable increase in costs associated with the Call Center, and the apparent lack of justification for these cost increases, suggest that the Company may not be controlling costs as it should. Absent support for the increase in call center expenses, the Company should not be granted permission to recover those expenses. According to Mr. Erdwurm's Schedules with his Rebuttal Testimony, the Company's customer count has declined since the end of the previous test year.

Synchronized Interest

Q. Do you have a proposed correction to make for Staff's pro forma synchronized interest adjustment?

A. Yes. In its simultaneous equation work paper the Company makes an adjustment for synchronized interest. Therefore Staff's pro forma adjustment is not required.

Income Taxes

Q. Do you make an adjustment for income taxes?

A. Yes. Income taxes are recalculations made on the basis of other adjustments.

Q. Does that conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JUNE 08, 2009

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DAVID C. PARCELL RESUME ..... ATTACHMENT 1

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I. INTRODUCTION

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

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. Please summarize your educational background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings, dating back to 1972. In connection with this, I have previously filed testimony and/or testified in over 430 utility proceedings before about more than 40 regulatory agencies in the United States and Canada. Attachment 1 provides a more complete description of my education and relevant work experience.

Q. What is the purpose of your testimony in this proceeding?

A. I have been retained by the Utilities Division Staff to evaluate the cost of capital aspects of the current filing of UNS Gas, Inc. ("UNS Gas" or "Company"). I have performed independent studies and am making recommendations of the current cost of capital for UNS Gas. In addition, since UNS Gas is a subsidiary of UniSource Energy Corporation ("UniSource"), I have also evaluated UniSource in my analyses.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have prepared one exhibit, made up of 14 Schedules, identified as Schedule 1 through Schedule 14. These Schedules were prepared either by me or under my direction. The information contained in these schedules is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. What are your recommendations in this proceeding?

A. My overall cost of capital recommendations for UNS Gas are:

	Percent	Cost	Return
Long-Term Debt	50.01%	6.49%	3.25%
Common Equity	49.99%	9.5-10.5%	4.75-5.25%
Total	100.00%		7.99-8.49%
			8.24% mid-point

UNS Gas' application requests a return on common equity of 11.0 percent and overall rate of return of 8.75 percent. I propose a return on common equity of 10.0 percent and an overall rate of return of 8.24 percent.

Q. Please summarize your cost analyses and related conclusions for UNS Gas.

A. This proceeding is concerned with UNS Gas' regulated natural gas utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing an analysis of the Company's cost of capital is the development of the appropriate capital structure. UNS Gas' proposed capital structure is comprised of 49.99

percent common equity and 50.01 percent long-term debt. This capital structure is the June 30, 2008 test period capital structure of the Company. I also use this same capital structure in my cost of capital analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rate of debt. UNS Gas' application uses a cost rate of 6.49 percent, which reflects the Company's cost at June 30, 2008. I have used the same rate for this item as is proposed by the Company.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for UNS Gas. Each of these methodologies is applied to two groups of proxy utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9.5-10.5%
Capital Asset Pricing Model	7.3-7.8%
Comparable Earnings	9.5-10.5%

Based upon these findings, I conclude that the cost of common equity for UNS Gas is within a range of 9.5 percent to 10.5 percent. I recommend the mid-point of my cost of equity range (10.0 percent), which is the same cost of equity approved by the Commission in UNS Gas' last rate case. There is no indication that UNS Gas' level of risk has increased since the last proceeding. In addition, there are indications that capital costs have declined since the last case. Finally, the current economic recession should

have the effect of lowering the cost of equity. In any event, the impact of declining economic circumstances has negative effects on all of UNS Gas' customers (residential, commercial, and industrial) – there is no justification for increasing UNS Gas' profit level as the same time that virtually all of its customers has suffering from lower incomes/profits.

Combining these three steps into a weighted cost of capital results in an overall rate of return range of 7.99 percent to 8.49 percent. My recommended 10.0 percent cost of equity results in an overall cost of capital of 8.24 percent.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic and legal principles that establish the standards for determining a Fair Rate of Return for a regulated utility?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets used and useful (*i.e.*, rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the

balance sheet as a percentage. The revenue impact of the cost of capital is thus derived by multiplying the rate base by the rate of return (including income taxes).

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (*i.e.*, debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an *ex post* (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an *ex ante* (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably, as I have done in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two United States Supreme Court decisions provide the main standards for a fair rate of return. The first decision is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of fair and enlightened judgment**, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business undertakings** which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably sufficient to assure confidence in the **financial soundness** of the utility, and should be adequate, **under efficient and economical management**, to maintain and **support its credit** and **enable it to raise the money** necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. **[Emphasis added.]**

It is my understanding that the Bluefield decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the **investor** and **consumer interests** . . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity **owner** should be **commensurate** with **returns** on **investments** in **other enterprises having corresponding risks**. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the enterprise, so as to **maintain its credit** and to **attract capital**. **[Emphasis added.]**

The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the

fundamental premise, on which regulation rests, namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In Simms v. Round Valley Light & Power Company, 294 P.2d 378 (1956) the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

> "In the Hope case the court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return in computed might be arrived at."

My testimony does not advocate that the Commission ignore the Simms holding in this regard, or the fair value of UNS Gas' property, which it is required to consider under Article 15, Section of the Arizona Constitution. Rather, I find the Hope and Bluefield decisions can be helpful in their discussion of comparable earnings, financial integrity and capital attraction. I note that UNS Gas Witness Grant also cites the Hope and Bluefield cases as guidelines for evaluating the cost of capital for the Company.

Q. How can these parameters be employed to estimate the cost of capital for a utility?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), Comparable Earnings ("CE") and Risk Premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Q. Which methods have you employed in your analyses of the cost of common equity in this proceeding?

A. I have utilized three methodologies to determine UNS Gas' cost of common equity: the DCF, CAPM, and CE methods. I have not employed a RP model in my analyses although, as I indicate later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail in my testimony that follows.

IV. GENERAL ECONOMIC CONDITIONS

Q. Why are economic and financial conditions important in determining the costs of capital?

A. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and

financial conditions. At any given time, each of the following factors has an influence on the costs of capital: the level of economic activity (i.e., growth rate of the economy), the stage of the business cycle (i.e., recession, expansion, or transition), the level of inflation, and expected economic conditions. My understanding is that this position is consistent with the Bluefield decision that noted "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Q. What indicators of economic and financial activity have you evaluated in your analyses?

A. I have examined several sets of economic statistics from 1975 to the present. I chose this time period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to date, allowing for an assessment of changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences, and thus, permits a comparison of structural (or long-term) trends.

Q. Please describe the timeframe of the three prior business cycles and the most recent cycle.

A. The three prior complete cycles and most recent cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
Current	Dec. 2001-Nov. 2007	Dec. 2007-Present

Source: National Bureau of Economic, Research, "Business Cycle Expansions and Contractions."

Q. Do you have any general observations concerning the recent trends in economic conditions and their impact on capital costs over this broad period?

A. Yes, I do. As I will describe below, until recently the U.S. economy enjoyed general prosperity and stability over the period since the early 1980s. This period has been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs. The current business cycle began in late 2001, following a somewhat modest recession earlier in the year.

Over the past two years, on the other hand, the economy has declined significantly, initially as a result of the 2007 collapse of the "sub-prime" mortgage market and related liquidity crises in the financial sector of the economy. Subsequently, this financial crisis intensified with a more broad-based decline initially based on a significant increase in petroleum prices and an increasing decline in the U.S. financial sector culminating with

the collapse and/or bailouts of a substantial number of long-standing institutions such as Bear Stearns, Lehman Brothers, Merrill Lynch, Freddie Mac, Fannie Mae, AIG and Wachovia. This crisis has been described as the worst financial crisis since the Great Depression. The U.S. and global governments are in the process of implementing unprecedented actions to attempt to correct or minimize its scope and effects. As of this time, the consequences of these governmental initiatives are unclear. There is also a universal acceptance that the economy is in a serious recession. The impacts of a severe recession on cost of capital is very likely to be characterized by lower utility growth and declining capital costs due to a decline in corporate profits and expected earnings growth. It is clear that a serious recession also has negative impacts on UNS Gas' customers, in terms of income levels, unemployment and higher poverty levels. In addition, it is likely that UNS Gas' business customers are experiencing lower profits as a result of the recession. Clearly, this is not an environment in which it is sensible to increase the profitability of a regulated company such as UNS Gas.

Q. Please describe recent and current economic and financial conditions and their impact on the costs of capital.

A. Schedule 2 shows several sets of economic data. Pages 1 and 2 contain general macroeconomic statistics while pages 4 through 6 contain financial market statistics. Pages 1 and 2 show that the U.S. economy ended 2007 as the sixth year of an economic expansion although, as indicated previously, the economy was then entering a decline. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product ("GDP"), industrial production, and the increase in the unemployment rate. This most recent expansion was characterized by slower growth, in comparison to prior expansions which resulted in lower inflationary pressures and interest rates.

The rate of inflation is also shown on pages 1 and 2. As is reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 4.1 percent or lower. The 0.1 percent rate of inflation in 2008 was the lowest level of the past thirty years. This is indicative of virtually no inflation, which should also be reflective of lower capital costs.

Q. What have been the trends in interest rates?

A. Pages 3 and 4 show several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates declined substantially in conjunction with inflation rates throughout the remainder of the 1980s and throughout the 1990s. Interest rates declined even further from 2000-2005 and generally recorded their lowest levels since the 1960s.

During the past several years and up until the later half of 2008, long-term interest rates remained low by historic standards. During the 2001 recession and early in the succeeding expansion, the Federal Reserve lowered interest rates (i.e., Federal Funds rate) 11 times in 2001 and twice in 2003 in an effort to stimulate the economy. Following this, the Federal Reserve increased short-term interest rates on 17 occasions between 2004 and 2006,[1] although each time by only 0.25 percent, in an attempt to ensure that any perceived inflationary expectations will not stifle continued economic growth. Nevertheless, the Federal Reserve actions did not result in a pronounced increase in long-term rates. Most recently, however, the Federal Reserve has lowered the

[1] See Federal Reserve Bank of New York, "Historical Changes of the Target Federal Funds and Discount Rates," www.newyorkfed.org/markets/statistics/dlyrates/fedrate.html.

Federal Funds rate (i.e., short-term rate) on several occasions and it is currently 0.25 percent, an all-time low. The year 2008 experienced a pronounced decline in short-term rates and long-term U.S. Treasury Securities yields, and an increase in utility bond yields.

Q. What have been the trends in common share prices?

A. Pages 5 and 6 show several series of common stock prices and ratios. These ratios indicate that share prices were essentially stagnant during the high inflation/interest rate environment of the late 1970s and early 1980s. On the other hand, the 1983-1991 business cycle and the most recent cycles witnessed a significant upward trend in stock prices. Since the beginning of the current financial crisis, on the other hand, stock prices have declined precipitously and have been very volatile. Stock prices in 2008 and early 2009 are down significantly from 2007 levels, reflecting the financial/economic crises.

Q. What conclusions do you draw from your discussion of economic and financial conditions?

A. It is apparent that recent and current economic/financial circumstances are radically different from any that have prevailed since at least the 1930s. The recent deterioration in stock prices and the decline in U.S. Treasury bond yields and increase in corporate bond yields reflect the "flight to safety" that describes the extreme reluctance of investors to purchase common stocks and corporate bonds while moving investments into the very safe government bonds.

This "flight to safety" should not be interpreted to reflect an increase in the cost of capital, however. Rather, it more properly reflects an "availability of capital" since investors have been recently been unwilling to invest in any assets other than U.S.

Treasury bonds. As I noted previously, the opportunity cost of capital, as measured by the recent and current returns of unregulated firms, has been the lowest in recent memory. Clearly, this cannot be claimed to reflect an increase in the cost of capital for a regulated firm such as UNS Gas.

V. UNS GAS' OPERATIONS AND RISKS

Q. PLEASE SUMMARIZE UNS GAS AND ITS OPERATIONS.

A. UNS Gas is a public utility that provides natural gas distribution services to some 146,000 customers in Arizona. UNS Gas was formerly the Arizona natural gas distribution operations of Citizens Communications Company, prior to its 2003 acquisition by UniSource Energy. When UniSource Energy acquired the Arizona electric and gas assets from Citizens, it formed two operating companies - UNS Electric and UNS Gas.

Q. PLEASE DESCRIBE UNISOURCE ENERGY.

A. UniSource Energy is a holding company, whose principal subsidiary is Tucson Electric Power Company ("TEP"), a generation and distribution company that is the second-largest investor-owned utility in Arizona. UniSource Energy also owns UniSource Energy Services ("UES"), which contains UNS Electric and UNS Gas, both of which are distribution companies. It previously owned Millennium Energy Holdings, the parent company of UniSource Energy's unregulated energy business whose principal subsidiary was Global Solar. UniSource Energy presently operates through three primary business segments – TEP, UNS Electric and UNS Gas.

Q. WHAT HAVE BEEN THE BUSINESS SEGMENT RATIOS OF UNISOURCE ENERGY IN RECENT YEARS?

A. This is shown on Schedule 3. As this indicates, as of 2008, UNS Gas accounted for about 12 percent of the revenues of UniSource Energy and about 8 percent of total assets.

Q. WHAT ARE THE CURRENT BOND RATINGS OF UNISOURCE ENERGY, UNS GAS AND TEP?

A. The current ratings of UniSource Energy, UNS Gas and TEP are:

	Standard & Poor's	Moody's	Fitch
UniSource Energy Credit Ratings			
Senior Secured Debt	NR	Ba1	NR
Issuer Rating	NR	Ba1	N/A
UNS Gas Credit Ratings			
Senior Unsecured Debt		Baa3	
Tucson Electric Power Credit Ratings			
Senior Secured Debt	BBB	Baa2	BBB-
Senior Unsecured Debt	BBB-	Baa3	BB+
Issuer Rating	BB	Baa3	BB

Source: UniSource Energy Web Site.

UNS Gas now has its own security ratings by Moody's but not S&P and Fitch. The debt of UNS Gas is guaranteed by UES. As such, the debt of UNS Gas is related to the overall credit strength of UniSource Energy.

Q. Did the acquisition of the assets current comprising UNS Gas have any impact on the security ratings of UniSource Energy or TEP?

A. No, it did not. Standard & Poor's, for example, made the following comments in an August 12, 2003 CreditWatch report on TEP:

> Standard & Poor's Ratings Services said today it affirmed its ratings on Tucson Electric Power Co. ('BB' corporate credit rating) and removed them from CreditWatch with negative implications. They were placed on CreditWatch Nov. 8, 2002, reflecting parent UniSource Energy Corp.'s announcement of an agreement to **purchase** the **Arizona electric** and **gas transmission and distribution assets** from Citizens Communications Co. The outlook is stable.
>
> The Aug. 11, 2003, acquisition of **these relatively low-risk, widely scattered regulated assets** for $220 million, **well below the book value** of about $425 million, **bolsters the consolidated business profile** of the UniSource Energy family of companies, and does so with a financing package that **marginally improves the overall financial condition of UniSource Energy**. These assets are subject to regulation by the Arizona Corporation Commission (ACC), as is Tucson Electric, and are structured as a wholly owned subsidiary of UniSource Energy called UniSource Energy Services.

The addition of about 77,000 electric customers and 126,000 gas customers represents an increase of about 40% to Tucson Electric's customer base. The acquisition has received strong regulatory support, mainly because rate increases will be limited to only about one-half of what they would have been in the absence of the purchase, as well as because of operational challenges faced by prior management. **[Emphasis added]**

Q. What have been the recent descriptions of UNS Gas by rating agencies?

A. In October of 2008, Moody's assigned a rating of Baa3 to UNS Gas. In its report, Moody's stated:

Recent Developments

On October 28, 2006, Moody's assigned a Baa3 rating to approximately $100 million of senior unsecured guaranteed notes (the Notes) of UNS Gas, Inc. and assigned a stable outlook. The Notes are guaranteed by UES.

In July and August 2008, Moody's assigned ratings of Baa3 to UNS Gas and UNS Electric's joint $80 million guaranteed credit facility, and to UNS Electric's $100 million senior unsecured guaranteed notes. The facility and the UNS Electric notes are also guaranteed by UES.

Rating Rationale

The Baa3 rating assigned to UNS Gas' senior unsecured notes reflects the interdependence that currently exists between the company and its affiliate UNS Electric as a result of their shared credit facility and parental guarantee from UES. The rating reflects our view of the consolidated credit quality of UES, which guarantees the debt of both UNS Gas and UNS Electric. The UNS Gas/UNS Electric shared senior unsecured revolving credit facility, and the guaranteed senior unsecured notes of UNS Electric, are also rated Baa3. For additional information, please see July 8, 2008 press release and related July 9, 2008 credit opinion for UNS Gas/UNS Electric.

On a stand-alone basis, following the framework outlined in Moody's Rating Methodology for the North American Regulated Gas Distribution Industry (Local Gas Distribution Companies), (the LDC Methodology), **UNS Gas' credit profile maps to a Baa2**. The Methodology focuses on core factors including degree of profitability, the level of regulatory support, degree of ring fencing, and financial strength and flexibility as evidenced by key financial metrics and liquidity. **[Emphasis added]**

This quote by S&P indicates that the ratings of UNS Gas are:

Tied to UNS Electric;

Based on consolidated credit profile of UES; and,

Lower than they would be if UNS Gas own credit profile was used to establish its ratings.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (*i.e.*, the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates

associated income tax liabilities; and, (3) causes the most controversy since its cost cannot be precisely determined.

Q. How have you evaluated the capital structure of UNS Gas?

A. I have first examined the historic (2004-2008) capital structure ratios of UNS Gas. These are shown on Page 1 of Schedule 4. I have summarized below the common equity ratios for UNS Gas:

	Including S-T Debt	Excluding S-T Debt
2004	37.0%	37.0%
2005	44.4%	44.4%
2006	45.7%	45.7%
2007	46.9%	46.9%
2008	49.2%	49.2%

Page 2 of Schedule 4 shows the historic capital structure ratios of UniSource on a consolidated basis. This indicates the following common equity ratios:

	Including S-T Debt	Excluding S-T Debt
2004	31.6%	31.6%
2005	33.6%	33.7%
2006	34.9%	35.8%
2007	40.7%	41.0%
2008	33.9%	34.1%

These common equity ratios are somewhat lower than those of UNS Gas.

Q. How do these capital structures compare to those of investor-owned electric utilities?

A. Schedule 5 shows the common equity ratios (including short-term debt in capitalization) for the two groups of proxy utilities utilized in my cost of equity analyses. These are:

Year	Proxy Group	Grant Group
2004	41.5%	52.5%
2005	43.6%	52.4%
2006	45.1%	53.3%
2007	48.0%	54.9%
2008	47.3%	56.0%

These common equity ratios for the proxy group are lower than those of UNS Gas while those of the Grant Group are higher.

Q. What capital structure ratios has UNS Gas requested in this proceeding?

A. The Company requests use of the following capital structure:

Long-Term Debt	50.01%
Common Equity	49.99%

According to Schedule D-1 of UNS Gas' filing, this is the proforma or adjusted test year capital structure of the Company at June 30, 2008.

Q. What capital structure do you propose to use in this proceeding?

A. I use the capital structure ratios as proposed by UNS Gas.

Q. What is the cost rate of debt in the company's application?

A. The Company's filing cites a cost of long-term debt of 6.49 percent. This is represented to be the Company's actual cost at June 30, 2008. I also use this cost of long-term debt in my cost of capital analyses.

Q. Can the cost of common equity be determined with the same degree of precision as the costs of debt?

A. No. The cost rates of debt are largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. There are, however, several models which can be employed to estimate the cost of common equity. Three of the primary methods – DCF, CAPM, and CE – are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUPS

Q. How have you estimated the cost of common equity for UNS Gas?

A. UNS Gas is not a publicly-traded company. UniSource, UNS Gas' parent company, is a publicly-traded company. Consequently, it is possible to directly apply cost of equity models to UniSource. However, it is generally desirable to analyze groups of comparison

or "proxy" companies as a substitute for UNS Gas to determine its cost of common equity.

I have examined two such groups for comparison to UNs Gas and UniSource. I have first selected one group of electric utilities similar to UNS Gas and UniSource using the criteria listed on Schedule 6.

Second, I have conducted studies of the cost of equity for the proxy group of natural gas utilities selected by UNS Gas' witness Kentton Grant.

VIII. DISCOUNTED CASH FLOW ANALYSIS

Q. What is the theory and methodological basis of the discounted cash flow ("DCF") model?

A. The DCF model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where:

K = discount rate (cost of capital)

P = current price

D = current dividend rate

g = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how you have employed the DCF model.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; *i.e.*, current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is the version listed below:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (February-April, 2009). The D_0 is the current annualized dividend rate for each proxy company.

Q. How have you estimated the dividend growth component of the DCF equation?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock. Obviously, since two investors reach different decisions at the same market price, their expectations differ.

A wide array of indicators exists for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2004-2008 (5-year average) earnings retention, or fundamental growth (per Value Line);
2. 5-year average of historic growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS") (per Value Line);
3. 2009, 2010, and 2012-2014 projections of earnings retention growth (per Value Line);
4. 2006-2008 to 2012-2014 projections of EPS, DPS, and BVPS (per Value Line); and
5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. Please describe your initial DCF calculations.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the "raw" DCF

calculations, which are presented on several bases: mean, median, and low/high values. These results can be summarized as follows:

			Mean		Median	
	Mean	Median	Low	High	Low	High
Proxy Group	10.5%	9.9%	9.0%	11.9%	9.8%	11.9%
Grant Group	9.6%	9.5%	8.8%	10.3%	8.3%	9.5%

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected cost of capital for the proxy group; rather, the individual values shown should be interpreted as alternative information considered by investors. The individual DCF calculations also demonstrate how the focus on a single growth rate, such as EPS projections, can produce a DCF conclusion that is not reflective of a broader perspective of available information.

The results in Schedule 7 indicate average (mean and median) DCF cost rates of 9.5 percent to 10.5 percent. The range of DCF rates (i.e., using the lowest and highest growth rates only) are 8.8 percent 11.9 percent.

Q. What do you conclude from your DCF analysis?

A. This analysis reflects a DCF range of about 9.5 percent to about 10.5 percent for the proxy group. This is approximated by the average/mean values for the proxy groups examined in the previous analysis. I give less weight to the extreme lower and upper ends of the groups, which are impacted by outlier results. I believe that 9.5 percent to 10.5 percent reflects the proper DCF cost for UNS Gas.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. Please describe the theory and methodological basis of the capital asset pricing model ("CAPM").

A. The CAPM is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory ("MPT"), which studies the relationships among risk, diversification, and expected returns.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where:

K = cost of equity

Rf = risk free rate

Rm = return on market

β = beta

Rm-Rf = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (*i.e.*, beta), whereas the simple risk premium method assumes the same risk premium for all companies exhibiting similar bond ratings.

Q. What groups of companies have you utilized to perform your CAPM analyses?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. Please explain the risk-free rate as used in your CAPM and indicate what rate you employed.

A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three-month average yield (February-April, 2009) for 20-year U.S. Treasury bonds. Over this three-month period, these bonds had an average yield of 3.82 percent.

Q. What is beta and what betas did you employ in your CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1.0 are considered less risky than the market, whereas betas greater than 1.0 are more risky. Utility stocks traditionally have had betas below 1.0. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. How did you estimate the market risk premium component in your CAPM analysis?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the return on equity for the S&P 500 group for the period 1978-2007 (all available years reported by S&P). This schedule also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (*i.e.*, risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.45 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term government bonds, as tabulated by Morningstar (formerly Ibbotson Associates), using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2008 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	11.7%	6.1%	5.6%
Geometric	9.6%	5.7%	3.9%

I conclude from this that the expected risk premium is about 5.32 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 9 shows my CAPM calculations using the risk premium. The results are:

	Mean	Median
Proxy Group	7.7%	7.5%
Grant Group	7.4%	7.3%

Q. What is your conclusion concerning the CAPM cost of equity?

A. The CAPM results collectively indicate a cost of 7.3 percent to 7.7 percent for the groups of comparison utilities. I conclude that the CAPM cost of equity for UNS Gas is 7.3 percent to 7.5 percent.

X. COMPARABLE EARNINGS ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure

of the fair return, because the CE method translates into practice the competitive principle upon which regulation is based.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. How have you employed the CE methodology in your analysis of UNS Gas' common equity cost?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (*i.e.,* 100%) reflect a situation where a company is able to attract new equity capital without dilution (*i.e.*, above book value). As a result, one objective of a fair cost of equity is the maintenance of stock prices above book value.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my analysis is not subject to the criticisms occasionally made by some who

maintain that past earned returns do not represent the cost of capital. In addition, my analysis uses prospective returns and thus is not confined to historical data.

Q. What time periods have you examined in your CE analysis?

A. My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2008 (*i.e.,* the last seventeen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2002-2008 (the current business cycle) and 1992-2001 (the most recent complete business cycle).

Q. PLEASE DESCRIBE YOUR CE ANALYSIS.

A. Schedules 10 and 11 contain summaries of experienced returns on equity for several groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the groups of proxy utilities. These can be summarized as follows:

	Proxy Group	Grant Group
Historic ROE		
Mean	8.3-10.0%	11.8-11.9%
Median	8.3-11.1%	11.9-12.1%
Historic M/B		
Mean	133-152%	179-183%
Median	124-144%	180-183%
Prospective ROE		
Mean	8.4-9.2%	11.4-11.7%
Median	8.6-8.5%	11.0-12.3%

These results indicate that historic returns of 8.3 percent to 12.1 percent have been adequate to produce market-to-book ratios of 124 percent to 183 percent for the groups of proxy utilities, with the higher returns being accompanied by the higher market-to-book ratios. Furthermore, projected returns on equity for 2009, 2010, and 2012-2014 are within a range of 8.0 percent to 12.3 percent for the utility groups. These relate to 2008 market-to-book ratios of 127 percent or higher again with the higher returns accompanying the higher market-to-book ratios.

Q. Have you also reviewed earnings of unregulated firms?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well-recognized group of firms that is widely utilized in the investment community and is indicative of the

competitive sector of the economy. Schedule 11 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past sixteen years. As this Schedule indicates, over the two periods this group's average earned returns ranged from 13.9 percent to 14.7 percent with market-to-book ratios ranging between 284 percent and 341 percent.

Q. How can the above information be used to estimate the cost of equity for UNS Gas?

A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for proxy utilities, however, it is necessary to compare the risk levels of the utility industry with those of the competitive sector. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is more risky than the utility proxy groups.

Q. What return on equity is indicated by the CE analysis?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 9.5 percent to 10.5 percent. Recent returns of 8.3 percent to 12.1 percent have resulted in market-to-book ratios of 124 and greater. Prospective returns of 8.0 percent to 12.3 percent result in anticipated market-to-book ratios of over 125 percent, again with the higher returns being associated with much higher market-to-book ratios. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 9.5 percent to 10.5 percent should thus result in a market-to-book ratio of over 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially

exceed 100 percent indicates that historic and prospective returns of over 10 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

Please also note that my CE analysis is not based on a mathematic formula approach, as are the DCF and CAPM methodologies. Rather, it is based on recent trends and current conditions in equity markets. Further, it is based on the direct relationship between returns on common stock and market-to-book ratios of common stock. In utility rate setting, a fair rate of return is based on the utility's assets (*i.e.*, rate base) and the book value of the utility's capital structure. As stated earlier, maintenance of a financially stable utility's market-to-book ratio at 100 percent, or a bit higher, is fully adequate to maintain the utility's financial stability. On the other hand, a market price of a utility's common stock that is 150 percent or more above the stock's book value is indicative of earnings that exceed the utility's reasonable cost of capital. Thus, actual or projected earnings do not directly translate into a utility's reasonable cost of equity. Rather, they must be viewed in relation to the market-to-book ratios of the utility's common stock.

My 9.5 percent to 10.5 percent CE recommendation is not designed to result in market-to-book ratios as low as 1.0 for UNS Gas. Rather, it is based on current market conditions and the proposition that ratepayers should not be required to pay rates based on earnings levels that result in excessive market-to-book ratios.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three cost of equity analyses.

A. My three methodologies produce the following:

Discounted Cash Flow	9.5-10.5%
Capital Asset Pricing Model	7.3-7.7%
Comparable Earnings	9.5-10.5%

Q. What is your cost of equity recommendation for UNS Gas?

A. I recommend a cost of equity of 9.5 percent to 10.5 percent for UNS Gas. This reflects two of my three cost of equity model results. Within this range, I recommend a 10.0 percent level, the same return on equity approved for UNS Gas in the Company's last rate proceeding.

Q. Please explain how the recent and current economic and financial crisis impacts the cost of equity for UNS Gas.

A. It is well chronicled that, over the past two years and especially over the past several months, the United States and global financial markets have been in turmoil. The impacts of this have been far-reaching and extreme, with global credit markets virtually coming to a standstill. This crisis and its impact, however, do not imply that the cost of equity for gas utilities such as UNS Gas have increased. I say this for the following reasons.

First, it must be emphasized that depressed economic conditions and the financial crisis affects virtually all sectors of the economy – households, small businesses, larger

commercial and industrials – and, in most cases, the impact is greater than is the case for UNS Gas. UNS Gas is a regulated utility that sells a product that has no real substitutes and is a product that consumers can do little to control the amount they use. As such, UNS Gas and utilities are partially, if not largely, insulated from the impacts of depressed economic conditions.

Second, the major impact of a recession will be to depress the profits of most enterprises. As a result, it is to be expected that capital costs will decrease in tandem with a significant recession. There is no justification for increasing the profit level of a regulated utility such as UNS Gas at the same time that other enterprises are experiencing lower profits.

Third, even if UNS Gas were to incur higher costs of debt and/or other capital costs, these costs can be passed along to ratepayers at the next rate proceeding. Unregulated firms cannot do this.

Fourth, there is no indication that UNS Gas' risks have increased since its last rate proceeding. Absent a demonstration that UNS Gas' risks have increased, there is no justification for increasing its cost of equity.

Fifth, the United States and global governments have and are taking extraordinary measures to avoid a further worsening of the current market turmoil. Most of these measures are designed to put liquidity into the credit markets and make credit more accessible again and, in the process, restore more confidence to the financial markets. All of these measures are clearly designed to lower the cost of capital. In this

environment, it would be counter-productive to make any claim that UNS Gas should have a higher return at this time due to the above-cited market turmoil.

XII. TOTAL COST OF CAPITAL

Q. What is the total cost of capital for UNS Gas?

A. Schedule 1 reflects the total cost of capital for the Company using UNS Gas' proposed capital structure and cost of debt along with the range of common equity costs my analyses support. The resulting total cost of capital is a range of 7.99 percent to 8.49 percent. I recommend that a 8.24 percent total cost of capital be established for UNS Gas.

Q. Does your cost of capital recommendation provide the company with a sufficient level of earnings to maintain its financial integrity?

A. Yes, it does. Schedule 14 shows the pre-tax coverage that would result if UNS Gas earned my cost of capital recommendation. As the results indicate, my recommended range would produce a coverage level above the benchmark range for a BBB rated utility. In addition, the debt ratio (which reflects the Company's proposed capital structure) is within the benchmark for a BBB rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. Have you reviewed the testimony and cost of capital recommendation of UNS Gas witness Kentton C. Grant?

A. Yes, I have. Mr. Grant is recommending the following cost of capital for UNS Gas.

Capital Item	Percent	Cost	Weighted Cost
Long-term Debt	50.01%	6.49%	3.25%
Common Equity	49.99%	11.00%	5.50%
Total	100.0%		8.75%

Mr. Grant's 11.0 percent cost of common equity recommendation is derived as follows:

	Range	Average
DCF	9.5-11.2%%	10.1%
CAPM	10.2-11.3%	10.7%
Risk Premium	10.2-11.5%	

Q. Do you have any comments concerning Mr. Grant's DCF analysis and recommendations?

A. I note that Mr. Grant's 10.1 percent DCF conclusion is based upon his application of a DCF model to a group of 10 gas distribution utilities. This 10.1 percent average is nearly identical to my 10.0 percent DCF mid-point.

Q. What are you comments concerning Mr. Grant's CAPM analysis and conclusions?

A. Mr. Grant's CAPM analysis takes the following form:

Risk-free rate =	4.53%	=	August 2007 20-yr. T bonds Yield
Risk Premium =	7.1%	=	MorningStar risk premium
Beta =		=	Value Line

My primary disagreement is with Mr. Grant's risk premium input. My disagreements with Mr. Grant's risk premium are his exclusive reliance on the 1926-2007 arithmetic average differences between large company stocks (i.e., S&P 500) and long-term Treasury bonds. As I indicated earlier in my testimony, it is preferable to use multiple sources of risk premium measures, as I have done. Mr. Grant's 7.1 percent risk premium used only arithmetic returns, and ignores geometric (compound) returns in deriving the risk premium component of the CAPM. This is not proper. It is apparent that investors have access to both types of returns, and correspondingly use both types of returns, which they make investment decisions.

In fact, it is noteworthy that mutual fund investors regularly receive reports on their own funds, as well as prospective funds they are considering investing in, that show only geometric returns. Based on this, I find it difficult to accept Mr. Grant's position that only arithmetic returns are considered by investors, and, thus, only arithmetic returns are appropriate in a CAPM context.

I also disagree with Mr. Grant's 7.1 percent risk premium since it improperly used "income returns" from the Morningstar study rather than "total returns." What Mr. Grant did was compare the differential between total returns for common stocks (i.e., dividends and capital gains) and only income returns for Treasury bonds. As such, he has ignored the capital gains component of the Treasury bonds return. As I indicated in my earlier testimony, the differential between total returns of common stocks and Treasury bonds, is 5.6 percent on an arithmetic basis. In addition, Mr. Grant's use of the Morningstar study only used half of the reported data (arithmetic means) and ignored the other half of the reported data (geometric means).

It is apparent that, when Mr. Grant's historic risk premium estimate is updated for the inclusion of 2008 data, a much different picture emerges. The 1926-2008 differential between the arithmetic returns of the S&P 500 and long-term government bonds has declined from 6.5 percent to 5.6 percent (i.e., 11.7 percent total return for S&P 500 minus 6.1 percent total return for long-term government bonds), a reduction of 90 basis points. A similar update of his "income return" would have the effect of reducing his CAPM risk premium to 6.5 percent, or 60 basis points.

Q. What are your comments about Mr. Grant's equity risk premium method and results?

A. Mr. Grant's equity risk premium method looks at the relationship between state regulatory commission return on equity awards and corresponding public utility bond yields over the period 2003 – mid 2008. On page 23 and KCG-11, he concludes that a range of 3.75 percent to 5.0 percent reflects the appropriate spread between the cost of equity and utility bond yields, reflecting the average value of the spread (i.e., 4.375 percent) plus or minus one standard deviation. I do not believe that the upper portion of Mr. Grant's 3.75 percent to 5.5 percent equity risk premium range is appropriate. Consider, for example, the average awarded returns on equity and triple-B bond yields over the past few years:

Year	Auth. ROE	Baa Yields	Spread
2005	10.54%	5.93%	4.61%
2006	10.36%	6.32%	4.04%
2007	10.36%	6.33%	4.03%
2008	10.46%	7.25%	3.21%
Average			3.97%

This indicates an average equity risk premium of about 4 percent over this period. Combining this 4 percent equity risk premium with Mr. Grant's estimate of 6.48 percent for public utility bonds in August results in a cost of equity of about 10.5 percent, the top end of my recommended range.

Q. Mr. Grant also makes an adjustment for the size of UNS Gas, is this proper?

A. No, it is not. UNS Gas does not raise its own equity capital (as it comes from UniSource Energy) and its debt is guaranteed by UES. As a result, it is these entities that are evaluated by investors and it is the size of these entities that investors consider.

XIV. FAIR VALUE RATE BASE ("FVRB") COST OF CAPITAL

Q. What is your understanding of UNS Gas's position on the issue of fair value rate base and related cost of capital implications?

A. It is my understanding that UNS Gas is requesting that a 6.80 percent cost of capital be applied to the level of its FVRB.

Q. What is your understanding of the commission's procedure for utilizing the fair value of rate base in setting utility rates?

A. My "non-legal understanding" is that the Commission must consider the fair value of a utility's assets in setting rates. However, I do not agree that this implies that the Company's cost of capital must be applied to the fair value of the rate base.

Q. Are you aware that the Commission has recently conducted a "remand" hearing on the issue of regulatory treatment of FVRB for Chaparral City Water Company?

A. Yes, I am. In January of 2008, the Commission conducted a public hearing in response to a remand by the Arizona Court of Appeals (No. CA-CC 05-002)[2] in Chaparral City Water Company (Docket No. W-02113A-04-0616). The purpose of this hearing was to determine the appropriate cost of capital to be applied to an Arizona utility's fair value rate base. The Commission's Decision No. 70441 in this proceeding established a Fair Value Rate of Return ("FVROR") by subtracting the inflation rate from the cost of equity.

Q. What is your understanding of the use of FVRB in Arizona?

A. My "non-legal understanding" is based in part on the 2006 Arizona Court of Appeals in the Chaparral City case that indicates that the Court agreed with the Commission that "the cost of capital analysis 'is geared to concepts of original cost measures of rate base, not fair value measures of rate base . . . ." The decision goes on to make the following statement: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology." It is correspondingly the purpose of this section of my testimony to recommend an "appropriate methodology" for use in conjunction with a FVRB.

[2] CA-CC 05-0002, Memorandum Decision dated February 13, 2007.

Q. Do you have any observations based upon your own experience in cost of capital determination, as to whether a cost of capital developed for application to an original cost rate base is consistent with a FVRB?

A. Yes, I do. It is my personal experience, based upon over 35 years of providing cost of capital testimony, that the concept of cost of capital is designed to apply to an original cost rate base. This is the case since the cost of capital is derived from the liabilities/owners' equity side of a utility's balance sheet using the book values of the capital structure components. The cost of capital, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet (i.e., OCRB). From a financial perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the cost of capital is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of fair value rate base is incorporated, however, this link between rate base and capital structure is broken. The amount of fair value rate base that exceeds original cost rate base is not financed with investor-supplied funds and, indeed, is not financed at all. As a result, a customary cost of capital analysis cannot be automatically applied to the fair value rate base since there is no financial link between the two concepts. In my "non-legal" opinion, both the Commission and Appeals Court have also recognized this lack of compatibility between a customary weighted cost of capital ("WCOC") analysis and FVRB.

Q. Why is it important that there be a link between the concepts of rate base and cost of capital?

A. This link is important since financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world), the link between cost of capital and rate base satisfies this financial objective.

Q. Based on your experience as a cost of capital witness over the past 35 years, do you have a suggestion as to how to account for the use of a FVRB in setting rates for UNS Gas?

A. Yes, I do. Since the increment between fair value rate base and original cost rate base is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the increment of FVRB over the OCRB. Such a procedure would still provide for a return being earned on all investor-supplied funds and would thus be consistent with financial standards.

Q. Have you made such a proposal in this proceeding?

A. Yes, I have. As is shown below, I have developed a capital structure and FVROR that applies to UNS Gas' FVRB.

Item	Amount (000)	Percent	Cost	Fair Value Return
Long-term Debt	$99,265	36.56%	6.49%	2.37%
Common Equity	99,242	36.55%	10.00%	3.66%
FVRB Increment[3]	73,015	26.89%	0.00%	0.00%
Total FVRB Capital	$271,522	100.00%		6.03%

Applying this 6.03 percent to the FVRB provides for a return on all investor-supplied capital and is therefore an appropriate rate to apply to the FVRB from a financial and economic standpoint. As such, it provides for an appropriate fair value rate of return to be applied to a FVRB.

Q. Have you developed an alternative method with which to apply a FVROR to a FVRB?

A. Yes, I have. Should the Commission determine that there should be a specific return (greater than zero) applied to the FVRB Increment, I have provided such a procedure.

Q. Why is it necessary to add a return on only the portion of FVRB that exceeds the OCRB?

A. The WCOC authorized by the Commission has already provided for a full cost of equity return and cost of debt on the portions of equity and debt capital that are supporting the

[3] FVRB minus OCRB.

OCRB portion of the FVRB. As a result, there is no need to provide any additional return on the portions of FVRB supported by common equity and debt.

Stated differently, both the cost of debt and the return on common equity (i.e., capital stock, paid-in capital, and retained earnings - the investment of common shareholders) are already provided for in a traditional WCOC. Only the portion of the FVRB that exceeds OCRB ("Fair Value Increment") needs to have a specific return identified in order to reflect a return component on that Fair Value Increment.

Q. What is the proper cost rate to apply to the fair value increment?

A. As I indicated previously, from a financial perspective, it should not be necessary to provide for any return on the Fair Value Increment since this is not investor-supplied capital. However, the Commission may choose to evaluate this issue from both a financial and a public policy perspective. I am aware that UNS Gas may claim that the concept of fair value carries with it the notion that investors should receive some benefit when fair value is greater than original cost and should suffer some detriment when fair value is less than original cost. It is possible that the Commission may determine that Arizona's fair value provision, which is somewhat unique, is not inconsistent with these concepts. Nonetheless, the idea that the Company should receive some benefit from the Fair Value Increment does not mean that one should automatically apply to the FVRB a WCOC developed by reference to original cost rate base. If it is determined that it is desirable to provide an additional (non-zero) return on the Fair Value Increment, the proper return should be no larger than the real (i.e., after inflation is removed) risk-free rate of return.

Q. What is the risk-free return?

A. The risk-free return is, in financial terms, the return on an investment that carries little or no risk. Risk-free investments are universally defined as U.S. Treasury Securities, with short-term maturities usually being used as the risk-free rate. Over the past several months, various maturities of U.S. Treasury securities have yielded from about 0.05 percent (short-term) to 4.0 percent (long-term) in nominal terms. I also note that 2009-2010 forecasts of U.S. Treasury securities are about 1.0 percent to 4.5 percent. As a result, I use 4.5 percent as the nominal risk-free rate.

Q. What is the "real" risk-free rate?

A. The concept of real rates involves the removal of the rate of inflation from the nominal risk-free rate. In 2008, the rate of inflation, as measured by the Consumer Price Index ("CPI"), was 0.1 percent. Forecasts of the CPI for 2009-2010 are about 1.5 percent to 2.2 percent. As a result, I propose to use a 2.0 percent inflation rate for computing the real risk-free rate, which is computed as follows:

Nominal Risk-Free Rate	4.5%
Less: Inflation Rate	2.0%
Equals: Real Risk-Free Rate	2.5%

Q. Please explain why UNS Gas' FVROR should consider the real risk-free rate, as opposed to the nominal risk-free rate.

A. The investors of UNS Gas are already receiving an inflation factor due to the inclusion of inflation in the FVRB Increment. Specifically, the Fair Value Increment incorporates inflation by considering the current value of assets, which reflect, in part, past inflation.

It would be double-counting to also include the inflation components in the return to be applied to the FVRB Increment.

Q. What return on the Fair Value Increment do you recommend in your alternative FVROR proposal?

A. My alternative FVROR proposal incorporates a return on the Fair Value Increment with a maximum value of 2.5 percent, as developed above. However, I wish to emphasize that this 2.5 percent value is the maximum value that could be applied to the FVRB Increment. In reality, any value between zero percent and 2.5 percent could be used as the cost rate on the FVRB Increment. As I stated above, this Fair Value Increment return is in addition to the return that the Company's investors already earn on their investment in the Company. In this sense, an above-zero cost rate for the fair value increment represents a bonus to the Company that would have to find its justification in policy considerations instead of in pure economic or financial principles; for that reason, the selection of an appropriate cost rate within this range should fall to the Commission's discretion. I would propose the mid-point of this range, or 1.25 percent.

Q. What is the resulting impact of your alternative proposal in this proceeding?

A. I am proposing the following modified FVROR for UNS Gas:

Capital Item	Percent	Cost	Return
Long-term Debt	36.56%	6.49%	2.37%
Common Equity	36.55%	10.00%	3.66%
FVRB Increment	26.89%	1.25%	0.34%
Total	100.00%		6.37%

As shown in the above table, this alternative proposal provides for a non-zero return on the Fair Value Increment of UNS Gas, and provides for an overall fair value rate of return of 6.37 percent on the FVRB.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan

maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.
Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.
Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.
Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.
The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

UNS GAS INC
TOTAL COST OF CAPITAL

Item	Percent	Cost	Weighted Cost	
Long-Term Debt	50.01%	6.49%	3.25%	
Common Equity	49.99%	9.50% - 10.50%	4.75%	5.25%
Total	100.00%		7.99%	8.49%
			8.24%	**Mid-Point**

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Un-employment Rate	Consumer Price Index	Producer Price Index
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	5.9%	4.5%	1.6%	0.0%
1999	4.5%	4.3%	4.2%	2.7%	2.9%
2000	3.7%	4.2%	4.0%	3.4%	3.6%
2001	0.8%	-3.4%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.6%	-0.1%	5.8%	2.4%	1.2%
2003	2.5%	1.3%	6.0%	1.9%	4.0%
2004	3.6%	2.5%	5.5%	3.3%	4.2%
2005	2.9%	3.3%	5.1%	3.4%	5.4%
2006	2.8%	2.3%	4.6%	2.5%	1.1%
2007	2.0%	1.5%	4.6%	4.1%	6.2%
2008	1.1%	-2.2%	5.8%	0.1%	-0.9%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Un-employment Rate	Consumer Price Index	Producer Price Index
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.0%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	2.6%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.8%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	1.3%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	4.8%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.7%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	0.8%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	1.5%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.1%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	4.8%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	4.8%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	-0.2%	2.2%	4.8%	6.4%	10.8%
2008					
1st Qtr.	0.9%	1.8%	4.9%	2.8%	9.6%
2nd Qtr.	2.8%	-0.4%	5.3%	7.6%	14.0%
3rd Qtr.	-0.5%	-3.2%	6.0%	2.8%	-0.4%
4th Qtr.	-6.3%	-6.6%	6.9%	-13.6%	-27.6%
2009					
1st Qtr.	-6.1%	-11.8%	8.1%	2.4%	-1.2%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%		[1] 7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2003						
Jan	4.25%	1.17%	4.05%	6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%	6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%	6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%	6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%	6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%	6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%	6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%	6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%	6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%	6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%	6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%	6.18%	6.27%	6.61%
2004						
Jan	4.00%	0.89%	4.15%	6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%	6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%	5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%	6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%	6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%	6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%	6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%	5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%	5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%	5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%	5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%	5.78%	5.92%	6.10%
2005						
Jan	5.25%	2.32%	4.22%	5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%	5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%	5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%	5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%	5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%	5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%	5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%	5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%	5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%	5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%	5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%	5.55%	5.80%	6.14%
2006						
Jan	7.50%	4.20%	4.42%	5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%	5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%	5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%	6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%	6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%	6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%	6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.86%	5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%	5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%	5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%	5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%	5.62%	5.81%	6.05%
2007						
Jan	8.25%	4.96%	4.76%	5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%	5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%	5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%	5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%	5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%	6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%	6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%	6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%	6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%	6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%	5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%	6.03%	6.16%	6.51%
2008						
Jan	6.00%	2.86%	3.74%	5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%	6.04%	6.21%	6.60%
Mar	5.25%	1.38%	3.51%	5.99%	6.21%	6.68%
Apr	5.00%	1.32%	3.68%	5.99%	6.29%	6.82%
May	5.00%	1.71%	3.88%	6.07%	6.27%	6.79%
June	5.00%	1.90%	4.10%	6.19%	6.38%	6.93%
July	5.00%	1.72%	4.01%	6.13%	6.40%	6.97%
Aug	5.00%	1.79%	3.89%	6.09%	6.37%	6.98%
Sept	5.00%	1.46%	3.69%	6.13%	6.49%	7.15%
Oct	4.00%	0.84%	3.81%	6.95%	7.56%	8.58%
Nov	4.00%	0.30%	3.53%	6.83%	7.60%	8.98%
Dec	3.25%	0.04%	2.42%	5.93%	6.54%	8.13%
2009						
Jan	3.25%	0.12%	2.52%	6.01%	6.39%	7.90%
Feb	3.25%	0.31%	2.87%	6.11%	6.30%	7.74%
Mar	3.25%	0.25%	2.82%	6.14%	6.42%	8.00%
Apr	3.25%	0.17%	2.93%	6.20%	6.48%	8.03%

Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Year	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.55%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.57%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.01%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit___(DCP-1)
Schedule 3

UNISOURCE ENERGY CORPORATION
SEGMENT FINANCIAL INFORMATION
2006 - 2008
($millions)

Segment	Operating Revenues	Operating Income	Total Assets
		2006	
Tucson Electric Power Co	$989 75.6%	$216 90.0%	$2,623 82.3%
UNS Gas	$162 12.4%	$13 5.4%	$253 7.9%
UNS Electric	$160 12.2%	$13 5.4%	$195 6.1%
All Other	$14 1.1%	 0.0%	$1,038 32.6%
Unisource Energy	$1,308	$240	$3,187
		2007	
Tucson Electric Power Co	$1,071 77.6%	$189 88.7%	$2,573 80.8%
UNS Gas	$151 10.9%	$12 5.6%	$276 8.7%
UNS Electric	$169 12.2%	$12 5.6%	$231 7.3%
All Other	$12 0.9%	 0.0%	$1,077 33.8%
Unisource Energy	$1,381	$213	$3,186
		2008	
Tucson Electric Power Co	$1,079 77.2%	$107 73.8%	$2,842 81.0%
UNS Gas	$174 12.4%	$20 13.8%	$294 8.4%
UNS Electric	$195 13.9%	$12 8.3%	$285 8.1%
All Other	$23 1.6%	 0.0%	$1,061 30.2%
Unisource Energy	$1,398	$145	$3,510

UNS Gas, TEP and UNS Electric figures do not total to Unisource Energy cosolidated figures due to other activities of Unisource Energy.

Source: Unisource Energy Corporation 2008 Form 10-K.

UNS GAS
CAPITAL STRUCTURE RATIOS
2003 - 2008
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2004	$58.8	$100.0	
	37.0%	63.0%	0.0%
	37.0%	63.0%	
2005	$79.8	$100.0	
	44.4%	55.6%	0.0%
	44.4%	55.6%	
2006	$84.2	$100.0	
	45.7%	54.3%	0.0%
	45.7%	54.3%	
2007	$88.3	$100.0	
	46.9%	53.1%	0.0%
	46.9%	53.1%	
2008	$96.7	$100.0	
	49.2%	50.8%	0.0%
	49.2%	50.8%	

Source: Response to DP 5.2

UNISOURCE ENERGY CORP
CAPITAL STRUCTURE RATIOS
2003 - 2008
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2004	$581	$1,258	$0
	31.6%	68.4%	0.0%
	31.6%	68.4%	
2005	$617	$1,212	$5
	33.6%	66.1%	0.3%
	33.7%	66.3%	
2006	$654	$1,171	$50
	34.9%	62.5%	2.7%
	35.8%	64.2%	
2007	$690	$994	$10
	40.7%	58.7%	0.6%
	41.0%	59.0%	
2008	$679	$1,314	$10
	33.9%	65.6%	0.5%
	34.1%	65.9%	

Source: Unisource Energy Corporation 2008 Form 10-K.
Item 6. - Selected Consolidated Financial Data

UNISOURCE ENERGY AND UTILITY SUBSIDIARIES
CAPITAL STRUCTURE RATIOS
2008
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
Unisource Energy consolidated	$679.3 33.9% 34.1%	$1,313.6 65.6% 65.9%	$10.0 0.5%
UNS Gas	$96.7 49.2% 49.2%	$100.0 50.8% 50.8%	0.0%
UNS Electric	$83.8 43.7% 43.7%	$108.0 56.3% 56.3%	0.0%
TEP	$583.6 39.0% 39.2%	$903.6 60.4% 60.8%	$10.0 0.7%

Source for Unisource Energy Consolidated and TEP is 2008 10-K
Source for UNS Gas and UNS Electric is Response to DP 5.2

Exhibit___(DCP-1)
Schedule 5

PROXY GROUPS
COMMON EQUITY RATIOS

COMPANY	2004	2005	2006	2007	2008	Average	2012-2014
Parcell Proxy Group							
Avista Corp.	41.9%	40.6%	46.3%	59.0%	50.5%	47.0%	52.5%
Hawaiian Electric Industries, Inc	51.0%	53.3%	48.6%	51.0%	52.5%	51.3%	55.5%
Northeast Utilities	34.0%	35.1%	39.7%	39.2%	38.1%	37.2%	44.5%
Pinnacle West Capital Corp.	53.3%	56.8%	51.6%	53.0%	53.0%	53.5%	52.5%
Pepco Holdings, Inc.	39.6%	42.3%	45.1%	45.9%	48.5%	44.3%	48.5%
TECO Energy, Inc.	24.9%	30.0%	35.0%	39.0%	38.5%	33.5%	42.0%
Westar Energy, Inc.	45.5%	47.2%	49.3%	48.9%	49.9%	48.2%	54.0%
Average	41.5%	43.6%	45.1%	48.0%	47.3%	45.0%	49.9%
Grant Comparable Company Group							
AGL Resources	46.0%	48.1%	49.8%	49.8%	49.7%	48.7%	55.0%
Atmos Energy Corp	56.8%	42.3%	43.0%	48.0%	49.2%	47.9%	51.0%
Laclede Group	48.3%	51.8%	50.4%	54.6%	55.5%	52.1%	53.0%
New Jersey Resources Corp	59.7%	58.0%	65.2%	62.7%	61.5%	61.4%	67.0%
NICOR Inc	60.1%	62.5%	63.7%	69.0%	68.4%	64.7%	74.0%
Northwest Natural Gas Co	54.0%	53.0%	53.7%	53.7%	55.1%	53.9%	53.0%
Piedmont Natural Gas Co	56.4%	58.6%	51.7%	51.6%	52.8%	54.2%	53.0%
South Jersey Industries	51.0%	55.1%	55.3%	57.3%	60.8%	55.9%	59.5%
Southwest Gas Corp	35.8%	36.2%	39.4%	41.9%	44.7%	39.6%	49.0%
WGL Holdings	57.2%	58.6%	60.4%	60.3%	62.4%	59.8%	64.5%
Average	52.5%	52.4%	53.3%	54.9%	56.0%	53.8%	57.9%

Source: Value Line Investment Survey.

Exhibit___(DCP-1)
Schedule 6

PROXY COMPANIES

Company	Market Capitalization ($ millions)	Percent Reg Elec or Gas Revenues	S&P Bond Rating	Moody's Bond Rating	Common Equity Ratio	Value Line Safety
Unisource Energy	$900	85%	BBB	Baa2	27%	3
Parcell Proxy Group						
Avista Corp.	$1,100	50%	BBB+	Baa2	52%	3
Hawaiian Electric Industries, Inc.	$1,900	85%	BBB+	Baa2	53%	2
Northeast Utilities	$3,600	81%	BBB+	Baa1	38%	3
Pinnacle West Capital Corp.	$3,500	93%	BBB-	Baa2	53%	2
Pepco Holdings, Inc.	$3,400	73%	BBB+	A3	44%	3
TECO Energy, Inc.	$2,200	62%	BBB-	Baa2	39%	3
Westar Energy, Inc.	$1,800	70%	BBB-	Baa2	50%	2
Grant Comparable Company Group						
AGL Resources	$2,000	56%	A-	A3	39%	2
Atmos Energy Corp	$1,900	52%	BBB+	Baa3	46%	2
Laclede Group	$850	50%	BBB+	Baa1	57%	2
New Jersey Resources Corp	$1,400	30%	NR	NR	49%	1
NICOR Inc	$1,300	85%	AA	A1	44%	3
Northwest Natural Gas Co	$1,000	98%	AA-	A2	45%	1
Piedmont Natural Gas Co	$1,700	75%	A	A3	43%	2
South Jersey Industries	$1,000	58%	A	A3	47%	2
Southwest Gas Corp	$800	84%	BBB-	Baa3	43%	3
WGL Holdings	$1,500	59%	AA-	A2	50%	1

Sources: AUS Utility Reports, Value Line.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	February - April, 2009 DPS	HIGH	LOW	AVERAGE	YIELD
Parcell Proxy Group					
Avista Corp.	$0.72	$19.52	$12.67	$16.10	4.5%
Hawaiian Electric Industries, Inc.	$1.24	$22.73	$12.09	$17.41	7.1%
Northeast Utilities	$0.95	$25.25	$19.01	$22.13	4.3%
Pinnacle West Capital Corp.	$2.10	$35.13	$22.32	$28.73	7.3%
Pepco Holdings, Inc.	$1.08	$18.71	$10.07	$14.39	7.5%
TECO Energy, Inc.	$0.80	$12.71	$8.41	$10.56	7.6%
Westar Energy, Inc.	$1.20	$20.84	$14.86	$17.85	6.7%
Average					**6.4%**
Grant Comparable Company Group					
AGL Resources	$1.72	$34.93	$24.02	$29.48	5.8%
Atmos Energy Corp	$1.32	$26.17	$20.07	$23.12	5.7%
Laclede Group	$1.54	$47.20	$33.81	$40.51	3.8%
New Jersey Resources Corp	$1.24	$42.37	$29.95	$36.16	3.4%
NICOR Inc	$1.86	$36.34	$27.50	$31.92	5.8%
Northwest Natural Gas Co	$1.58	$45.66	$37.71	$41.69	3.8%
Piedmont Natural Gas Co	$1.08	$27.55	$20.68	$24.12	4.5%
South Jersey Industries	$1.19	$38.68	$31.98	$35.33	3.4%
Southwest Gas Corp	$0.90	$26.38	$17.08	$21.73	4.1%
WGL Holdings	$1.47	$35.52	$28.89	$32.21	4.6%
Average					**4.5%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2004	2005	2006	2007	2008	Average	2009	2010	2012-'14	Average
Parcell Proxy Group										
Avista Corp.	1.4%	2.4%	4.9%	0.8%	3.7%	2.6%	4.0%	3.5%	2.5%	3.3%
Hawaiian Electric Industries, Inc.	1.1%	1.5%	0.7%	0.8%	0.5%	0.9%	0.5%	2.5%	3.0%	2.0%
Northeast Utilities	1.6%	1.5%	0.3%	4.3%	5.3%	2.6%	4.5%	4.5%	4.5%	4.5%
Pinnacle West Capital Corp.	2.3%	1.0%	3.4%	2.5%	0.3%	1.9%	1.0%	2.0%	3.0%	2.0%
Pepco Holdings, Inc.	2.5%	2.4%	1.5%	2.3%	4.2%	2.6%	2.0%	3.0%	3.5%	2.8%
TECO Energy, Inc.	0.0%	3.3%	5.0%	5.1%	0.0%	2.7%	2.5%	4.0%	4.5%	3.7%
Westar Energy, Inc.	3.2%	4.3%	5.5%	4.3%	1.2%	3.7%	2.5%	2.5%	3.0%	2.7%
Average						**2.4%**				**3.0%**
Grant Comparable Company Group										
AGL Resources	5.6%	6.2%	6.3%	5.3%	5.0%	5.7%	4.5%	5.0%	6.0%	5.2%
Atmos Energy Corp	1.7%	2.3%	3.6%	3.0%	3.1%	2.7%	3.5%	3.5%	4.0%	3.7%
Laclede Group	2.7%	3.1%	5.1%	4.3%	5.2%	4.1%	6.0%	4.0%	5.0%	5.0%
New Jersey Resources Corp	7.8%	8.5%	6.3%	3.6%	9.5%	7.1%	6.5%	7.0%	5.5%	6.3%
NICOR Inc	2.1%	2.3%	5.2%	5.4%	3.6%	3.7%	3.0%	4.5%	5.5%	4.3%
Northwest Natural Gas Co	2.7%	3.7%	4.5%	6.0%	4.7%	4.3%	4.5%	4.5%	4.5%	4.5%
Piedmont Natural Gas Co	3.7%	3.6%	2.8%	3.5%	3.9%	3.5%	4.0%	5.0%	6.0%	5.0%
South Jersey Industries	5.9%	6.2%	10.2%	6.7%	6.8%	7.2%	7.0%	6.5%	7.0%	6.8%
Southwest Gas Corp	4.3%	2.2%	5.2%	4.8%	2.1%	3.7%	2.5%	3.5%	4.5%	3.5%
WGL Holdings	4.1%	4.6%	3.2%	3.5%	5.0%	4.1%	4.5%	4.5%	4.5%	4.5%
Average						**4.6%**				**4.9%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '06-'08 to '12-'14 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Parcell Proxy Group								
Avista Corp.	4.0%	5.0%	3.0%	4.0%	6.5%	12.5%	3.5%	7.5%
Hawaiian Electric Industries, Inc.	-6.0%	0.0%	1.0%	-1.7%	7.0%	0.0%	2.5%	3.2%
Northeast Utilities	3.0%	8.5%	2.0%	4.5%	8.0%	6.5%	5.0%	6.5%
Pinnacle West Capital Corp.	-1.0%	5.0%	3.0%	2.3%	3.0%	1.0%	1.0%	1.7%
Pepco Holdings, Inc.	-2.0%	17.5%	1.5%	5.7%	3.0%		2.5%	2.8%
TECO Energy, Inc.	-5.0%	-9.0%	-6.5%	-6.8%	4.5%	2.5%	4.5%	3.8%
Westar Energy, Inc.	32.0%	-5.0%	-4.5%	7.5%	4.0%	4.5%	6.0%	4.8%
Average				**2.2%**				**4.3%**
Grant Comparable Company Group								
AGL Resources	11.5%	6.5%	11.5%	9.8%	3.0%	2.5%	0.5%	2.0%
Atmos Energy Corp	5.0%	1.5%	7.5%	4.7%	4.0%	1.5%	4.0%	3.2%
Laclede Group	9.5%	1.5%	5.5%	5.5%	3.5%	2.5%	5.5%	3.8%
New Jersey Resources Corp	7.5%	5.0%	11.5%	8.0%	5.5%	5.5%	8.5%	6.5%
NICOR Inc	1.0%	0.5%	4.0%	1.8%	2.5%	0.0%	4.5%	2.3%
Northwest Natural Gas Co	6.5%	2.0%	3.5%	4.0%	7.0%	5.5%	3.5%	5.3%
Piedmont Natural Gas Co	6.5%	4.5%	6.0%	5.7%	7.5%	3.5%	5.0%	5.3%
South Jersey Industries	12.5%	4.5%	12.5%	9.8%	5.5%	7.0%	4.5%	5.7%
Southwest Gas Corp	8.0%	0.5%	4.0%	4.2%	4.5%	5.0%	2.5%	4.0%
WGL Holdings	4.0%	1.5%	4.5%	3.3%	4.0%	2.5%	5.0%	3.8%
Average				**5.7%**				**4.2%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Parcell Proxy Group								
Avista Corp.	4.6%	2.6%	3.3%	4.0%	7.5%	4.7%	4.4%	9.0%
Hawaiian Electric Industries, Inc.	7.2%	0.9%	2.0%		3.2%	4.8%	2.7%	9.9%
Northeast Utilities	4.4%	2.6%	4.5%	4.5%	6.5%	7.4%	5.1%	9.5%
Pinnacle West Capital Corp.	7.4%	1.9%	2.0%	2.3%	1.7%	4.5%	2.5%	9.9%
Pepco Holdings, Inc.	7.6%	2.6%	2.8%	5.7%	2.8%	3.7%	3.5%	11.1%
TECO Energy, Inc.	7.8%	2.7%	3.7%		3.8%	8.7%	4.7%	12.5%
Westar Energy, Inc.	6.9%	3.7%	2.7%	7.5%	4.8%	3.6%	4.5%	11.3%
Mean	6.6%	2.4%	3.0%	4.8%	4.3%	5.3%	3.9%	**10.5%**
Median	7.2%	2.6%	2.8%	4.5%	3.8%	4.7%	4.4%	**9.9%**
Composite - Mean		**9.0%**	9.6%	11.4%	10.9%	**11.9%**	10.5%	
Composite - Median		**9.8%**	10.1%	11.7%	11.1%	**11.9%**	11.6%	
Grant Comparable Company Group								
AGL Resources	6.0%	5.7%	5.2%	9.8%	2.0%	5.3%	5.6%	11.6%
Atmos Energy Corp	5.8%	2.7%	3.7%	4.7%	3.2%	5.0%	3.8%	9.7%
Laclede Group	3.9%	4.1%	5.0%	5.5%	3.8%	3.5%	4.4%	8.3%
New Jersey Resources Corp	3.5%	7.1%	6.3%	8.0%	6.5%	7.0%	7.0%	10.5%
NICOR Inc	5.9%	3.7%	4.3%	1.8%	2.3%	4.5%	3.3%	9.3%
Northwest Natural Gas Co	3.9%	4.3%	4.5%	4.0%	5.3%	4.8%	4.6%	8.5%
Piedmont Natural Gas Co	4.6%	3.5%	5.0%	5.7%	5.3%	7.0%	5.3%	9.9%
South Jersey Industries	3.5%	7.2%	6.8%	9.8%	5.7%	7.0%	7.3%	10.8%
Southwest Gas Corp	4.2%	3.7%	3.5%	4.2%	4.0%	6.0%	4.3%	8.5%
WGL Holdings	4.7%	4.1%	4.5%	3.3%	3.8%	4.0%	3.9%	8.6%
Mean	4.6%	4.6%	4.9%	5.7%	4.2%	5.4%	5.0%	**9.6%**
Median	4.4%	4.1%	4.8%	5.1%	3.9%	5.1%	4.5%	**9.5%**
Composite - Mean		9.2%	9.5%	**10.3%**	**8.8%**	10.0%	9.6%	
Composite - Median		8.5%	9.2%	**9.5%**	**8.3%**	**9.5%**	8.9%	

Sources: Prior pages of this schedule.

Exhibit___(DCP-1)
Schedule 8

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.29%	5.08%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
2007	$66.17	$529.59	12.80%	4.86%	7.94%
Average					**6.45%**

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

Exhibit___(DCP-1)
Schedule 9

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Parcell Proxy Group				
Avista Corp.	3.82%	0.70	5.32%	7.5%
Hawaiian Electric Industries, Inc.	3.82%	0.60	5.32%	7.0%
Northeast Utilities	3.82%	0.70	5.32%	7.5%
Pinnacle West Capital Corp.	3.82%	0.70	5.32%	7.5%
Pepco Holdings, Inc.	3.82%	0.80	5.32%	8.1%
TECO Energy, Inc.	3.82%	0.80	5.32%	8.1%
Westar Energy, Inc.	3.82%	0.75	5.32%	7.8%
Mean				**7.7%**
Median				**7.5%**
Grant Comparable Company Group				
AGL Resources	3.82%	0.75	5.32%	7.8%
Atmos Energy Corp	3.82%	0.60	5.32%	7.0%
Laclede Group	3.82%	0.65	5.32%	7.3%
New Jersey Resources Corp	3.82%	0.65	5.32%	7.3%
NICOR Inc	3.82%	0.75	5.32%	7.8%
Northwest Natural Gas Co	3.82%	0.60	5.32%	7.0%
Piedmont Natural Gas Co	3.82%	0.65	5.32%	7.3%
South Jersey Industries	3.82%	0.65	5.32%	7.3%
Southwest Gas Corp	3.82%	0.70	5.32%	7.5%
WGL Holdings	3.82%	0.65	5.32%	7.3%
Mean				**7.4%**
Median				**7.3%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

20-year Treasury Bonds

Month	Rate
Feb-09	3.83%
Mar-09	3.78%
Apr-09	3.84%

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	1992-2001 Average	2002-2008 Average	2009	2010	2012-14
Parcell Proxy Group																						
Avista Corp.	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	1.1%	13.4%	7.9%	4.5%	6.7%	4.6%	5.8%	8.8%	4.1%	8.2%	10.4%	6.1%	8.0%	8.0%	8.0%
Hawaiian Electric Industries, In	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	7.7%	8.1%	11.0%	9.6%	8.5%	10.0%	10.5%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	4.5%	8.6%	9.8%	3.8%	6.7%	8.5%	9.5%	8.5%
Pinnacle West Capital Corp.	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	7.9%	11.5%	8.2%	7.5%	8.0%	9.0%
Pepco Holdings, Inc.	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	7.1%	7.9%	9.0%	11.0%	8.2%	7.5%	8.5%	8.5%
TECO Energy, Inc.	16.1%	15.1%	14.5%	16.6%	16.5%	14.8%	13.5%	13.8%	17.4%	17.2%	13.5%	-0.7%	9.2%	14.2%	14.7%	14.3%	8.9%	15.6%	10.6%	11.0%	12.0%	12.0%
Westar Energy, Inc.	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.6%	6.7%	8.7%	8.0%	8.0%	8.0%
Average	11.9%	11.8%	11.5%	11.8%	10.1%	7.9%	9.0%	6.9%	9.1%	9.8%	8.5%	7.2%	7.5%	8.5%	9.2%	8.7%	8.4%	10.0%	8.3%	8.4%	9.1%	9.2%
Median	11.0%	12.0%	10.8%	11.1%	10.6%	10.9%	11.3%	11.1%	9.8%	11.9%	8.6%	7.6%	8.2%	8.1%	9.2%	8.5%	8.2%	11.1%	8.3%	8.0%	8.5%	8.5%
Grant Comparable Company Group																						
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	13.6%	12.8%	12.5%	11.8%	13.7%	12.5%	13.0%	14.5%
Atmos Energy Corp	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	10.0%	9.2%	9.0%	11.4%	9.7%	9.0%	8.5%	9.5%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	13.1%	12.0%	12.6%	11.3%	11.4%	12.5%	10.5%	11.0%
New Jersey Resources Corp	12.2%	11.8%	13.0%	13.3%	13.9%	14.5%	14.7%	15.0%	15.1%	15.2%	15.9%	16.8%	15.8%	16.2%	14.6%	10.2%	16.5%	13.9%	15.1%	13.5%	13.0%	11.0%
NICOR Inc	15.3%	15.3%	15.7%	14.6%	17.0%	16.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	12.8%	15.2%	14.9%	12.5%	16.2%	14.0%	11.0%	12.5%	12.0%
Northwest Natural Gas Co	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.9%	12.4%	11.2%	10.5%	10.2%	11.0%	11.0%	11.0%
Piedmont Natural Gas Co	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	11.0%	11.8%	12.4%	13.0%	11.7%	12.5%	13.5%	13.5%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	17.2%	13.3%	13.5%	12.2%	13.9%	13.5%	13.5%	14.5%
Southwest Gas Corp	5.1%	3.9%	7.5%	0.6%	1.7%	5.4%	10.4%	7.5%	7.3%	6.7%	6.6%	6.2%	8.8%	6.5%	9.7%	8.8%	6.1%	5.6%	7.5%	6.0%	7.5%	9.0%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	10.8%	11.0%	12.0%	12.4%	11.3%	12.0%	11.5%	11.0%
Average	10.9%	11.9%	11.5%	11.1%	12.7%	12.6%	12.0%	11.1%	11.9%	12.5%	11.3%	12.3%	11.9%	11.6%	12.6%	11.6%	11.8%	11.8%	11.9%	11.4%	11.5%	11.7%
Median	11.8%	12.4%	11.9%	12.3%	13.6%	12.9%	11.9%	10.2%	11.5%	11.9%	10.6%	12.3%	12.2%	11.9%	12.0%	11.9%	12.4%	12.1%	11.9%	12.3%	12.0%	11.0%

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	1992-2001 Average	2002-2008 Average
Parcell Proxy Group																			
Avista Corp.	151%	163%	133%	125%	145%	162%	163%	152%	317%	114%	85%	94%	111%	115%	135%	126.7%	110%	163%	111%
Hawaiian Electric Industries,	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166.4%	164%	147%	169%
Northeast Utilities	154%	149%	127%	124%	95%	64%	91%	113%	136%	129%	99%	95%	106%	108%	131%	162.5%	128%	118%	119%
Pinnacle West Capital Corp.	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	127.1%	97%	136%	120%
Pepco Holdings, Inc.	160%	162%	135%	138%	161%	151%	161%	166%	139%	124%	110%	103%	109%	122%	129%	141.3%	110%	150%	118%
TECO Energy, Inc.	243%	268%	224%	238%	241%	234%	247%	210%	223%	222%	135%	111%	174%	243%	202%	187.5%	174%	235%	175%
Westar Energy, Inc.	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	139.8%	106%	118%	119%
Average	163%	168%	141%	146%	150%	149%	160%	144%	166%	138%	109%	111%	134%	149%	151%	150%	127%	152%	133%
Median	154%	154%	133%	129%	145%	151%	161%	143%	139%	129%	110%	109%	130%	130%	135%	141%	110%	144%	124%
Grant Comparable Company Group																			
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	188.2%	146.0%	179%	179%
Atmos Energy Corp	158%	194%	186%	196%	248%	241%	246%	216%	167%	170%	150%	152%	147%	145%	146%	136.1%	109.8%	202%	141%
Laclede Group	158%	187%	178%	163%	168%	175%	174%	159%	141%	155%	145%	169%	179%	179%	184%	167.7%	209.3%	166%	176%
New Jersey Resources Corp	161%	186%	162%	178%	191%	229%	225%	224%	226%	224%	220%	245%	251%	275%	246%	222.6%	200.0%	201%	237%
NICOR Inc	179%	216%	195%	187%	220%	242%	260%	226%	227%	239%	199%	185%	210%	222%	234%	228.7%	200.0%	219%	211%
Northwest Natural Gas Co	162%	176%	161%	146%	156%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	208.1%	201.0%	155%	171%
Piedmont Natural Gas Co	180%	214%	186%	182%	183%	217%	222%	213%	195%	199%	186%	211%	212%	208%	221%	209.9%	237.0%	199%	212%
South Jersey Industries	154%	175%	141%	142%	146%	178%	209%	202%	196%	205%	185%	170%	195%	221%	209%	231.2%	195.9%	175%	201%
Southwest Gas Corp	81%	100%	103%	103%	121%	129%	139%	147%	120%	127%	123%	118%	127%	135%	161%	149.4%	144.9%	117%	137%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	172.4%	146.0%	180%	168%
Average	159%	183%	165%	163%	180%	197%	202%	187%	175%	181%	168%	174%	183%	193%	193%	191%	179%	179%	183%
Median	161%	188%	167%	168%	181%	191%	203%	189%	173%	180%	162%	169%	182%	187%	185%	198%	198%	180%	183%

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2007

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
Averages:		
1992-2001	14.7%	341%
2002-2007	13.9%	284%

Source: Standard & Poor's Analyst's Handbook, 2008 edition, page 1.

Exhibit___(DCP-1)
Schedule 12

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B
Parcell Proxy Group	2.6	0.72	B+	B
Grant Comparable Company Group	1.9	0.67	A-	A-

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

Exhibit___(DCP-1)
Schedule 13

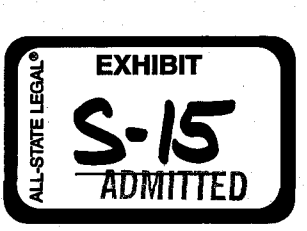
UNS GAS INC
RATING AGENCY RATIOS

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost	
Long-Term Debt	50.01%	6.49%	3.25%	3.25%	
Common Equity	49.99%	10.00%	5.00%	8.33%	
Total	100.00%		8.24%	11.58%	1/

1/ Post-tax weighted cost divided by .60 (composite tax factor)

Pre-Tax coverage = **3.57**
11.58% /3.25%

Standard & Poor's Utility Benchmark Ratios: Business Profile of "4"	A	BBB
Pre-tax coverage	3.3x - 4.0x	2.2x - 3.0x
Total debt to total capital	45%-52%	52%-62%



BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571

SURREBUTTAL

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JULY 29, 2009

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NO. G-04204A-08-0571

My Surrebuttal testimony is in response to the rebuttal testimony of UNS Gas, Inc. ("UNS Gas") witness Kentton C. Grant. My Surrebuttal testimony responds to the following general areas of Mr. Grant's rebuttal testimony: cost of common equity, ability of UNS Gas to earn its cost of capital and Fair Value Rate of Return.

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ABILITY OF UNS GAS TO EARN ITS COST OF CAPITAL	7
RATE OF RETURN ON FAIR VALUE RATE BASE	7

INTRODUCTION

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

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. Are you the same David C. Parcell who filed direct testimony on behalf of the Utilities Division Staff earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your current testimony?

A. My current testimony is surrebuttal testimony in response to the rebuttal testimony of UNS Gas, Inc. ("UNS Gas") witness Kentton C. Grant.

Q. What aspects of Mr. Grant's rebuttal testimony do you respond to in this surrebuttal testimony?

A. My surrebuttal testimony responds to the following general areas of Mr. Grant's rebuttal testimony:

Cost of Common Equity;

Ability of UNS Gas to Earn its Cost of Capital; and

Fair Value Rate of Return

COST OF COMMON EQUITY

Q. Mr. Grant claims, on page 1, that your cost of equity recommendation falls "well below the actual cost of equity to UNS Gas." What is your response to this assertion?

A. I believe that my cost of equity recommendation is appropriate for UNS Gas at this time. This cost of equity recommendation is based upon the results of my Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM") and Comparable Earnings ("CE") analyses and has been performed in a similar fashion to my recent testimonies before this Commission. I note that my 10.0 percent recommendation matches the cost of equity that the Commission found appropriate for UNS Gas in its most recent proceeding (i.e., Docket No. G-04204A-06-0463). There has been no demonstration that the cost of capital has increased since the 2007 proceeding of UNS Gas. I also note that this Commission determined that 10.0 percent was the fair cost of equity for Southwest Gas in a 2008 proceeding (Docket No. G-01551A-07-0504), which was applied to a lower percentage of common equity than is the case for UNS Gas in the current proceeding.

Q. Mr. Grant also maintains, on pages 1-2, that your testimony does not "properly take into account the substantial deterioration in capital market conditions and increase to the cost of capital that has occurred since September of 2008." Do you agree with this claim?

A. No, I do not. I demonstrated in my direct testimony, on pages 14-15 and 38-40, that the events since September of 2008 largely reflect the "flight to safety" that accompanied the unprecedented (in recent memory) decline in the equity markets as a result of the collapse of the subprime mortgage market and the ultimate near-meltdown in the financial system. The events of the last two years have impacted virtually all aspects of the economy and society, not just utilities and UNS Gas. The customers of UNS Gas have also been adversely impacted by these same conditions, in terms of lay-offs, decline in real estate

values, disintegration of the values of IRAs/401Ks, and the other implications of the severe recession in Arizona. Another aspect of this economic/financial decline is lower returns earned (if even positive) by competitive firms in both Arizona and the U.S. This decline reflects a reduction in the opportunity cost of capital, not an increase as proposed by Mr. Grant.

Q. Mr. Grant claims, on page 4, that each of your three cost of equity analyses "contain significant flaws that serve to significantly understate the cost of equity capital to UNS Gas." What is your response to this?

A. I disagree with Mr. Grant. The analyses that I use have been presented to this Commission several times in recent years and my recommendations, including those for UNS Gas and UNS Electric, have been accepted by the Commission.

Q. Mr. Grant maintains, on pages 4-6, that the CAPM model, and in particular the historic risk premium component, "is not applicable in today's capital markets." He also claims, on page 8, that your CAPM risk-free rate reflects the "flight to safety" but you did not "adjust" the market risk premium. What is your response to these assertions?

A. It is apparent that the CAPM results are lower than the DCF results, as well as being lower than CAPM results in recent years. The two reasons for the lower CAPM results are the current relatively low yields on U.S. Treasury bonds (i.e., risk-free rate) and a lower risk premium that reflects the decline in stock prices in 2008. However, these currently lower CAPM results are only one-half of the impact of recent economic conditions. The other impact is on the DCF results which are somewhat higher currently due to the higher yields attributable to the decline in stock prices. It would not be proper to disregard the lower CAPM results while not discounting the higher DCF results.

Q. On pages 5-7, Mr. Grant claims that investors are more "risk averse" and that spreads between government and corporate/utility yields are demonstrative of an increased cost of capital for utilities and UNS Gas. Do you agree with this?

A. No, I do not. As I indicated in my direct testimony, most of this increase in yield spreads results from the "flight to safety" that resulted from the decline in the equity markets (i.e., some 40 percent decline) that left investors unwilling to invest in common stocks at this time. This reflects more of an "availability of capital" as I indicated on pages 14-15 of my direct testimony. In addition, as Mr. Grant acknowledges on page 7, utility stocks have fared better than most common stocks during this time, again reflecting a "flight to safety."

Q. Mr. Grant further maintains, on pages 9-10, that your use of both geometric and arithmetic means in your CAPM analysis is not proper. What is your response to this?

A. It is apparent that investors have access to both types of returns and correspondingly use both types of returns, when they make investment decisions. In fact, it is noteworthy that mutual fund investors regularly receive reports on their own funds, as well as prospective funds they are considering investing in that show only geometric returns. Based on this, I find it difficult to accept Mr. Grant's position that only arithmetic returns are considered by investors and, thus, only arithmetic returns are appropriate in a CAPM context. I note that I provided additional comments on this point in my direct testimony.

Q. Has this Commission recently made a finding as to whether it is appropriate to use geometric as well as arithmetic returns in this context?

A. Yes, it has. In Decision No. 70360, in the recent UNS Electric case (Docket No. E-04204A-06-0783) the Commission specifically stated (page 43) that it agreed with the use

of geometric returns in this manner: "We agree with the Staff that it is appropriate to consider the geometric returns in calculating a comparable company CAPM because to do otherwise would fail to give recognition to the fact that many investors have access to such information for purposes of making investment decisions."

Q. Mr. Grant indicates his belief, on page 10, that "income returns" (which he uses) is superior to "total returns" (which you use). What is your response to this?

A. I addressed this issue in my direct testimony on page 42.

Q. On pages 11-13, Mr. Grant takes issue with the growth rates you examine in your DCF analyses. What is your response to this?

A. Mr. Grant maintains that the growth rates I examine in my DCF analyses are too low to reflect investor expectations. In making this assertion, he relies heavily on his perception that I used the "average" of the five sets of growth rates in reaching my conclusions. However, as an examination of page 28 of my direct testimony reveals, my 9.5 percent to 10.5 percent conclusion includes DCF rates using most of the individual growth rates, not just the average. Whereas, I did not give much weight to the "outliers" of growth rates for the proxy group, my conclusion incorporates all of the individual growth rates for Mr. Grant's proxy group.

I also note that the existence of "low" growth rates does not imply that investors do not give consideration to these in reaching their investment decisions. This is especially true in the recent and current economic environment where the recovery of both the economy and earnings growth rates is problematic at best. Nevertheless, as I indicate in my direct testimony, I do not give weight to the low "outlier" growth rates in my DCF conclusions.

Q. Mr. Grant suggests, on page 13, that you should have added an additional 1.5 percent to the growth rates in your DCF analyses. Do you agree with that assertion?

A. No, it would not be appropriate to include/add 1.5 percent to the growth rates. Investors may desire higher growth rates, but they have no right to expect them if such an expectation is not supported by data or realistic information.

Q. Mr. Grant also criticizes your comparable earnings analyses on page 14. What is your response to this position?

A. I disagree with Mr. Grant. The book value of UNS Gas' capital, including common equity, is used to determine the Company's cost of capital. It is only natural that the returns on book value of equity (i.e., comparable earnings analyses) is an appropriate mechanism for estimating the cost of equity. Mr. Grant also claims that this Commission has rejected the comparable earnings approach. I note that I am not aware of any cases in which I have appeared that the Commission has reached this conclusion.

Q. Mr. Grant also maintains, on page 15, that market-to-book ratios do not indicate investor acceptance of earned returns. Is he correct?

A. No, he is not. Stock prices – one component of the market-to-book ratio – reflect all relevant information. For public utilities, the return on equity is a major component of the rate-setting process and clearly is reflected in stock prices, and thus market-to-book ratios. I also note that I consider expected returns on equity in my comparable earnings analysis.

Q. On page 17, Mr. Grant claims to have "recalculated" your cost of equity results. Is this a proper exercise?

A. No, it is not. Mr. Grant's "recalculations" are simply his attempt to interject his DCF, CAPM, and CE components into my analyses. Such recalculations are incorrect and improper.

ABILITY OF UNS GAS TO EARN ITS COST OF CAPITAL

Q. Mr. Grant devotes several pages of his rebuttal testimony to his assertion that UNS Gas will not likely earn the cost of capital authorized in this proceeding. Is this a proper criticism of your direct testimony?

A. I do not believe it is proper rebuttal to my testimony. Mr. Grant seems to be taking the position that the cost of capital authorized by a commission should be regarded as a "guarantee" but this is not the case. Utility investors have no more "right" to a guaranteed return than do its ratepayers to a "right" to employment, maintenance of their housing values, and an increasing value of their retirement accounts and other investments.

RATE OF RETURN ON FAIR VALUE RATE BASE

Q. Mr. Grant maintains, on page 28, that your Fair Value Rate of Return ("FVROR") recommendation to apply a zero percent return to the Fair Value Increment amounts to a "backing in" method of assigning a FVROR. Do you agree with his assessment?

A. No, I do not. My proposal specifically recognizes the value of the Fair Value Rate Base ("FVRB") increment and applies the actual cost of this capital (which is zero) to it. As such, I believe this proposal specifically recognizes and utilizes the FVRB in establishing rates.

Q. Mr. Grant also claims, on pages 28-30, that since the Commission did not adopt your FVROR proposal in the Chaparral City remand proceeding (Docket No. W-02113A-04-0616) that your proposal has been "rejected." What is your response to this?

A. I note, first of all, that the FVROR proposal of Chaparral City was the same as that proposed by UNS Gas and UNS Electric in their 2007 rate proceedings (Docket Nos. G-04204A-06-0463 and E-04204A-06-0783), namely that the original cost rate of return be applied the level of FVRB. In all three of these cases, the Commission did not adopt the Chaparral City/UNS Gas & Electric position. In the UNS Gas and UNS Electric cases, the Commission did adopt my recommendation. It is my reading of the Chaparral City remand order by the Commission that a similar procedure to that which I recommended was adopted.

I also note that the Commission noted in its Chaparral City remand order "we also believe that Staff's method is an appropriate way to adjust the Weighted Average Cost of Capital associated with the Original Cost Rate Base for use with the FVRB, as it is based on sound economic and financial theory.

Q. What is the basis of the 6.80 percent FVROR recommended by Mr. Grant?

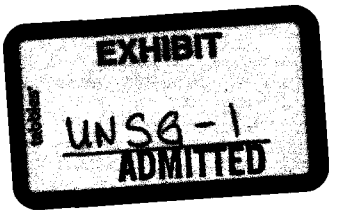
A. This is not apparent from Mr. Grant's direct or rebuttal testimonies. Mr. Grant's only guidance as to UNS Gas' derivation of the 6.80 percent FVROR is that its "reduction (from a 7.30 percent value that the Company apparently believes could have been requested) was a voluntary measure."

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

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



IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-____ **APPLICATION**

UNS Gas, Inc. ("UNS Gas" or "Company"), pursuant to A.R.S. §§ 40-250, 40-251, and A.A.C. R14-2-103, hereby files an Application for an increase in its base rates of $9.5 million, or approximately 6% over test year revenues, and to set UNS Gas' fair value rate base at $256 million. UNS Gas requests that the new rates become effective not later than December 1, 2009.

UNS Gas' current rates and charges, which were approved by the Arizona Corporation Commission ("Commission") in Decision No. 70011 (November 27, 2007), do not produce a reasonable return on the fair value of its property devoted to public service and are therefore not just and reasonable. The rate increase sought is required to enable the Company to earn a fair rate of return on the fair value of its assets devoted to public service, and will provide for recovery of the Company's operating and capital costs necessarily and prudently incurred in rendering adequate utility service to customers. The requested increase is necessary for UNS Gas to operate as a financially healthy utility that can ensure UNS Gas customers continued reliable service, on demand, and at reasonable prices into the future.

In connection with its request for increased revenues, UNS Gas is also asking the Commission to design rates that recover a greater share of the Company's fixed costs through a higher fixed monthly customer charge. Presently, customers in colder areas, like Flagstaff,

continue to subsidize customers in warmer areas. This modification will reduce this inequity, and help ensure that all customers are paying their fair share. This change serves to create rates that treat customers across the Company's diverse service territory more equitably, while balancing the interests of the Company and its customers. This rate design results in an average 6% increase to a customer's total bill compared to test year revenues, inclusive of gas costs. The effect on the fixed monthly and delivery charges on an average customer's bill will be an increase in those components of approximately 19% compared to test year revenues, excluding gas cost recovery.

Finally, through this Application, as set forth in more detail in the accompanying testimony, UNS Gas is requesting the Commission to approve requested changes to the Company's Rules and Regulations and a minor change to the Company's purchased gas adjustor mechanism.

In support of this Application, UNS Gas respectfully states as follows:

I.

The Company is a corporation duly organized, existing and in good standing under the laws of the State of Arizona. Its principal place of business is 2901 West Shamrell, Flagstaff, Arizona 86001.

II.

The Company is a public service corporation principally engaged in the transmission and distribution of natural gas for sale in Arizona pursuant to Certificates of Convenience and Necessity issued by the Commission.

III.

All communications and correspondence concerning this Application, as well as communications and pleadings with respect thereto filed by other parties, should be served upon the following:

Raymond S. Heyman, Esq.
Phillip J. Dion, Esq.
Michelle Livengood, Esq.
UniSource Energy Corporation
One South Church, Suite 200
Tucson, Arizona 85701

and

Michael W. Patten, Esq.
Jason D. Gellman, Esq.
Roshka, DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

IV.

This Commission has jurisdiction to conduct public hearings to determine the fair value of the property of a public service corporation, to fix a just and reasonable rate of return thereon, and thereafter, to approve rate schedules designed to develop such return. Further, the Commission has jurisdiction to establish the practices and procedures to govern the conduct of such hearing, including, but not limited to, such matters as notice, intervention, filing, service, exhibits, discovery, and other prehearing and hearing matters.

V.

Accompanying this Application are the standard filing requirements and rate design schedules described in A.A.C. R14-2-103 and the Direct Testimony and related exhibits of the following witnesses:

- David G. Hutchens
- Kentton C. Grant
- Dallas J. Dukes
- Karen G. Kissinger
- Gary A. Smith
- D. Bentley Erdwurm
- Denise A. Smith

VI.

UNS Gas respectfully requests that this Commission set a date for a hearing on this Application such that new rates for the Company will become effective on December 1, 2009. At the hearing conducted pursuant to this rate request, UNS Gas will establish, among other things, that:

(1) its current rates and charges do not permit the Company to earn a fair return on the fair value of its assets devoted to public service and are therefore no longer just and reasonable;

(2) the requested increase is the minimum amount necessary to allow the Company an opportunity to earn a fair return on the fair value of its assets devoted to public service, for preservation of the Company's financial integrity and for the attraction of new capital on reasonable terms;

(3) the Company requires additional permanent base revenue of at least $9.5 million based on annualized test period sales in order to continue to provide adequate and reliable gas service to its customers as required by law;

(4) the proposed rate design will better align the fixed and variable costs of service with the rates paid by the customers causing those costs and is in the public interest; and

(5) the proposed modifications to UNS Gas' tariffs (specifically, its Rules and Regulations) should be approved.

VII.

In addition to setting a hearing date, UNS Gas asks that the Commission issue a procedural order setting forth the prescribed notice for the Application, establishing procedures for intervention, and providing for appropriate discovery. UNS Gas further requests that the Company should be authorized to serve all discovery requests, answers and objections electronically. Hard copy service would remain available to parties upon request or where the confidential nature of the information makes the use of electronic service impractical.

WHEREFORE, UNS Gas respectfully requests that the Commission:

(1) issue a procedural order establishing a date for hearing evidence concerning the Application, prescribing the time and form of notice to UNS Gas customers and establishing procedures for intervention and discovery as described above;

(2) issue a final order granting the Company the permanent rate increase sought herein;

(3) issue a final order approving the new or modified rate and service schedules included with the Company's Application with an effective date no later than December 1, 2009;

(4) issue a final order approving the proposed rate design described in the testimony accompanying this Application;

(5) issue a final order approving UNS Gas' revised Rules and Regulations, which were submitted with this Application and related testimony; and

(6) grant the Company such additional relief as the Commission deems just and proper.

RESPECTFULLY SUBMITTED this 7th day of November 2008.

UNS Gas, Inc.

By _____

Raymond S. Heyman
Phillip J. Dion
Michelle Livengood
UniSource Energy Services
One South Church Avenue, Suite 200
Tucson, Arizona 85701

and

Michael W. Patten
Jason D. Gellman
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Attorneys for UNS Gas, Inc.

Original and 13 copies of the foregoing filed this 7th day of November, 2008, with:

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

Copy of the foregoing hand-delivered this 7th day of November, 2008, to:

Chairman Mike Gleason
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner William A. Mundell
Arizona Corporation Commission
1200 West Washington Street
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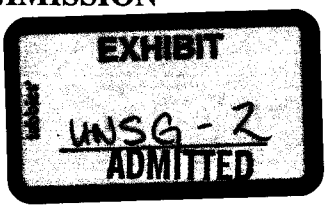
By Mary Ippolito

BEFORE THE ARIZONA CORPORATION COMMISSION



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

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-

UNS GAS, INC.

SCHEDULES

VOLUME 3 OF 3

November 7, 2008

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Schedule A

UNS Gas, Inc.
Computation of Increase in Gross Revenue Requirements
Test Year Ended June 30, 2008

Line No.	Description	ACC Jurisdiction Original Cost		RCND		Fair Value		Line No.
1	Adjusted Rate Base	$182,293,105	(a)	$329,268,770	(a)	$255,779,938	(e)	1
2	Adjusted Operating Income	$11,600,004	(b)	$11,600,004	(b)	$11,600,004		2
3	Current Rate of Return (2/1)	6.36%		3.52%		4.54%		3
4	Required Operating Income	$17,393,036		$17,393,036		$17,393,036		4
5	Weighted Average Cost of Capital	8.75%	(c)	8.75%		8.75%		5
6	Fair Value Adjustment	0.79%		-3.47%		-1.95%		6
7	Required Rate of Return	9.54%		5.28%		6.80%	(e)	7
8	Operating Income Deficiency	$5,793,032		$5,793,032		$5,793,032		8
9	Gross Revenue Conversion Factor	1.6366	(d)	1.6366	(d)	1.6366	(d)	9
10	Increase in Gross Revenue Requirement	$9,480,876		$9,480,876		$9,480,876		10

	Customer Classification	Projected Revenue Increase (f)	% Dollar Increase (f)	
11	Residential Service	$6,673,621	18.34%	11
12	Commercial Gas Service	1,874,298	19.39%	12
13	Industrial Gas Service	48,123	18.86%	13
14	Public Authority Gas Service	338,437	19.02%	14
15	Special Gas Light Service	12,812	19.14%	15
16	Irrigation Service	6,437	19.01%	16
17	Transportation Customers	527,149	18.37%	17
18	Total	$9,480,876	18.53%	18

Supporting Schedules
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(b) C-1
(c) D-1
(d) C-3
(e) Rev Req Model
(f) H-1

UNS Gas, Inc.
Summary Results of Operations
Prior Years Ended December 31, 2006 and 2007, Test Year Ended June 30, 2008
and Projected Year Ended June 30, 2009
(Thousands of Dollars)

Line No.	Description	Prior Years Ended December 31, 2006 (a)	Prior Years Ended December 31, 2007 (a)	Test Year Ended June 30, 2008 Actuals (b)	Test Year Ended June 30, 2008 Adjusted (b)	Projected Year Ended June 30, 2009 Present Rates (c)	Projected Year Ended June 30, 2009 Proposed Rates (c)	Line No.
1	Operating Revenues	$162,017	$150,953	$163,396	$52,903	$193,031	$202,907	1
2	Operating Expenses (includes income taxes)	151,301	141,057	149,949 (2)	41,303	180,324	184,266	2
3	Operating Income	10,716	9,896	13,447	11,600	12,707	18,641	3
4	Other Income and Deductions	386	903	379	379	361	438	4
5	Income Before Interest Expense	11,102	10,798	13,826	11,979	13,068	19,079	5
6	Interest Expense	6,714	6,805	6,652	6,652	6,353	6,345	6
7	Net Income	$4,388	$3,993	$7,174	$5,327	$6,715	$12,734	7
8	Earnings Per Average Common Share	N/A (1)	N/A	N/A	N/A	N/A	N/A	8
9	Dividends Per Common Share	N/A (1)	N/A	N/A	N/A	N/A	N/A	9
10	Payout Ratio	0% (1)	0%	0%	0%	0%	0%	10
11	Return on Year-End Invested Capital	6.06%	5.76%	6.97%	6.09%	6.36%	9.02%	11
12	Return on Average Invested Capital	6.14%	5.83%	7.18%	6.24%	6.47%	9.31%	12
13	Return on Year-End Common Equity	5.21%	4.52%	7.23%	5.47%	6.34%	11.37%	13
14	Return on Average Common Equity	5.35%	4.63%	7.68%	5.76%	6.54%	12.06%	14
15	Times Total Interest Earned - Before Income Taxes	2.04	1.89	2.74	2.34	2.75	4.32	15
16	Times Total Interest Earned - After Income Taxes	1.65	1.59	2.08	1.80	2.06	3.01	16

(1) UNS Gas, Inc. is a subsidiary of UniSource Energy Corporation and has no publicly traded stock; thus, such information is not meaningful.
(2) Includes reclassification of $137,200 for Customer Deposit Interest Expense From Other Interest Expense to Other O&M Expense.

Supporting Schedules
(a) E-2
(b) C-1
(c) F-1

UNS Gas, Inc.
Summary of Capital Structure
Prior Years Ended December 31, 2006 and 2007, Test Year Ended June 30, 2008
and Projected Year Ended June 30, 2009
(Thousands of Dollars)

Line No.	Description	Prior Years Ended December 31, 2006 (a)	Prior Years Ended December 31, 2007 (a)	Test Year Ended June 30, 2008 Actuals (b)	Projected Year June 30, 2009 Present Rates (b)	Projected Year June 30, 2009 Proposed Rates (b)	Line No.
	Capitalization						
1	Short-Term Debt	$0	$0	$0	$0	$0	1
2	Long-Term Debt (Net of Issuance Costs)	$98,994	$99,181	$99,265	99,430	99,430	2
	Total Debt	98,994	99,181	99,265	99,430	99,430	
3	Common Stock Equity	84,154	88,265	99,242	105,959	111,974	3
4	Total Capital	$183,148	$187,446	$198,507	$205,389	$211,404	4
	Capitalization Ratios						
5	Short-Term Debt	0.00%	0.00%	0.00%	0.00%	0.00%	5
6	Long-Term Debt (Net of Issuance Costs)	54.05%	52.91%	50.01%	48.41%	47.03%	6
7	Common Stock Equity	45.95%	47.09%	49.99%	51.59%	52.97%	7
8	Total Capital	100.00%	100.00%	100.00%	100.00%	100.00%	8
9	Weighted Cost of Short-Term Debt	N/A	N/A	N/A	0.00%	N/A	9
10	Weighted Cost of Long-Term Debt	3.51%	3.43%	3.25%	3.14%	3.05%	10
11	Weighted Cost of Common Equity	5.05%	5.18%	5.50%	5.67%	5.83%	11

Supporting Schedules
(a) E-1
(b) D-1

UNS Gas, Inc.
Construction Expenditures and Gross Utility Plant in Service
Prior Years Ended December 31, 2006 and 2007, Test Year Ended June 30, 2008
and Projected Years Ended December 31, 2009, 2010 and 2011
(Thousands of Dollars)

Line No.	Year		Construction Expenditures	Net Plant Placed in Service (1)	Gross Utility Plant in Service (1)	Line No.
1	Prior Year Ended December 31, 2006	(a)	$22,976	$183,933	$265,598	1
2	Prior Year Ended December 31, 2007	(a)	$22,083	$195,016	$278,659	2
3	Test Year Ended June 30, 2008	(a)	$20,012	$203,242	$290,369	3
4	Projected Year Ended December 31, 2009	(b)	$23,247	$229,951	$332,375	4
5	Projected Year Ended December 31, 2010	(b)	$20,147	$240,241	$353,642	5
6	Projected Year Ended December 31, 2011	(b)	$22,451	$251,537	$376,537	6

(1) Net Plant Placed in Service and Gross Utility Plant in Service exclude CWIP and Plant Held For Future Use.

Supporting Schedules
(a) E-1 & E-3
(b) F-3

UNS Gas, Inc.
Summary Changes in Financial Position
Prior Years Ended December 31, 2006 and 2007, Test Year Ended June 30, 2008
and Projected Year Ended June 30, 2009
(Thousands of Dollars)

Line No.	Description	Prior Years Ended December 31, 2006 (a)	Prior Years Ended December 31, 2007 (a)	Test Year Ended June 30, 2008 (a)	Projected Year Ended June 30, 2009 Present Rates (b)	Projected Year Ended June 30, 2009 Proposed Rates (b)	Line No.
1	Net Cash Flows from Operating Activities	$31,506	$28,368	$17,208	$16,457	$24,175	1
2	Net Cash Flows From Investing Activities	(22,976)	(22,083)	(20,012)	(25,650)	(25,650)	2
3	Net Cash Flows from Financing Activities	(3,890)	(5,673)	(1,543)	(1,109)	(1,110)	3
4	Net Increase (Decrease) in Cash	$4,640	$612	($4,347)	($10,302)	($2,585)	4

Supporting Schedules
(a) E-3
(b) F-2

Schedule B

UNS Gas, Inc.
Summary of Original Cost and RCND Rate Base
Test Year Ended June 30, 2008

Line No.	Description	Total		ACC Jurisdiction		Line No.
		Adjusted Original Cost Rate Base (a)	Adjusted RCND Rate Base (b)	Adjusted Original Cost Rate Base (a)	Adjusted RCND Rate Base (b)	
1	Gross Utility Plant in Service	$318,227,624	$561,025,858	$318,227,624	$561,025,858	1
2	Less: Accumulated Depreciation	87,543,544	152,278,962	87,543,544	152,278,962	2
3	Net Utility Plant in Service	230,684,080	408,746,896	230,684,080	408,746,896	3
4	Southern Union Acquisition Premium	0	0	0	0	4
5	Less: Accum. Amort. - So. Union Acq. Premium	0	3,553	0	3,553	5
6	Net Southern Union Acquisition Premium	0	(3,552)	0	(3,552)	6
7	Citizens Acquisition Discount	(30,709,737)	(55,126,579)	(30,709,737)	(55,126,579)	7
8	Less: Accum. Amort. - Citizens Acq. Discount	(3,935,647)	(6,658,438)	(3,935,647)	(6,658,438)	8
9	Net Citizens Acquisition Discount	(26,774,091)	(48,468,141)	(26,774,091)	(48,468,141)	9
10	Total Net Utility Plant	203,909,989	360,275,203	203,909,989	360,275,203	10
11	Customer Advances for Construction	(11,235,876)	(12,759,773)	(11,235,876)	(12,759,773)	11
12	Customer Deposits	(2,609,271)	(2,609,271)	(2,609,271)	(2,609,271)	12
13	Accumulated Deferred Income Taxes	(10,606,875)	(18,474,527)	(10,606,875)	(18,474,527)	13
14	Total Deductions	(24,452,022)	(33,843,571)	(24,452,022)	(33,843,571)	14
15	Allowance for Working Capital	2,364,921	2,364,921	2,364,921	2,364,921	15
16	Regulatory Assets	492,590	492,590	492,590	492,590	16
17	Regulatory Liabilities	(22,372)	(22,372)	(22,372)	(22,372)	17
18	Total Rate Base	$182,293,105	$329,266,770	$182,293,105	$329,266,770	18

Supporting Schedules
(a) B-2
(b) B-3

Recap Schedules
A-1

UNS Gas, Inc.
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended June 30, 2008

Line No.	Description		Actual at End of Test Period	Total Adjustments (a)	Adjusted at End of Test Period	ACC Jurisdiction	Line No.
1	Gross Utility Plant in Service		$340,154,214	($21,926,590)	$318,227,624	$318,227,624	1
2	Less: Accumulated Depreciation		93,765,398	(6,221,854)	87,543,544	87,543,544	2
3	Net Utility Plant in Service		246,388,816	(15,704,736)	230,684,080	230,684,080	3
4	Southern Union Acquisition Premium		18,271,349	(18,271,349)	0	0	4
5	Less: Accum. Amort. - So. Union Acq. Premium		2,125,967	(2,125,967)	0	0	5
6	Net Southern Union Acquisition Premium		16,145,381	(16,145,381)	0	0	6
7	Citizens Acquisition Discount		(68,391,292)	37,681,555	(30,709,737)	(30,709,737)	7
8	Less: Accum. Amort. - Citizens Acq. Discount		(8,764,777)	4,829,130	(3,935,647)	(3,935,647)	8
9	Net Citizens Acquisition Discount		(59,626,516)	32,852,425	(26,774,091)	(26,774,091)	9
10	Total Net Utility Plant		202,907,681	1,002,308	203,909,989	203,909,989	10
11	Customer Advances for Construction		(11,825,028)	589,152	(11,235,876)	(11,235,876)	11
12	Customer Deposits		(2,609,271)	0	(2,609,271)	(2,609,271)	12
13	Accumulated Deferred Income Taxes		(15,056,983)	4,450,108	(10,606,875)	(10,606,875)	13
14	Total Deductions		(29,491,282)	5,039,260	(24,452,022)	(24,452,022)	14
15	Working Capital	(b)	2,266,954	97,967	2,364,921	2,364,921	15
16	Regulatory Assets		492,590	0	492,590	492,590	16
17	Regulatory Liabilities		(22,372)	0	(22,372)	(22,372)	17
18	Total Original Cost Rate Base		$176,153,570	$6,139,535	$182,293,105	$182,293,105	18

Supporting Schedules
(a) B-2 (P2-3)
(b) B-5

Recap Schedules
B-1

UNS Gas, Inc.
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended June 30, 2008

Line No.	Description	Pro Forma Adjustments: Acquisition Adjustment	So. Union Acq. Premium	Griffith Power Plant	Build-Out Plant	Golden Valley Plant	Post-Test Year Non-Revenue Plant in Service	Total Page Adjustments	Line No.
1	Gross Utility Plant in Service	$0	$0	($6,184,403)	($12,841,090)	($4,428,685)	$1,527,588	($21,926,590)	1
2	Less: Accumulated Depreciation	0	0	(1,241,803)	(4,944,462)	(35,589)	0	(6,221,854)	2
3	Net Utility Plant in Service	0	0	(4,942,600)	(7,896,628)	(4,393,096)	1,527,588	(15,704,736)	3
4	Southern Union Acquisition Premium	0	(18,271,349)	0	0	0	0	(18,271,349)	4
5	Less: Accum. Amort. - So. Union Acq. Premium	0	(2,125,967)	0	0	0	0	(2,125,967)	5
6	Net Southern Union Acquisition Premium	0	(16,145,381)	0	0	0	0	(16,145,381)	6
7	Citizens Acquisition Discount	37,681,555	0	0	0	0	0	37,681,555	7
8	Less: Accum. Amort. - Citizens Acq. Discount	4,829,130	0	0	0	0	0	4,829,130	8
9	Net Citizens Acquisition Discount	32,852,425	0	0	0	0	0	32,852,425	9
10	Total Net Utility Plant	32,852,425	(16,145,381)	(4,942,600)	(7,896,628)	(4,393,096)	1,527,588	1,002,308	10
11	Customer Advances for Construction	0	0	0	0	0	0	0	11
12	Customer Deposits	0	0	0	0	0	0	0	12
13	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	13
14	Total Deductions	0	0	0	0	0	0	0	14
15	Allowance for Working Capital	0	0	0	0	0	0	0	15
16	Regulatory Assets	0	0	0	0	0	0	0	16
17	Regulatory Liabilities	0	0	0	0	0	0	0	17
18	Total Original Cost Rate Base	$32,852,425	($16,145,381)	($4,942,600)	($7,896,628)	($4,393,096)	$1,527,588	$1,002,308	18

Supporting Schedules
N/A

Recap Schedules
B-1

UNS Gas, Inc.
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended June 30, 2008

Line No.	Description	Pro Forma Adjustments: Customer Advances Adjustment	Pro Forma Adjustments: Accumulated Deferred Income Taxes (a)	Pro Forma Adjustments: Working Capital (a)	Pro Forma Adjustments	Pro Forma Adjustments	Total Page Adjustments	Total Original Cost Adjustments	Line No.
1	Gross Utility Plant in Service	$0	$0	$0	$0	$0	$0	($21,926,590)	1
2	Less: Accumulated Depreciation	0	0	0	0	0	0	(6,221,854)	2
3	Net Utility Plant in Service	0	0	0	0	0	0	(15,704,736)	3
4	Southern Union Acquisition Premium	0	0	0	0	0	0	(18,271,349)	4
5	Less: Accum. Amort. - So. Union Acq. Premium	0	0	0	0	0	0	(2,125,967)	5
6	Net Southern Union Acquisition Premium	0	0	0	0	0	0	(16,145,381)	6
7	Citizens Acquisition Discount	0	0	0	0	0	0	37,681,555	7
8	Less: Accum. Amort. - Citizens Acq. Discount	0	0	0	0	0	0	4,829,130	8
9	Net Citizens Acquisition Discount	0	0	0	0	0	0	32,852,425	9
10	Total Net Utility Plant	0	0	0	0	0	0	1,002,308	10
11	Customer Advances for Construction	589,152	0	0	0	0	589,152	589,152	11
12	Customer Deposits	0	0	0	0	0	0	0	12
13	Accumulated Deferred Income Taxes	0	4,450,108	0	0	0	4,450,108	4,450,108	13
14	Total Deductions	589,152	4,450,108	0	0	0	5,039,260	5,039,260	14
15	Allowance for Working Capital	0	0	97,967	0	0	97,967	97,967	15
16	Regulatory Assets	0	0	0	0	0	0	0	16
17	Regulatory Liabilities	0	0	0	0	0	0	0	17
18	Total Original Cost Rate Base	$589,152	$4,450,108	$97,967	$0	$0	$5,137,227	$6,139,535	18

Supporting Schedules
(a) B-5

Recap Schedules
B-1

UNS Gas, Inc.
Pro Forma Adjustments to RCND Rate Base
Test Year Ended June 30, 2008

Line No.	Description	Actual at End of Test Period (a), (b)	Total Adjustments (c)	Adjusted at End of Test Period	ACC Jurisdiction	Line No.
1	Gross Utility Plant in Service	$599,893,441	($38,867,583)	$561,025,858	$561,025,858	1
2	Less: Accumulated Depreciation	163,532,158	(11,253,197)	152,278,962	152,278,962	2
3	Net Utility Plant in Service	436,361,283	(27,614,387)	408,746,896	408,746,896	3
4	Southern Union Acquisition Premium	33,786,916	(33,786,916)	0	0	4
5	Less: Accum. Amort. - So. Union Acq. Premium	3,861,229	(3,857,676)	3,553	3,553	5
6	Net Southern Union Acquisition Premium	29,925,688	(29,929,240)	(3,552)	(3,552)	6
7	Citizens Acquisition Discount	(122,768,160)	67,641,581	(55,126,579)	(55,126,579)	7
8	Less: Accum. Amort. - Citizens Acq. Discount	(14,824,245)	8,165,807	(6,658,438)	(6,658,438)	8
9	Net Citizens Acquisition Discount	(107,943,915)	59,475,774	(48,468,141)	(48,468,141)	9
10	Total Net Utility Plant	358,343,056	1,932,147	360,275,203	360,275,203	10
11	Customer Advances for Construction	(13,428,830)	669,057	(12,759,773)	(12,759,773)	11
12	Customer Deposits	(2,609,271)	0	(2,609,271)	(2,609,271)	12
13	Accumulated Deferred Income Taxes	(26,225,504)	7,750,977	(18,474,527)	(18,474,527)	13
14	Total Deductions	(42,263,605)	8,420,034	(33,843,571)	(33,843,571)	14
15	Allowance for Working Capital	2,266,954	97,967	2,364,921	2,364,921	15
16	Regulatory Assets	492,590	0	492,590	492,590	16
17	Regulatory Liabilities	(22,372)	0	(22,372)	(22,372)	17
18	Total RCND Rate Base	$318,816,622	$10,450,149	$329,266,770	$329,266,770	18

Supporting Schedules
(a) B-4
(b) B-2
(c) B-3 (P2-3)

Recap Schedules
B-1

UNS Gas, Inc.
Pro Forma Adjustments to RCND Rate Base
Test Year Ended June 30, 2008

Line No.	Description	Pro Forma Adjustments: Acquisition Adjustment RCN	So. Union Acq. Premium RCN	Griffith Power Plant RCN	Build-Out Plant RCN	Golden Valley Plant RCN	Post-Test Year Non-Revenue Plant in Service RCN	Total Page Adjustments	Line No.
1	Gross Utility Plant in Service	$0	$0	($9,095,229)	($24,234,984)	($8,051,797)	$2,514,427	($38,867,583)	1
2	Less: Accumulated Depreciation	0	0	(1,824,705)	(9,364,311)	(64,181)	0	(11,253,197)	2
3	Net Utility Plant in Service	0	0	(7,270,524)	(14,870,673)	(7,987,617)	2,514,427	(27,614,387)	3
4	Southern Union Acquisition Premium	0	(33,786,916)	0	0	0	0	(33,786,916)	4
5	Less: Accum. Amort. - So. Union Acq. Premium	0	(3,857,676)	0	0	0	0	(3,857,676)	5
6	Net Southern Union Acquisition Premium	0	(29,929,241)	0	0	0	0	(29,929,240)	6
7	Citizens Acquisition Discount	67,641,581	0	0	0	0	0	67,641,581	7
8	Less: Accum. Amort. - Citizens Acq. Discount	8,165,807	0	0	0	0	0	8,165,807	8
9	Net Citizens Acquisition Discount	59,475,774	0	0	0	0	0	59,475,774	9
10	Total Net Utility Plant	59,475,774	(29,929,241)	(7,270,524)	(14,870,673)	(7,987,617)	2,514,427	1,932,147	10
11	Customer Advances for Construction	0	0	0	0	0	0	0	11
12	Customer Deposits	0	0	0	0	0	0	0	12
13	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	13
14	Total Deductions	0	0	0	0	0	0	0	14
15	Allowance for Working Capital	0	0	0	0	0	0	0	15
16	Regulatory Assets	0	0	0	0	0	0	0	16
17	Regulatory Liabilities	0	0	0	0	0	0	0	17
18	Total RCND Rate Base	$59,475,774	($29,929,241)	($7,270,524)	($14,870,673)	($7,987,617)	$2,514,427	$1,932,147	18

Supporting Schedules
N/A

Recap Schedules
B-1

UNS Gas, Inc.
Pro Forma Adjustments to RCND Rate Base
Test Year Ended June 30, 2008

Line No.	Description	Pro Forma Adjustments: Customer Advances Adjustment RCN	Accumulated Deferred Income Taxes RCN (a)	Working Capital RCN (a)			Total Page Adjustments	Total Original Cost Adjustments	Line No.
1	Gross Utility Plant in Service	$0	$0	$0	$0	$0	$0	($38,867,583)	1
2	Less: Accumulated Depreciation	0	0	0	0	0	0	(11,253,197)	2
3	Net Utility Plant in Service	0	0	0	0	0	0	(27,614,387)	3
4	Southern Union Acquisition Premium	0	0	0	0	0	0	(33,786,916)	4
5	Less: Accum. Amort. - So. Union Acq. Premium	0	0	0	0	0	0	(3,857,676)	5
6	Net Southern Union Acquisition Premium	0	0	0	0	0	0	(29,929,240)	6
7	Citizens Acquisition Discount	0	0	0	0	0	0	67,641,581	7
8	Less: Accum. Amort. - Citizens Acq. Discount	0	0	0	0	0	0	8,165,807	8
9	Net Citizens Acquisition Discount	0	0	0	0	0	0	59,475,774	9
10	Total Net Utility Plant	0	0	0	0	0	0	1,932,147	10
11	Customer Advances for Construction	669,057	0	0	0	0	669,057	669,057	11
12	Customer Deposits	0	0	0	0	0	0	0	12
13	Accumulated Deferred Income Taxes	0	7,750,977	0	0	0	7,750,977	7,750,977	13
14	Total Deductions	669,057	7,750,977	0	0	0	8,420,034	8,420,034	14
15	Allowance for Working Capital	0	0	97,967	0	0	97,967	97,967	15
16	Regulatory Assets	0	0	0	0	0	0	0	16
17	Regulatory Liabilities	0	0	0	0	0	0	0	17
18	Total RCND Rate Base	$669,057	$7,750,977	$97,967	$0	$0	$8,518,001	$10,450,149	18

Supporting Schedules
(a) B-5

Recap Schedules
B-1

UNS Gas, Inc.
RCND By Major Plant Accounts
Test Year Ended June 30, 2008

Line No.	Function	Plant Account	Description	RCN	Percent	RCND	Line No.
1	INTANGIBLE	302	Franchises & Consents	362,992	49.0%	177,845	1
2		303	Misc. Intangible Plant	916,294	62.7%	574,718	2
3			Total Intangible Plant	1,279,286		752,562	3
4	TRANSMISSION	365	Land & Rights	102,606	81.4%	83,569	4
5		366	Structures & Improvements	21,228	72.8%	15,447	5
6		367	Mains	33,822,292	78.6%	26,574,998	6
7		369	Measuring and Req. Equipment	5,024,900	74.1%	3,722,508	7
8		371	Other Equipment	275,060	50.0%	137,568	8
9			Total Transmission Plant	39,246,087		30,534,089	9
10	DISTRIBUTION	374	Land & Rights	257,989	86.3%	222,637	10
11		375	Structures & Improvements	23,864	28.7%	6,842	11
12		376	Mains	334,472,111	75.5%	252,537,944	12
13		378	Meas. And Req. Equipment - General	4,253,911	70.8%	3,012,180	13
14		379	Meas. And Req. Equipment - City Gate	5,250,952	85.5%	4,488,257	14
15		380	Services	141,077,195	68.9%	97,153,552	15
16		381	Meters	25,877,829	55.3%	14,301,327	16
17		382	Meter Installation	13,688,983	78.8%	10,792,880	17
18		383	Regulators	3,793,840	63.7%	2,415,339	18
19		384	Regulator Installations	1,832,533	85.9%	1,573,774	19
20		385	Industiral Measuring Equipment	3,341,054	53.9%	1,799,787	20
21		387	Other Equipment	1,877,231	51.0%	957,603	21
22			Total Distribution Plant	535,747,492		389,262,122	22
23	GENERAL	389	Land & Rights	394,121	96.6%	380,646	23
24		390	Structures & Improvements	7,005,670	94.6%	6,630,354	24
25		391	Office Furniture & Equipment	2,353,750	29.9%	703,788	25
26		392	Transportation Equipment	7,482,913	51.9%	3,882,007	26
27		393	Stores Equipment	245,842	82.3%	202,242	27
28		394	Tools, Shop, & Garage Equipment	2,815,683	68.2%	1,919,162	28
29		395	Laboratory Equipment	592,998	44.9%	266,295	29
30		396	Power Operated Equipment	1,337,097	80.8%	1,080,818	30
31		397	Communication Equipment	1,040,704	49.7%	517,507	31
32		398	Misc. Equipment	351,798	65.3%	229,692	32
33			Total General Plant	23,620,577		15,812,509	33
34			Total Plant	$599,893,441	72.7%	$436,361,283	34

Supporting Schedules
N/A

Recap Schedules
B-3

UNS Gas, Inc.
RCND By Major Plant Accounts
Test Year Ended June 30, 2008

Line No.	Function	Plant Account	Description	RCN	Percent	RCND	Line No.
			Southern Union Acquisition Premium				
1	INTANGIBLE	302	Franchises & Consents	20,652	80.5%	16,616	1
2		303	Misc. Intangible Plant	179,532	79.0%	141,822	2
3			Total Intangible Plant	200,184		158,438	3
4	DISTRIBUTION	376	Mains	23,539,148	89.5%	21,066,683	4
5		378	Meas. And Req. Equipment - General	345,955	85.0%	294,019	5
6		379	Meas. And Req. Equipment - City Gate	369,718	88.2%	326,073	6
7		380	Services	5,969,873	85.8%	5,124,209	7
8		381	Meters	1,589,532	89.9%	1,428,530	8
9		382	Meter Installation	9,676	88.1%	8,521	9
10		383	Regulators	(144,335)	86.9%	(125,479)	10
11		385	Industiral Measuring Equipment	629,352	87.3%	549,488	11
12		387	Other Equipment	334,155	85.0%	284,080	12
13			Total Distribution Plant	32,643,074		28,956,123	13
14	GENERAL	389	Land & Rights	133,238	97.3%	129,685	14
15		390	Structures & Improvements	229,032	85.7%	196,273	15
16		391	Office Furniture & Equipment	23,776	75.2%	17,879	16
17		393	Stores Equipment	31,982	86.5%	27,679	17
18		394	Tools, Shop, & Garage Equipment	540,816	83.1%	449,443	18
19		396	Power Operated Equipment	(14,263)	63.6%	(9,066)	19
20		398	Misc. Equipment	(923)	83.0%	(766)	20
21			Total General Plant	943,659		811,127	21
22			Total Plant	$33,786,916	88.6%	$29,925,688	22

Supporting Schedules
N/A

Recap Schedules
B-3

UNS Gas, Inc.
RCND By Major Plant Accounts
Test Year Ended June 30, 2008

Line No.	Function	Plant Account	Description	RCN	Percent	RCND	Line No.
			Citizens Acquisition Discount				
1	INTANGIBLE	302	Franchises & Consents	(81,207)	80.7%	(65,549)	1
2		303	Misc. Intangible Plant	(94,856)	79.6%	(75,529)	2
3			Total Intangible Plant	(176,063)		(141,079)	3
4	TRANSMISSION	365	Land & Rights	(34,352)	99.2%	(34,075)	4
5		366	Structures & Improvements	(6,598)	74.4%	(4,909)	5
6		367	Mains	(5,417,121)	93.6%	(5,069,118)	6
7		369	Measuring and Req. Equipment	(1,328,941)	91.5%	(1,216,639)	7
8		371	Other Equipment	(80,708)	78.4%	(63,284)	8
9			Total Transmission Plant	(6,867,720)		(6,388,026)	9
10	DISTRIBUTION	374	Land & Rights	(86,374)	99.5%	(85,968)	10
11		375	Structures & Improvements	(1,199)	84.4%	(1,012)	11
12		376	Mains	(77,055,149)	89.6%	(69,026,852)	12
13		378	Meas. And Req. Equipment - General	(713,890)	85.1%	(607,695)	13
14		379	Meas. And Req. Equipment - City Gate	(739,235)	88.2%	(652,318)	14
15		380	Services	(24,209,482)	85.9%	(20,790,901)	15
16		381	Meters	(4,855,395)	90.0%	(4,368,146)	16
17		382	Meter Installation	(2,629,951)	88.2%	(2,318,776)	17
18		383	Regulators	(523,021)	87.2%	(455,823)	18
19		384	Regulator Installations	(248,195)	86.2%	(213,861)	19
20		385	Industiral Measuring Equipment	(547,774)	87.3%	(478,111)	20
21		387	Other Equipment	(534,877)	84.8%	(453,770)	21
22			Total Distribution Plant	(112,144,541)		(99,453,233)	22
23	GENERAL	389	Land & Rights	(109,570)	97.5%	(106,779)	23
24		390	Structures & Improvements	(361,725)	81.0%	(293,006)	24
25		391	Office Furniture & Equipment	(1,618,817)	39.0%	(630,749)	25
26		392	Transportation Equipment	(200,931)	-18.8%	37,828	26
27		393	Stores Equipment	(48,416)	85.3%	(41,318)	27
28		394	Tools, Shop, & Garage Equipment	(639,517)	82.5%	(527,566)	28
29		395	Laboratory Equipment	(173,418)	53.2%	(92,225)	29
30		396	Power Operated Equipment	(13,568)	73.0%	(9,900)	30
31		397	Communication Equipment	(330,294)	69.8%	(230,682)	31
32		398	Misc. Equipment	(83,579)	80.4%	(67,179)	32
33			Total General Plant	(3,579,836)		(1,961,577)	33
34			*Total Plant*	($122,768,160)	87.9%	($107,943,915)	34

Supporting Schedules
N/A

Recap Schedules
B-3

UNS Gas, Inc.
Computation of Working Capital
Test Year Ended June 30, 2008

Line No.	Description	Total		Original & RCND	Line No.
		Original Cost	RCND Cost	ACC Jurisdiction	
1	Cash Working Capital	$1,568	$1,568	$1,568	1
2	Materials & Supplies (Accounts 154 and 163)	2,010,788	2,010,788	2,010,788	2
3	Prepayments	352,564	352,564	352,564	3
4	Total Working Capital Allowance	$2,364,920	$2,364,920	$2,364,920	4

Supporting Schedules
B-5 (P2)

Recap Schedules
B-1

UNS Gas, Inc.
Detail of Adjustments to Working Capital
Test Year Ended June 30, 2008

Line No.	Description	Actual	Adjustments		Total Adjusted	Line No.
			Thirteen Month Average	Cash Working Capital		
1	Cash Working Capital	$0	N/A	$1,568	$1,568	1
2	Materials & Supplies (Accounts 154 and 163)	2,010,060	728	N/A	2,010,788	2
3	Prepayments	256,893	95,671	N/A	352,564	3
4	Total	$2,266,954	$96,399	$1,568	$2,364,920	4

Supporting Schedules
B-5 (P3)

Recap Schedules
B-5 (P1)

UNS Gas, Inc.
Cash Working Capital - Lead/Lag Study
Test Year Ended June 30, 2008

Line No.	Description	Pro Forma Test Year Amount	Revenue Lag Days	Expense Lag Days	Net Lag Days (Col. C - Col. D)	Lead/Lag Factor (Col. E/365)	Cash Working Capital Required (Col. F x Col. B)	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	
	Operating Expenses							
	Non-Cash Expenses							
1	Bad Debts Expense	$688,379						1
2	Depreciation	9,057,437						2
3	Amortization	(817,432)						3
4	Deferred Income Taxes	2,869,418						4
	Other Operating Expenses							
5	Salaries and Wages	7,750,405	40.70	24.50	16.20	0.0444	$344,118	5
6	Incentive Compensation	310,278	40.70	267.00	(226.30)	(0.6200)	(192,372)	6
7	Purchased Gas Costs	87,528,793	40.70	27.89	12.81	0.0351	3,072,261	7
8	Office Supplies and Expenses	1,057,383	40.70	20.72	19.98	0.0547	57,839	8
9	Injuries and Damages	508,477	40.70	64.75	(24.05)	(0.0659)	(33,509)	9
10	Pensions and Benefits	1,544,121	40.70	54.66	(13.96)	(0.0382)	(58,985)	10
11	Support Services - TEP	7,079,463	40.70	44.75	(4.05)	(0.0111)	(78,582)	11
12	Property Taxes	3,610,079	40.70	213.00	(172.30)	(0.4721)	(1,704,318)	12
13	Payroll Taxes	560,124	40.70	19.41	21.29	0.0583	32,655	13
14	Current Income Taxes	734,254	40.70	41.42	(0.72)	(0.0020)	(1,469)	14
15	Interest on Customer Deposits	137,200	40.70	182.50	(141.80)	(0.3885)	(53,302)	15
16	Other Operations and Maintenance	6,212,916	40.70	53.10	(12.40)	(0.0340)	(211,239)	16
17	Total Operating Expenses	$128,831,296						17
	Other Cash Working Capital Elements:							
18	Interest On Long-Term Debt	$5,924,526	40.70	89.50	(48.80)	(0.1337)	(792,109)	18
19	Revenue Taxes and Assessments	$13,847,423	40.70	50.70	(10.00)	(0.0274)	(379,419)	19
20	Total Cash Working Capital						$1,568	20

Supporting Schedules
N/A

Recap Schedules
B-2, B-3

Schedule C

UNS Gas, Inc.
Adjusted Test Year Income Statement
Test Year Ended June 30, 2008

Line No.	Description	Unadjusted (a)	Pro Forma Adjustments (b)	Adjusted	ACC Jurisdiction	FERC Jurisdiction	Line No.
	Operating Revenues						
1	Gas Retail Revenues	$161,759,581	($110,601,818)	$51,157,763	$51,157,763	$0	1
2	Other Operating Revenue	1,636,425	108,318	1,744,743	1,744,743	0	2
3	Total Operating Revenues	163,396,006	(110,493,500)	52,902,506	52,902,506	0	3
	Operating Expenses						
4	Purchased Gas	109,328,534	(108,930,899)	397,635	397,635	0	4
5	Other Operations and Maintenance Expense	24,753,535 (1)	(34,422)	24,719,113	24,719,113	0	5
6	Depreciation and Amortization	8,437,470	(197,465)	8,240,005	8,240,005	0	6
7	Taxes Other than Income Taxes	3,000,914	1,341,164	4,342,078	4,342,078	0	7
8	Income Taxes	4,428,062	(824,391)	3,603,671	3,603,671	0	8
9	Total Operating Expenses	149,948,515	(108,646,013)	41,302,502	41,302,502	0	9
10	Operating Income	13,447,491	($1,847,487)	$11,600,004	$11,600,004	$0	10
	Other Income and Deductions						
11	Allowance for Equity Funds	137,755					
12	Other - Net	241,016					
13	Total Other Income and Deductions	378,771					
14	Income Before Interest Expense	13,826,262					
	Interest Expense						
15	Interest on Long-Term Debt	6,429,478					
16	Other Interest Expense	324,398 (1)					
17	Allowance for Borrowed Funds	(101,633)					
18	Total Interest Expense	6,652,243					
19	Net Income Available for Common Stock	$7,174,019					

(1) Includes reclassification of $137,200 for Customer Deposit Interest Expense *From Other* Interest Expense to Other O&M Expense.

Supporting Schedules	Recap Schedules
(a) E-2	A-1
(b) C-2	A-2

UNS Gas, Inc.
Income Statement Pro Forma Adjustments
Test Year Ended June 30, 2008

Line No.	Description	Griffith Plant Operations	Golden Valley Rev & Exp	Gas Cost Rev & Purch Gas Cost	NSP Revenue & Gas Cost	Rate Case Revenue Annualization	Customer Annualization	Total Page Adjustments	Line No.
	Operating Revenues								
1	Gas Retail Revenues	($865,152)	($2,148,778)	($90,472,202)	($17,165,706)	$1,448,476	($516,003)	($109,719,365)	1
2	Other Operating Revenue	0	0	0	0	0	0	0	2
3	Total Operating Revenues	(865,152)	(2,148,778)	(90,472,202)	(17,165,706)	1,448,476	(516,003)	(109,719,365)	3
	Operating Expenses								
4	Purchased Gas	0	(1,762,029)	(90,472,202)	(16,696,668)	0	0	(108,930,899)	4
5	Other Operations and Maintenance Expense	(160,390)	(1,900)	0	0	0	0	(162,290)	5
6	Depreciation and Amortization	0	0	0	0	0	0	0	6
7	Taxes Other than Income Taxes	0	(18)	0	0	0	0	(18)	7
8	Income Taxes	0	0	0	0	0	0	0	8
9	Total Operating Expenses	(160,390)	(1,763,947)	(90,472,202)	(16,696,668)	0	0	(109,093,207)	9
10	Operating Income	($704,762)	($384,831)	$0	($469,038)	$1,448,476	($516,003)	($626,158)	10

Supporting Schedules	Recap Schedules
N/A	C-1

UNS Gas, Inc.
Income Statement Pro Forma Adjustments
Test Year Ended June 30, 2008

Line No.	Description	Weather Normalization	DSM Revenue & Expense	Service Fees & Late Fees	Payroll Expense	Payroll Tax Expense	Pension and Benefits	Total Page Adjustments	Line No.
	Operating Revenues								
1	Gas Retail Revenues	($882,453)	$0	$0	$0	$0	$0	($882,453)	1
2	Other Operating Revenue	0	(130,917)	239,235	0	0	0	108,318	2
3	Total Operating Revenues	(882,453)	(130,917)	239,235	0	0	0	(774,135)	3
	Operating Expenses								
4	Purchased Gas	0	0	0	0	0	0	0	4
5	Other Operations and Maintenance Expense	0	(128,701)	0	362,018	0	77,544	310,861	5
6	Depreciation and Amortization	0	0	0	0	0	0	0	6
7	Taxes Other than Income Taxes	0	(2,216)	0	0	2,557	0	341	7
8	Income Taxes	0	0	0	0	0	0	0	8
9	Total Operating Expenses	0	(130,917)	0	362,018	2,557	77,544	311,202	9
10	Operating Income	($882,453)	$0	$239,235	($362,018)	($2,557)	($77,544)	($1,085,337)	10

Supporting Schedules	Recap Schedules
N/A	C-1

UNS Gas, Inc.
Income Statement Pro Forma Adjustments
Test Year Ended June 30, 2008

Line No.	Description	Incentive Compensation	Rate Case Expense	CARES Expense	CARES Regulatory Asset Amort.	Y2K Amortization	Miscellaneous Expenses	Total Page Adjustments	Line No.
	Operating Revenues								
1	Gas Retail Revenues	$0	$0	$0	$0	$0	$0	$0	1
2	Other Operating Revenue	0	0	0	0	0	0	0	2
3	Total Operating Revenues	0	0	0	0	0	0	0	3
	Operating Expenses								
4	Purchased Gas	0	0	0	0	0	0	0	4
5	Other Operations and Maintenance Expense	29,310	200,000	30,950	0	0	(812,448)	(552,188)	5
6	Depreciation and Amortization	0	0	(56,933)	164,197	(76,753)	0	30,511	6
7	Taxes Other than Income Taxes	1,620	0	0	0	0	(14,853)	(13,233)	7
8	Income Taxes	0	0	0	0	0	0	0	8
9	Total Operating Expenses	30,930	200,000	(25,983)	164,197	(76,753)	(827,301)	(534,910)	9
10	Operating Income	($30,930)	($200,000)	$25,983	($164,197)	$76,753	$827,301	$534,910	10

Supporting Schedules	Recap Schedules
N/A	C-1

UNS Gas, Inc.
Income Statement Pro Forma Adjustments
Test Year Ended June 30, 2008

Line No.	Description	Normalize Outside Legal Expense	Bad Debt Expense	Depr. & Amort. Exp. Annualization	Property Tax	Income Taxes		Total Page Adjustments	Total Adjustments	Line No.
	Operating Revenues									
1	Gas Retail Revenues	$0	$0	$0	$0	$0	$0	$0	($110,601,818)	1
2	Other Operating Revenue	0	0	0	0	0	0	0	108,318	2
3	Total Operating Revenues	0	0	0	0	0	0	0	(110,493,500)	3
	Operating Expenses									
4	Purchased Gas	0	0	0	0	0	0	0	(108,930,899)	4
5	Other Operations and Maintenance Expense	305,984	63,211	0	0	0	0	369,195	(34,422)	5
6	Depreciation and Amortization	0	0	(227,976)	0	0	0	(227,976)	(197,465)	6
7	Taxes Other than Income Taxes	0	0	0	1,354,074	0	0	1,354,074	1,341,164	7
8	Income Taxes	0	0	0	0	(824,391)	0	(824,391)	(824,391)	8
9	Total Operating Expenses	305,984	63,211	(227,976)	1,354,074	(824,391)	0	670,902	(108,646,013)	9
10	Operating Income	($305,984)	($63,211)	$227,976	($1,354,074)	$824,391	$0	($670,902)	($1,847,487)	10

Supporting Schedules	Recap Schedules
N/A	C-1

UNS Gas, Inc.
Computation of Gross Revenue Conversion Factor
Test Year Ended June 30, 2008

Line No.	Description	Percentage of Incremental Gross Revenues		Line No.
1	Gross Revenue	100.00%		1
2	Less: Uncollectible Revenue	0.48700%		2
3	Taxable Income as a Percent	99.51%		3
4	Less: Federal (31.630%) and State Income Taxes (6.968%) (Combined Effective Tax Rate = 38.598%)	38.41%		4
5	Change in Net Operating Income	61.10%		5
6	Gross Revenue Conversion Factor	1.6366	(a)	6

(a) Line No. 1 divided by line No. 5.

Supporting Schedules	Recap Schedules
N/A	A-1

Schedule D

UNS Gas, Inc.
Summary Cost of Capital
Test Year Ended June 30, 2008
(Thousands of Dollars)

Line No.	Capital Source		Capitalization Amount		Capitalization Percent	Cost Rate	Weighted Cost of Capital (c)	Line No.
	Actual - End of Test Period							
1	Short-Term Debt		$0		0.00%	3.95%	0.00%	1
2	Long-Term Debt - Net	(a)	$99,265	(1)	50.01%	6.49%	3.25%	2
3	Common Stock Equity	(b)	99,242		49.99%	11.00%	5.50%	3
4	Total Capital		$198,507		100.00%		8.75%	4

(1) The balance of Long-Term Debt is stated net of the unamortized balance of debt discount and issuance expense. Page 1 of Schedule D-2 provides a reconciliation between the Long-Term Debt balance of $100 million shown on Schedule E-1 and the $99.2 million balance shown above.

Supporting Schedules	Recap Schedules
(a) D-2	(c) A-3
(b) E-1	

UNS Gas, Inc.
Summary Cost of Capital
Projected Year Ended June 30, 2009
(Thousands of Dollars)

Line No.	Capital Source		Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Cost of Capital (b)	Line No.
	Projected as of June 30, 2009						
1	Short-Term Debt		$0	0.00%	3.95%	0.00%	1
2	Long-Term Debt - Net	(a)	99,430	48.41%	6.48%	3.14%	2
3	Common Stock Equity		105,959	51.59%	11.00%	5.67%	3
4	Total Capital		$205,389	100.00%		8.81%	4

Supporting Schedules
(a) D-2

Recap Schedules
(b) A-3

UNS Gas, Inc.
Cost of Long-Term Debt and Short-Term Debt
Test Year Ended June 30, 2008
(Thousands of Dollars)

Line No.	Description	End of Test Period (Actual) Outstanding	Annual Interest	Cost Rate	End of Test Period (Proposed) Outstanding	Annual Interest	Cost Rate	Line No.
	Senior Notes							
1	UNS Gas Series A	$50,000	$3,115		$50,000	$3,115		1
2	UNS Gas Series B	50,000	3,115		50,000	3,115		2
3	Total Bonds	100,000	6,230	6.23%	100,000	6,230	6.23%	3
4	Total Long-Term Debt	100,000	6,230	6.23%	100,000	6,230	6.23%	4
5	Unamortized Debt Discount, Premium and Expense and Loss on Reacquired Debt	(735)			(735)			5
6	Amortization of Debt Discount and Expense and Loss on Reacquired Debt		170			170		6
7	Credit Facility Commitment Fees		43			43		7
8	Total Long-Term Debt - Net	$99,265	$6,443	6.49%	$99,265	$6,443	6.49%	8
9	Total Short-Term Debt	N/A	N/A	N/A	N/A	N/A	N/A	9

Supporting Schedules: E-1

Recap Schedules: D-1

UNS Gas, Inc.
Cost of Long-Term Debt and Short-Term Debt
Projected Year Ended June 30, 2009
(Thousands of Dollars)

Line No.	Description	Projected Period Ended June 30, 2009 Outstanding	Annual Interest	Cost Rate	Line No.
	Senior Notes				
1	UNS Gas Series A	$50,000	$3,115		1
2	UNS Gas Series B	50,000	3,115		2
3	Total Bonds	100,000	6,230	6.23%	3
4	Total Long-Term Debt	100,000	6,230	6.23%	4
5	Unamortized Debt Discount, Premium and Expense and Loss on Reacquired Debt	(570)			5
6	Amortization of Debt Discount and Expense and Loss on Reacquired Debt		165		6
7	Credit Facility Commitment Fees		46		7
8	Total Long-Term Debt - Net	$99,430	$6,441	6.48%	8
9	Total Short-Term Debt (1)	$0	$10	3.95%	9

(1) The company projects short-term borrowings from October through December, with the outstanding balance changing from month to month.

Supporting Schedules	Recap Schedules
N/A	D-1

UNS Gas, Inc.
Cost of Preferred Stock
Test Year Ended June 30, 2008

No preferred stock was outstanding during the test year.

No preferred stock is expected to be issued.

Supporting Schedules	Recap Schedules
N/A	N/A

UNS Gas, Inc.
Cost of Common Equity
Test Year Ended June 30, 2008

The cost of common equity capital for UNS Gas, Inc. is estimated to be 11.0%.

Supporting Schedules	Recap Schedules
N/A	D-1

Schedule E

UNS Gas, Inc.
Comparative Balance Sheets
Test Year Ended June 30, 2008 and Prior Years Ended December 31, 2007 and 2006

Line No.	Description	June 30, 2008	Prior Years Ended December 31, 2007	2006	Line No.
	(a) Utility Plant				
1	Plant in Service	$340,154,214	$328,110,573	$315,049,649	1
2	Construction Work in Progress	5,496,015	9,618,275	7,199,124	2
3	Plant Held for Future Use	334,380	668,759	668,759	3
4	Southern Union Acquisition Premium	18,271,349	18,271,349	18,271,348	4
5	Citizens Acquisition Discount	(68,391,292)	(68,391,292)	(68,391,292)	5
6	Total Utility Plant	295,864,665	288,277,663	272,797,588	6
7	Accumulated Depreciation and Amortization	(93,765,398)	(89,588,999)	(86,257,832)	7
8	Accumulated Amort. - So. Union Acquisition Premium	(2,125,967)	(1,908,716)	(1,474,455)	8
9	Accumulated Amort. - Citizens Acquisition Discount	8,764,777	7,854,555	6,066,543	9
10	Total Utility Plant - Net	208,738,077	204,634,504	191,131,844	10
	Current Assets				
11	Cash and Cash Equivalents	18,573,652	19,305,288	18,692,721	11
12	Accounts Receivable - Retail Customers	7,084,598	11,774,235	17,358,928	12
13	Allowance for Doubtful Accounts	(1,219,587)	(1,010,624)	(366,736)	13
14	Accrued Unbilled Revenues	6,251,679	18,015,020	14,654,874	14
15	Intercompany Accounts Receivable	2,520,226	28,409	885,274	15
16	Material and Supplies	2,010,060	2,022,441	2,161,365	16
17	Income Tax Receivable	0	447,909	0	17
18	Deferred Income Taxes	691,662	546,333	283,816	18
19	Energy Contracts - Derivative Assets	4,058,816	13,836	0	19
20	Other	1,072,748	115,549	538,601	20
21	Total Current Assets	41,043,854	51,258,396	54,208,843	21
	Regulatory & Other Assets				
22	Regulatory Assets	1,469,815	1,494,137	1,844,766	22
23	Unamortized Debt Discount and Expense	734,726	817,096	993,227	23
24	Energy Contracts - Derivative Assets	3,480,303	67,939	0	24
25	Other	(11,932)	0	714,604	25
26	Total Deferred Debits	5,672,912	2,379,172	3,552,597	26
27	Total Assets	$255,454,843	$258,272,072	$248,893,284	27

Supporting Schedules	Recap Schedules
(a) E-5	A-4
E-9	

UNS Gas, Inc.
Comparative Balance Sheets
Test Year Ended June 30, 2008 and Prior Years Ended December 31, 2007 and 2006

Line No.	Description	June 30, 2008	Prior Years Ended December 31, 2007	2006	Line No.
	Capitalization				
1	Common Stock	$1	$1	$1	1
2	Additional Paid-In Capital	67,978,215	67,978,215	67,978,215	2
3	Accumulated Earnings	31,263,613	20,287,059	16,175,852	3
4	Total Common Stock Equity	99,241,829	88,265,275	84,154,068	4
5	Long-Term Debt	100,000,000	100,000,000	100,000,000	5
6	Total Capitalization	199,241,829	188,265,275	184,154,068	6
	Current Liabilities				
7	Under/(Over) Recovered Purchased Gas Costs	3,812,965	13,083,767	10,707,127	7
8	Accounts Payable - Net	10,342,282	20,663,810	19,799,722	8
9	Intercompany Payables - Net	1,599,282	2,150,938	1,281,155	9
10	Interest Accrued	2,374,487	2,461,655	2,454,486	10
11	Income Taxes Accrued	2,076,612	0	3,545	11
12	Other Taxes Accrued	2,609,017	4,702,527	4,873,076	12
13	Customer Deposits	2,609,271	3,090,471	3,363,760	13
14	Accrued Employee Expenses	889,217	978,871	878,041	14
15	Other Regulatory Liabilities	140,324	26,509	0	15
16	Forward Sales and Purchases Contracts	120,637	0	0	16
17	Other	239,710	129,897	151,872	17
18	Total Current Liabilities	26,813,804	47,288,446	43,512,784	18
	Deferred Credits and Other Liabilities				
19	Customer Advances for Construction	11,825,028	10,396,634	10,391,953	19
20	Accumulated Deferred Income Taxes	15,748,641	10,451,144	8,320,381	20
21	Deferred Employee Benefits	1,769,933	1,786,951	2,438,195	21
22	Other	55,607	83,622	75,903	22
23	Total Deferred Credits and Other Liabilities	29,399,209	22,718,351	21,226,432	23
24	Total Liabilities and Stockholders' Equity	$255,454,843	$258,272,072	$248,893,284	24

Supporting Schedules	Recap Schedules
E-9	A-3

UNS Gas, Inc.
Comparative Income Statements
Test Year Ended June 30, 2008 and Prior Years Ended December 31, 2007 and 2006

Line No.	Description		June 30, 2008	Prior Years Ended December 31, 2007	2006	Line No.
	(a) Operating Revenues					
1	Gas Retail Revenues		$161,759,581	$149,521,793	$160,486,195	1
2	Other Operating Revenue		1,636,425	1,430,929	1,530,313	2
3	Total Operating Revenues		163,396,006	150,952,722	162,016,508	3
	(a) Operating Expenses					
4	Purchased Gas Expenses		109,328,534	101,529,345	114,426,857	4
5	Other Operations and Maintenance Expense		24,616,335	26,848,831	24,597,503	5
6	Depreciation and Amortization		8,437,470	7,648,713	6,732,220	6
7	Taxes Other than Income Taxes		3,000,914	2,982,314	2,917,223	7
8	Income Taxes		4,428,062	2,047,765	2,626,954	8
9	Total Operating Expenses		149,811,315	141,056,968	151,300,757	9
10	Operating Income		13,584,691	9,895,754	10,715,751	10
	Total Other Income and Deductions					
11	Allowance for Equity Funds		137,755	283,907	144,703	11
12	Other - Net		241,016	618,774	241,352	12
13	Total Other Income and Deductions		378,771	902,681	386,055	13
14	Income Before Interest Expense		13,963,462	10,798,435	11,101,806	14
	Interest Expense					
15	Interest on Long Term-Debt		6,429,478	6,421,744	6,444,580	15
16	Other Interest Expense		461,598	637,434	379,174	16
17	Allowance for Borrowed Funds		(101,633)	(254,205)	(109,713)	17
18	Total Interest Expense		6,789,443	6,804,973	6,714,041	18
19	Net Income Available for Common Stock		$7,174,019	$3,993,462	$4,387,765	19
20	Earnings Per Share of Average Common Stock Outstanding	(1)	N/A	N/A	N/A	20

(1) UNS Gas, Inc. is a subsidiary of UniSource Energy Corporation and has no publicly traded stock; thus such information is not meaningful.

Supporting Schedules	Recap Schedules
(a) E-6	A-2
E-9	

UNS Gas, Inc.
Comparative Statements of Cash Flows
Test Year Ended June 30, 2008 and Prior Years Ended December 31, 2007 and 2006
(Thousands of Dollars)

Line No.	Description	June 30, 2008	Prior Years Ended December 31, 2007	2006	Line No.
	Cash Flows from Operating Activities				
1	Cash Receipts from Customers	$171,788	$165,677	$173,243	1
2	Interest Received	550	856	407	2
3	Other Cash Receipts	2,349	1,390	159	3
4	Purchased Gas Costs Paid	(113,847)	(97,137)	(97,504)	4
5	Wages Paid, Net of Amounts Capitalized	(6,999)	(7,187)	(6,847)	5
6	Payment of Other Operations and Maintenance Costs	(9,228)	(11,201)	(10,779)	6
7	Interest Paid, Net of Amounts Capitalized	(6,100)	(6,122)	(6,240)	7
8	Taxes Paid, Net of Amounts Capitalized	(17,319)	(17,115)	(17,322)	8
9	Income Taxes Paid	1,293	(43)	(2,750)	9
10	Other Cash Payments	(5,279)	(750)	(861)	10
11	Net Cash Flows from Operating Activities	17,208	28,368	31,506	11
	Cash Flows From Investing Activities				
12	Capital Expenditures	(20,012)	(22,589)	(23,404)	12
13	Other	0	506	428	13
14	Net Cash Flows from Investing Activities	(20,012)	(22,083)	(22,976)	14
	Cash Flows from Financing Activities				
15	Proceeds from Borrowings under Revolving Credit Facility	0	0	5,000	15
16	Repayment of Borrowings under Revolving Credit Facility	0	0	(5,000)	16
17	Payment of Debt Issuance Costs	0	(7)	(81)	17
18	Equity Investment from UniSource Energy Services	0	0	0	18
19	Loan from UniSource Energy	0	0	0	19
20	Repayment of Loan from UniSource Energy	0	0	0	20
21	Customer Advance Receipts	3,859	3,397	5,044	21
22	Customer Advance Refunds	(1,683)	(2,519)	(3,201)	22
23	Intercompany Advances/Repayments	(3,719)	(6,544)	(5,652)	23
24	Net Cash Flows from Financing Activities	(1,543)	(5,673)	(3,890)	24
25	Net Increase (Decrease) in Cash and Cash Equivalents	(4,347)	612	4,640	25
26	Cash and Cash Equivalents, Beginning of Period	22,921	18,693	14,053	26
27	Cash and Cash Equivalents, End of Period	$18,574	$19,305	$18,693	27

Supporting Schedules
N/A

Recap Schedules
A-5

UNS Gas, Inc.
Comparative Statements of Changes in Stockholders' Equity (Deficit)
Test Year Ended June 30, 2008 and Prior Years Ended December 31, 2007 and 2006
(Thousands of Dollars, except shares outstanding)

Line No.	Description	Common Stock Shares Outstanding	Common Stock Amount	Premium on Common Stock	Common Stock Expense	Accumulated Earnings or (Deficit)	Comprehensive Income (Loss)	Total Common Stock Equity or (Deficit)	Line No.
1	Balance, December 31, 2005	1,000	$67,978	$0	$0	$11,826	$0	$79,804	1
2	Net Income for Year					$4,388		$4,388	2
3	Dividend Declared					$0		$0	3
4	Equity in Earnings					$0		$0	4
5	Adj to Initially Recognize the Funded Status of Employee Benefit Plans						($38)	($38)	5
6	Equity Contribution from UniSource Energy Services		$0					$0	6
7	Other	0	$0					$0	7
8	Balance, December 31, 2006	1,000	$67,978	$0	$0	$16,214	($38)	$84,154	8
9	Net Income for Year					$3,994		$3,994	9
10	Dividend Declared					$0		$0	10
11	Equity in Earnings					$0		$0	11
12	Decrease in Post-Retirement Medical Liability						$68	$68	12
13	Unrealized Gain on Cash Flow Hedges						$49	$49	13
14	Equity Contribution from UniSource Energy Services		$0					$0	14
15	Other	0	$0					$0	15
16	Balance, December 31, 2007	1,000	$67,978	$0	$0	$20,208	$79	$88,265	16
17	Impact of Change in Pension Plan Measurement Date					($40)		($40)	17
18	Net Income for Six Months Ended June 30, 2008					$6,601		$6,601	18
19	Dividend Declared					$0		$0	19
20	Equity in Earnings					$0		$0	20
21	Decrease in Post-Retirement Medical Liability						$0	$0	21
22	Unrealized Gain on Cash Flow Hedges						$4,527	$4,527	22
23	Reclassification of Unrealized Gains on Cash Flow Hedges to Net Income						($111)	($111)	23
24	Equity Contribution from UniSource Energy Services		$0					$0	24
25	Other	0	$0					$0	25
26	Balance, June 30, 2008	1,000	$67,978	$0	$0	$26,769	$4,495	$99,242	26

Supporting Schedules	Recap Schedules
N/A	N/A

UNS Gas, Inc.
Detail of Gas Utility Plant - Summary Statement
Test Year Ended June 30, 2008

Line No.	Description	June 30, 2008 (a)	Net Additions (a)	December 31, 2007 (a)	Line No.
	Utility Plant in Service				
1	Intangible Plant	$1,140,492	($7,939)	$1,148,431	1
2	Transmission Plant	26,189,148	0	26,189,148	2
3	Distribution Plant	292,322,354	11,024,733	281,297,621	3
4	General Plant	20,502,221	1,026,846	19,475,374	4
5	Gross Plant in Service	340,154,214	12,043,640	328,110,573	5
6	Construction Work in Progress	5,496,015	(4,122,260)	9,618,275	6
7	Plant Held for Future Use	334,380	(334,379)	668,759	7
8	Southern Union Acquisition Premium	18,271,349	0	18,271,349	8
9	Citizens Acquisition Discount	(68,391,292)	0	(68,391,292)	9
10	Total Utility Plant	295,864,665	7,587,001	288,277,663	10
11	Accumulated Depreciation and Amortization	(93,765,398)	(4,176,399)	(89,588,999)	11
12	Accumulated Amort. - So. Union Acquisition Premium	(2,125,967)	(217,251)	(1,908,716)	12
13	Accumulated Amort. - Citizens Acquisition Discount	8,764,777	910,223	7,854,554	13
14	Total Accumulated Depreciation and Amortization	(87,126,588)	(3,483,428)	(83,643,160)	14
15	Total Net Utility Plant in Service	$208,738,077	$4,103,573	$204,634,503	15

Supporting Schedules
(a) E-5 (P2-4)

Recap Schedules
E-1

UNS Gas, Inc.
Detail of Gas Utility Plant
Test Year Ended June 30, 2008

Line No.	Acct. No.	Description	June 30, 2008	Net Additions	December 31, 2007	Line No.
		Intangible Plant				
1	302	Franchises & Consents	$362,992	($7,939)	$370,931	1
2	303	Miscellaneous Intangible Plant	777,500	0	777,500	2
3		Total Intangible Plant	1,140,492	(7,939)	1,148,431	3
		Transmission Plant				
4	365	Land & Land Rights	102,606	0	102,606	4
5	366	Structures & Improvements	16,853	0	16,853	5
6	367	Mains	22,312,011	0	22,312,011	6
7	369	Measuring and Req. Station Equipment	3,574,097	0	3,574,097	7
8	371	Other Equipment	183,581	0	183,581	8
9		Total Transmission Plant	$26,189,148	$0	$26,189,148	9
		Distribution Plant				
10	374	Land & Land Rights	257,989	0	257,989	10
11	375	Structures & Improvements	10,947	0	10,947	11
12	376	Mains	170,344,632	7,379,855	162,964,777	12
13	378	Meas. And Req. Equipment - General	2,501,503	225,461	2,276,042	13
14	379	Meas. And Req. Equipment - City Gate	3,789,758	1,358,776	2,430,982	14
15	380	Services	86,176,959	2,059,728	84,117,231	15
16	381	Meters	13,780,227	28,574	13,751,653	16
17	382	Meter Installation	8,633,492	303,477	8,330,015	17
18	383	Regulators	2,886,748	59,941	2,826,807	18
19	384	Regulator Installations	1,352,659	111,503	1,241,156	19
20	385	Industrial Measuring Equipment	1,445,920	96,569	1,349,351	20
21	387	Other Equipment	1,141,520	(599,151)	1,740,671	21
22		Total Distribution Plant	292,322,354	11,024,733	281,297,621	22
		General Plant				
23	389	Land & Land Rights	394,121	334,380	59,741	23
24	390	Structures & Improvements	5,305,943	214,482	5,091,461	24
25	391	Office Furniture & Equipment	2,084,838	12,323	2,072,515	25
26	392	Transportation Equipment	7,088,197	358,001	6,730,196	26
27	393	Stores Equipment	200,996	3,110	197,886	27
28	394	Tools, Shop & Garage Equipment	2,262,055	40,015	2,222,040	28
29	395	Laboratory Equipment	600,654	(6,791)	607,445	29
30	396	Power Operated Equipment	1,209,317	66,713	1,142,604	30
31	397	Communication Equipment	1,078,532	5,104	1,073,428	31
32	398	Miscellaneous Equipment	277,567	(491)	278,058	32
33		Total General Plant	20,502,221	1,026,846	19,475,374	33
34		Total Gas Plant in Service	$340,154,214	$12,043,640	$328,110,573	34

Supporting Schedules
N/A

Recap Schedules
E-5 (P1)

UNS Gas, Inc.
Detail of Gas Utility Plant
Test Year Ended June 30, 2008

Line No.	Acct. No.	Description	June 30, 2008	Net Additions	December 31, 2007	Line No.
		Southern Union Acquisition Premium				
		Intangible Plant				
1	302	Franchises & Consents	$20,652	$0	$20,652	1
2	303	Miscellaneous Intangible Plant	152,338	0	152,338	2
3		Total Intangible Plant	172,990	0	172,990	3
		Distribution Plant				
4	376	Mains	11,988,346	0	11,988,346	4
5	378	Meas. And Req. Equipment - General	203,438	0	203,438	5
6	379	Meas. And Req. Equipment - City Gate	266,836	0	266,836	6
7	380	Services	3,646,695	0	3,646,695	7
8	381	Meters	846,443	0	846,443	8
9	382	Meter Installation	6,102	0	6,102	9
10	383	Regulators	(109,825)	0	(109,825)	10
11	385	Industrial Measuring Equipment	272,367	0	272,367	11
12	387	Other Equipment	203,196	0	203,196	12
13		Total Distribution Plant	17,323,598	0	17,323,598	13
		General Plant				
14	389	Land and Land Rights	133,238	0	133,238	14
15	390	Structures & Improvements	173,464	0	173,464	15
16	391	Office Furniture & Equipment	21,060	0	21,060	16
17	393	Stores Equipment	26,148	0	26,148	17
18	394	Tools, Shop & Garage Equipment	434,479	0	434,479	18
19	396	Power Operated Equipment	(12,900)	0	(12,900)	19
20	398	Miscellaneous Equipment	(728)	0	(728)	20
21		Total General Plant	774,761	0	774,761	21
22		Total Southern Union Acquisition Premium	$18,271,349	$0	$18,271,349	22

Supporting Schedules
N/A

Recap Schedules
E-5 (P1)

UNS Gas, Inc.
Detail of Gas Utility Plant
Test Year Ended June 30, 2008

Line No.	Acct. No.	Description	June 30, 2008	Net Additions	December 31, 2007	Line No.
		Citizens Acquisition Discount				
		Intangible Plant				
1	302	Franchises & Consents	($81,207)	$0	($81,207)	1
2	303	Miscellaneous Intangible Plant	(80,488)	0	(80,488)	2
3		Total Intangible Plant	(161,695)	0	(161,695)	3
		Transmission Plant				
4	365	Land & Land Rights	(34,352)	0	(34,352)	4
5	366	Structures & Improvements	(5,238)	0	(5,238)	5
6	367	Mains	(3,573,586)	0	(3,573,586)	6
7	369	Measuring and Req. Station Equipment	(945,244)	0	(945,244)	7
8	371	Other Equipment	(53,866)	0	(53,866)	8
9		Total Transmission Plant	(4,612,286)	0	(4,612,286)	9
		Distribution Plant				
10	374	Land & Land Rights	(86,374)	0	(86,374)	10
11	375	Structures & Improvements	(550)	0	(550)	11
12	376	Mains	(39,243,723)	0	(39,243,723)	12
13	378	Meas. And Req. Equipment - General	(419,801)	0	(419,801)	13
14	379	Meas. And Req. Equipment - City Gate	(533,526)	0	(533,526)	14
15	380	Services	(14,788,354)	0	(14,788,354)	15
16	381	Meters	(2,585,551)	0	(2,585,551)	16
17	382	Meter Installation	(1,658,681)	0	(1,658,681)	17
18	383	Regulators	(397,969)	0	(397,969)	18
19	384	Regulator Installations	(183,202)	0	(183,202)	19
20	385	Industrial Measuring Equipment	(237,062)	0	(237,062)	20
21	387	Other Equipment	(325,252)	0	(325,252)	21
22		Total Distribution Plant	(60,460,045)	0	(60,460,045)	22
		General Plant				
23	389	Land & Land Rights	(109,571)	0	(109,571)	23
24	390	Structures & Improvements	(273,962)	0	(273,962)	24
25	391	Office Furniture & Equipment	(1,433,870)	0	(1,433,870)	25
26	392	Transportation Equipment	(190,332)	0	(190,332)	26
27	393	Stores Equipment	(39,585)	0	(39,585)	27
28	394	Tools, Shop & Garage Equipment	(513,773)	0	(513,773)	28
29	395	Laboratory Equipment	(175,657)	0	(175,657)	29
30	396	Power Operated Equipment	(12,272)	0	(12,272)	30
31	397	Communication Equipment	(342,300)	0	(342,300)	31
32	398	Miscellaneous Equipment	(65,944)	0	(65,944)	32
33		Total General Plant	(3,157,266)	0	(3,157,266)	33
34		Total Gas Plant in Service	($68,391,292)	$0	($68,391,292)	34

UNS Gas, Inc.
Comparative Departmental Operating Income Statements
Test Year Ended June 30, 2008 and Prior Years Ended December 31, 2007 and 2006

Line No.	Description	June 30, 2008	Prior Years Ended December 31, 2007	2006	Line No.
	Operating Revenues				
1	Gas Retail Revenues				1
2	Residential	$94,789,392	$90,554,693	$96,545,767	2
3	Commercial	34,814,893	33,787,924	37,573,401	3
4	Industrial	1,621,239	1,796,767	3,103,969	4
5	Lighting	116,093	107,695	129,273	5
6	Public Authorities	7,317,302	6,983,062	8,046,633	6
7	Negotiated Sales Program (NSP)	17,165,706	12,762,842	11,698,156	7
8	Black Mountain Generating Station Sales	1,993,897	0	0	8
9	Transportation	3,941,059	3,528,810	3,388,996	9
10	Total Retail Revenues	161,759,581	149,521,793	160,486,195	10
11	Other Operating Revenue	1,636,425	1,430,929	1,530,313	11
12	Total Operating Revenues	163,396,006	150,952,722	162,016,508	12
	Operating Expenses				
13	Purchased Gas Expenses (includes NSP)	109,328,534	101,529,345	114,426,857	13
14	Other Operations and Maintenance Expense	24,616,335	26,848,831	24,597,503	14
15	Depreciation and Amortization	8,437,470	7,648,713	6,732,220	15
16	Taxes Other than Income Taxes	3,000,914	2,982,314	2,917,223	16
17	Income Taxes	4,428,062	2,047,765	2,626,954	17
18	Total Operating Expenses	149,811,315	141,056,968	151,300,757	18
19	Operating Income	$13,584,691	$9,895,754	$10,715,751	19

Supporting Schedules
N/A

Recap Schedules
E-2

UNS Gas, Inc.
Gas Operating Statistics
Test Year Ended June 30, 2008 and Prior Years Ended December 31, 2007 and 2006

Line No.	Description	June 30, 2008	Prior Years Ended December 31, 2007	2006	Line No.
	Therm Sales				
1	Residential	74,201,413	71,766,226	69,805,899	1
2	Commercial	36,689,044	31,080,558	30,248,077	2
3	Industrial	1,748,826	1,950,539	2,850,638	3
4	Lighting	1,225,072	115,685	98,660	4
5	Public Authorities	8,715,424	6,744,498	6,922,088	5
6	Total	122,579,779	111,657,506	109,925,362	6
	Average Number of Customers				
7	Residential	132,347	131,786	129,054	7
8	Commercial	11,446	11,388	11,158	8
9	Industrial	23	22	20	9
10	Lighting	5	2	3	10
11	Public Authorities	4	1,071	1,069	11
12	Total	143,825	144,269	141,304	12
	Average Annual Therm Use				
13	Residential	561	545	541	13
14	Commercial	3,205	2,729	2,711	14
15	Industrial	74,950	88,661	142,532	15
16	Lighting	245,014	57,843	32,887	16
17	Public Authorities	2,178,856	6,297	6,475	17
18	Total	852	774	778	18

Note:
The above statistics exclude the Negotiated Sales Program (NSP) and Transportation. The following data summarizes NSP and Transportation statistics:

Transportation (includes T2-Valencia & excludes BMGS)			
Therm Sales	20,585,885	25,370,429	23,198,385
Average Number of Customers	1,091 (1)	23	23
Average Annual Therm Use	18,864	1,103,062	1,008,625
NSP			
Therm Sales	21,587,368	19,093,737	17,059,932
Average Number of Customers	14	14	14
Average Annual Therm Use	1,541,955	1,363,838	1,218,567

(1) The transportation customer count for the test year ended June 30, 2008 is larger than the prior years due to a change to counting meters instead of customers for ratemaking.

Supporting Schedules	Recap Schedules
N/A	N/A

UNS Gas, Inc.
Taxes Charged to Operations
Test Year Ended June 30, 2008 and Prior Years Ended December 31, 2007 and 2006

Line No.	Description	June 30, 2008	Prior Years Ended December 31, 2007	2006	Line No.
	Federal Taxes				
1	Income	$1,009,585	$361,250	$3,261,203	1
2	Unemployment	9,526	10,086	10,053	2
3	FICA	537,474	549,481	518,061	3
4	Deferred Income Taxes	2,641,885	1,295,169	(1,097,254)	4
5	*Total*	4,198,470	2,215,986	2,692,063	5
	State Taxes				
6	Income	425,913	(7,735)	597,042	6
7	Unemployment	11,182	14,522	15,787	7
8	Premium Receipts Tax	0	0	0	8
9	Real and Personal Property	0	0	0	9
10	Deferred Income Taxes	350,680	399,081	(134,036)	10
11	Total	787,775	405,868	478,793	11
	Local Taxes				
12	Income	0	0	0	12
13	Real and Personal Property	2,256,005	2,312,985	2,270,573	13
14	Indian Tribal Taxes - PIT and BAT	0	0	0	14
15	Other	186,728	165,890	102,748	15
16	Total	2,442,733	2,478,875	2,373,321	16
17	Total Taxes Charged to Operating Expenses	$7,428,978	$5,100,729	$5,544,177	17

Note: Taxes and assessments related to sales of energy are not included in revenues or other tax expense categories.

Supporting Schedules	Recap Schedules
N/A	E-2

UNS Gas, Inc.
Test Year Ended June 30, 2008
Notes to Financial Statements

The UNS Gas, Inc. Audited Financials as of December 31, 2007, which are confidential, will be provided when the Protective Agreement for this rate proceeding has been executed.

Supporting Schedules
N/A

Recap Schedules
N/A

Schedule F

UNS Gas, Inc.
Income Statement - Test Year Ended June 30, 2008 and
Projected Year Ended June 30, 2009 at Present and Proposed Rates
(Thousands of Dollars Except Return on Average Common Equity)

Line No.	Description		Test Year Ended June 30, 2008 (a)	Projected Year Ended June 30, 2009 Present Rates	Projected Year Ended June 30, 2009 Proposed Rates	Line No.
1	Operating Revenues		$163,396	$193,031	$202,907	1
	Operating Expenses					
2	Purchased Gas		109,329	136,213	136,213	2
3	Other Operations and Maintenance Expense		24,616	29,178	29,178	3
4	Depreciation and Amortization		8,437	7,338	7,338	4
5	Taxes Other than Income Taxes		3,001	3,186	3,186	5
6	Total Operating Expenses		145,383	175,915	175,915	6
7	Pre-Tax Operating Income		18,013	17,116	26,992	7
	Other Income and Deductions					
8	Allowance for Equity Funds		138	197	197	8
9	Other - Net		241	164	241	9
10	Total Other Income and Deductions		379	361	438	10
11	Income Before Interest Expense		18,392	17,477	27,430	11
	Interest Expense					
12	Interest on Long-Term Debt		6,429	6,223	6,223	12
13	Other Interest Expense		462	274	266	13
14	Allowance for Borrowed Funds		(102)	(144)	(144)	14
15	Total Interest Expense		6,789	6,353	6,345	15
16	Income Before Income Tax Expense		11,603	11,124	21,085	16
17	Income Tax Expense		4,428	4,409	8,351	17
18	Net Income Available for Common Stock		$7,175	$6,715	$12,734	18
19	Earnings Per Share of Average Common Stock Outstanding	(1)	N/A	N/A	N/A	19
20	Return on Average Common Equity		7.68%	6.54%	12.06%	20

(1) UNS Gas, Inc. is a subsidiary of UniSource Energy Corporation and has no publicly traded stock; thus such information is not meaningful.

Supporting Schedules	Recap Schedules
(a) E-2	A-2

UNS Gas, Inc.
Statement of Cash Flows - Test Year Ended June 30, 2008 and
Projected Year Ended June 30, 2009 at Present and Proposed Rates
(Thousands of Dollars)

Line No.	Description	Test Year Ended June 30, 2008 (a)	Projected Year Ended June 30, 2009 Present Rates	Projected Year Ended June 30, 2009 Proposed Rates	Line No.
	Cash Flows from Operating Activities				
1	Cash Receipts from Customers	$171,788	$204,515	$214,528	1
2	Other Cash Receipts	$550	1,905	1,905	2
3	Purchased Gas Costs Paid	$2,349	(137,073)	(137,073)	3
4	Payment of Other Operations and Maintenance Costs	($120,846)	(28,136)	(28,136)	4
5	Interest Paid, Net of Amounts Capitalized	($9,228)	(6,388)	(6,381)	5
6	Taxes Paid, Net of Amounts Capitalized	($17,319)	(15,283)	(15,890)	6
7	Income Taxes Paid	$1,293	(3,025)	(4,797)	7
8	Other Cash Payments	($11,379)	(58)	19	8
9	Net Cash Flows from Operating Activities	17,208	16,457	24,175	9
	Cash Flows from Investing Activities				
10	Capital Expenditures	(20,012)	(25,650)	(25,650)	10
11	Other	0	0	0	11
12	Net Cash Flows from Investing Activities	(20,012)	(25,650)	(25,650)	12
	Cash Flow from Financing Activities				
13	Payment of Debt Issuance Costs	0	0	0	13
14	Borrowing under Revolving Credit Facility	0	1	0	14
15	Other	(1,543)	(1,110)	(1,110)	15
16	Net Cash Flows from Financing Activities	(1,543)	(1,109)	(1,110)	16
17	Net Increase (Decrease) in Cash	($4,347)	($10,302)	($2,585)	17

Supporting Schedule
(a) E-3

Recap Schedules
A-5

UNS Gas, Inc.
Projected Construction Requirements
Test Year Ended June 30, 2008 and Projected Years 2009 through 2011
(Thousands of Dollars)

Line No.	Description	Test Year Ended June 30, 2008 (a), (b)	Projected Year Ended December 31, 2009 (a), (b)	2010 (a)	2011 (a)	Total 2009-2011	Line No.
1	Transmission Plant	0	0	0	0	0	1
2	Distribution Plant	17,980	22,039	18,127	20,342	60,508	2
3	General Plant	2,032	1,208	2,020	2,109	5,337	3
4	Total Construction Expenditures	$20,012	$23,247	$20,147	$22,451	$65,845	4

Supporting Schedules
N/A

Recap Schedules
(a) A-4
(b) F-2

UNS Gas, Inc.
Key Assumptions Used in Preparing Forecasts

Customer Growth and Sales
Retail customer growth is forecasted to be 1.5% in 2009.
Retail sales growth is forecasted to be (0.1)% in 2009. (On a weather-normalized basis, retail sales growth is expected to be 1.8% in 2009).

Purchased Gas Costs
Natural gas costs are forecasted using forward market projections and completed hedging transactions as of August 29, 2008.
PGA pricing and gas cost recovery are based on the PGA mechanism in effect as of September 2008, with pricing adjustments from January 2009 - December 2009 to bring the 2009 Regulatory PGA Bank balance to zero.

Operations and Maintenance Expenses
O&M Expenses for 2009 are based on the operating budget approved in December 2007, with the adjustments for DSM expenses and vehicle depreciation.

Construction Expenditures
Construction expenditures for 2009 are based on the capital budget approved in December 2007, net of forecasted CIAC.

Interest Rate Assumptions
The interest rate on temporary investments is forecasted at 2.95% in 2009.
The interest rate on short-term borrowing is forecasted at 4.45% in 2009.

Capital Structure Changes
The balance of common equity is forecasted to grow in 2009 due to continued retention of earnings (no dividend is assumed).
External financing needs are assumed to be met with borrowings under the UNS Gas revolving credit facility.

Schedule G

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	SUMMARY AT PRESENT RATES								
2									
3	DEVELOPMENT OF RATE BASE								
4	GAS PLANT IN SERVICE		$287,517,886	$200,012,920	$48,453,782	$22,977,931	$15,852,403	$142,389	$78,461
5	DEPREC & AMORT RESERVE		83,607,897	59,928,398	13,322,554	6,091,962	4,207,753	36,698	20,532
6	NET PLANT IN SERVICE		203,909,989	140,084,522	35,131,228	16,885,969	11,644,650	105,691	57,929
7									
8	ADDITIONS & DEDUCTIONS								
9	CASH WORKING CAPITAL		1,568	1,091	264	125	86	1	0
10	MATERIALS & SUPPIES		2,010,788	1,398,813	338,867	160,699	110,866	996	549
11	PREPAYMENTS		352,564	245,263	59,416	28,176	19,439	175	96
12	CUSTOMER ADVANCES FOR CONSTRUCTION		(11,235,876)	(7,816,280)	(1,893,519)	(897,952)	(619,494)	(5,564)	(3,066)
13	CUSTOMER DEPOSITS		(2,609,271)	(1,815,149)	(439,726)	(208,528)	(143,863)	(1,292)	(712)
14	OTHER		470,218	234,806	120,940	47,947	42,854	4,282	19,388
15	ACCUM DEFERRED INCOME TAXES		(10,606,875)	(7,378,713)	(1,787,517)	(847,683)	(584,814)	(5,253)	(2,895)
16	TOTAL ADDITIONS & DEDUCTIONS		(21,616,884)	(15,130,171)	(3,601,275)	(1,717,216)	(1,174,926)	(6,656)	13,361
17									
18	TOTAL RATE BASE		$182,293,105	$124,954,351	$31,529,953	$15,168,753	$10,469,724	$99,034	$71,290
19									
20	DEVELOPMENT OF RETURN								
21	OPERATING REVENUES								
22	SALES OF GAS TO ULTIMATE CUST		51,157,764	36,381,453	10,351,444	1,888,724	2,435,339	66,940	33,865
23	OTHER OPERATING REVENUES		1,744,743	1,525,144	146,391	40,350	30,336	633	1,889
24	TOTAL GAS OPERATING REVENUES		52,902,507	37,906,597	10,497,835	1,929,075	2,465,675	67,573	35,753
25									
26	OPERATING EXPENSES								
27	OPER & MAINT EXPENSE		25,116,748	19,979,779	3,290,835	1,007,825	802,622	12,181	23,504
28	AMORTIZATION & DEPRECIATION EXP		8,240,005	6,043,745	1,262,380	542,363	386,207	3,393	1,917
29	TAXES OTHER THAN INCOME		4,342,079	3,076,211	709,027	326,518	227,175	2,024	1,124
30	TAX EXPENSE		3,603,671	1,849,989	1,624,236	(165,950)	274,754	17,980	2,662
31	TOTAL OPERATING EXPENSES		41,302,503	30,949,724	6,886,478	1,710,756	1,690,758	35,579	29,207
32									
33	OPERATING INCOME		$11,600,005	$6,956,873	$3,611,357	$218,318	$774,916	$31,994	$6,546
34									
35	RATE OF RETURN		6.36%	5.57%	11.45%	1.44%	7.40%	32.31%	9.18%
36	INDEX RATE OF RETURN		1.000	0.875	1.800	0.226	1.163	5.077	1.443
37									
38									
39									
40									
41									
42									
43									
44									
45									

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	SUMMARY AT PRESENT RATES							
2								
3	DEVELOPMENT OF RATE BASE							
4	GAS PLANT IN SERVICE		$43,443,335	$5,010,447	$1,031,030	$21,946,902	$8,159,970	$7,692,433
5	DEPREC & AMORT RESERVE		11,919,046	1,403,507	346,354	5,745,608	2,169,321	2,038,433
6	NET PLANT IN SERVICE		31,524,289	3,606,939	684,675	16,201,293	5,990,649	5,654,000
7								
8	ADDITIONS & DEDUCTIONS							
9	CASH WORKING CAPITAL		237	27	6	120	45	42
10	MATERIALS & SUPPIES		303,826	35,041	7,211	153,488	57,068	53,798
11	PREPAYMENTS		53,272	6,144	1,264	26,912	10,006	9,433
12	CUSTOMER ADVANCES FOR CONSTRUCTION		(1,697,717)	(195,803)	(40,291)	(857,660)	(318,882)	(300,612)
13	CUSTOMER DEPOSITS		(394,255)	(45,471)	(9,357)	(199,172)	(74,053)	(69,810)
14	OTHER		105,211	15,729	1,989	45,958	18,561	24,293
15	ACCUM DEFERRED INCOME TAXES		(1,602,676)	(184,841)	(38,036)	(809,647)	(301,031)	(283,783)
16	TOTAL ADDITIONS & DEDUCTIONS		(3,232,102)	(369,173)	(77,215)	(1,640,001)	(608,287)	(566,639)
17								
18	TOTAL RATE BASE		$28,292,187	$3,237,766	$607,461	$14,561,293	$5,382,362	$5,087,362
19								
20	DEVELOPMENT OF RETURN							
21	OPERATING REVENUES							
22	SALES OF GAS TO ULTIMATE CUST		9,571,509	779,934	133,707	1,755,017	1,630,262	805,077
23	OTHER OPERATING REVENUES		137,318	9,073	2,119	38,231	16,700	13,636
24	TOTAL GAS OPERATING REVENUES		9,708,828	789,007	135,827	1,793,248	1,646,961	818,713
25								
26	OPERATING EXPENSES							
27	OPER & MAINT EXPENSE		3,047,425	243,411	33,475	974,351	456,349	346,273
28	AMORTIZATION & DEPRECIATION EXP		1,145,232	117,148	21,305	521,058	204,325	181,882
29	TAXES OTHER THAN INCOME		637,615	71,411	14,406	312,113	117,790	109,385
30	TAX EXPENSE		1,526,814	97,422	18,146	(184,096)	267,568	7,185
31	TOTAL OPERATING EXPENSES		6,357,086	529,392	87,331	1,623,425	1,046,033	644,726
32								
33	OPERATING INCOME		$3,351,742	$259,615	$48,496	$169,822	$600,929	$173,988
34								
35	RATE OF RETURN		11.85%	8.02%	7.98%	1.17%	11.16%	3.42%
36	INDEX RATE OF RETURN		1.862	1.260	1.255	0.183	1.755	0.537
37								
38								
39								
40								
41								
42								
43								
44								
45								

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	SUMMARY AT PRESENT RATES						
2							
3	DEVELOPMENT OF RATE BASE						
4	GAS PLANT IN SERVICE		$189,665,466	$10,347,454	$43,443,335	$1,831,735	$3,178,712
5	DEPREC & AMORT RESERVE		56,812,438	3,115,959	11,919,046	535,343	868,165
6	NET PLANT IN SERVICE		132,853,027	7,231,495	31,524,289	1,296,392	2,310,547
7							
8	ADDITIONS & DEDUCTIONS						
9	CASH WORKING CAPITAL		1,034	56	237	10	17
10	MATERIALS & SUPPIES		1,326,447	72,366	303,826	12,810	22,231
11	PREPAYMENTS		232,574	12,688	53,272	2,246	3,898
12	CUSTOMER ADVANCES FOR CONSTRUCTION		(7,411,913)	(404,367)	(1,697,717)	(71,582)	(124,220)
13	CUSTOMER DEPOSITS		(1,721,245)	(93,905)	(394,255)	(16,623)	(28,847)
14	OTHER		223,269	11,537	105,211	4,807	10,922
15	ACCUM DEFERRED INCOME TAXES		(6,996,983)	(381,730)	(1,602,676)	(67,575)	(117,266)
16	TOTAL ADDITIONS & DEDUCTIONS		(14,346,817)	(783,354)	(3,232,102)	(135,907)	(233,266)
17							
18	TOTAL RATE BASE		$118,506,210	$6,448,141	$28,292,187	$1,160,485	$2,077,281
19							
20	DEVELOPMENT OF RETURN						
21	OPERATING REVENUES						
22	SALES OF GAS TO ULTIMATE CUST		35,003,749	1,377,705	9,571,509	246,710	533,224
23	OTHER OPERATING REVENUES		1,444,139	81,005	137,318	3,593	5,480
24	TOTAL GAS OPERATING REVENUES		36,447,887	1,458,710	9,708,828	250,303	538,704
25							
26	OPERATING EXPENSES						
27	OPER & MAINT EXPENSE		18,951,733	1,028,046	3,047,425	84,990	158,421
28	AMORTIZATION & DEPRECIATION EXP		5,728,693	315,051	1,145,232	42,422	74,727
29	TAXES OTHER THAN INCOME		2,916,631	159,579	637,615	26,142	45,269
30	TAX EXPENSE		1,945,972	(95,983)	1,526,814	22,926	74,496
31	TOTAL OPERATING EXPENSES		29,543,030	1,406,695	6,357,086	176,479	352,913
32							
33	OPERATING INCOME		$6,904,858	$52,015	$3,351,742	$73,824	$185,791
34							
35	RATE OF RETURN		5.83%	0.81%	11.85%	6.36%	8.94%
36	INDEX RATE OF RETURN		0.92	0.13	1.86	1.00	1.41
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	SUMMARY AT PRESENT RATES				
2					
3	DEVELOPMENT OF RATE BASE				
4	GAS PLANT IN SERVICE		$1,031,030	$1,343,714	$20,603,188
5	DEPREC & AMORT RESERVE		346,354	368,902	5,376,706
6	NET PLANT IN SERVICE		684,675	974,812	15,226,481
7					
8	ADDITIONS & DEDUCTIONS				
9	CASH WORKING CAPITAL		6	7	112
10	MATERIALS & SUPPIES		7,211	9,397	144,091
11	PREPAYMENTS		1,264	1,648	25,264
12	CUSTOMER ADVANCES FOR CONSTRUCTION		(40,291)	(52,511)	(805,149)
13	CUSTOMER DEPOSITS		(9,357)	(12,194)	(186,977)
14	OTHER		1,989	4,356	41,603
15	ACCUM DEFERRED INCOME TAXES		(38,036)	(49,571)	(760,076)
16	TOTAL ADDITIONS & DEDUCTIONS		(77,215)	(98,868)	(1,541,133)
17					
18	TOTAL RATE BASE		$607,461	$875,944	$13,685,349
19					
20	DEVELOPMENT OF RETURN				
21	OPERATING REVENUES				
22	SALES OF GAS TO ULTIMATE CUST		133,707	121,445	1,633,572
23	OTHER OPERATING REVENUES		2,119	2,711	35,521
24	TOTAL GAS OPERATING REVENUES		135,827	124,155	1,669,093
25					
26	OPERATING EXPENSES				
27	OPER & MAINT EXPENSE		33,475	56,760	917,590
28	AMORTIZATION & DEPRECIATION EXP		21,305	31,577	489,481
29	TAXES OTHER THAN INCOME		14,406	19,137	292,975
30	TAX EXPENSE		18,146	(4,338)	(179,758)
31	TOTAL OPERATING EXPENSES		87,331	103,137	1,520,289
32					
33	OPERATING INCOME		$48,496	$21,018	$148,804
34					
35	RATE OF RETURN		7.98%	2.40%	1.09%
36	INDEX RATE OF RETURN		1.25	0.38	0.17
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	SUMMARY AT PRESENT RATES						
2							
3	DEVELOPMENT OF RATE BASE						
4	GAS PLANT IN SERVICE		$8,159,970	$1,534,126	$6,158,307	$142,389	$78,461
5	DEPREC & AMORT RESERVE		2,169,321	415,541	1,622,891	36,698	20,532
6	NET PLANT IN SERVICE		5,990,649	1,118,585	4,535,416	105,691	57,929
7							
8	ADDITIONS & DEDUCTIONS						
9	CASH WORKING CAPITAL		45	8	34	1	0
10	MATERIALS & SUPPIES		57,068	10,729	43,069	996	549
11	PREPAYMENTS		10,006	1,881	7,552	175	96
12	CUSTOMER ADVANCES FOR CONSTRUCTION		(318,882)	(59,952)	(240,660)	(5,564)	(3,066)
13	CUSTOMER DEPOSITS		(74,053)	(13,922)	(55,888)	(1,292)	(712)
14	OTHER		18,561	4,135	20,159	4,282	19,388
15	ACCUM DEFERRED INCOME TAXES		(301,031)	(56,596)	(227,187)	(5,253)	(2,895)
16	TOTAL ADDITIONS & DEDUCTIONS		(608,287)	(113,717)	(452,922)	(6,656)	13,361
17							
18	TOTAL RATE BASE		$5,382,362	$1,004,868	$4,082,494	$99,034	$71,290
19							
20	DEVELOPMENT OF RETURN						
21	OPERATING REVENUES						
22	SALES OF GAS TO ULTIMATE CUST		1,630,262	148,817	656,260	66,940	33,865
23	OTHER OPERATING REVENUES		16,700	3,019	10,617	633	1,889
24	TOTAL GAS OPERATING REVENUES		1,646,961	151,836	666,877	67,573	35,753
25							
26	OPERATING EXPENSES						
27	OPER & MAINT EXPENSE		456,349	60,353	285,920	12,181	23,504
28	AMORTIZATION & DEPRECIATION EXP		204,325	35,733	146,149	3,393	1,917
29	TAXES OTHER THAN INCOME		117,790	21,744	87,641	2,024	1,124
30	TAX EXPENSE		267,568	736	6,450	17,980	2,662
31	TOTAL OPERATING EXPENSES		1,046,033	118,565	526,160	35,579	29,207
32							
33	OPERATING INCOME		$600,929	$33,271	$140,717	$31,994	$6,546
34							
35	RATE OF RETURN		11.16%	3.31%	3.45%	32.31%	9.18%
36	INDEX RATE OF RETURN		1.75	0.52	0.54	5.08	1.44
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	EQUALIZED RETURN AT PROPOSED ROR								
2									
3	UNADJUSTED RATE BASE		$182,293,105	$124,954,351	$31,529,953	$15,168,753	$10,469,724	$99,034	$71,290
4	CHANGE IN WC - PLANT	PLANT	0	0	0	0	0	0	0
5	CHANGE IN WC - COMMODITY	WCGC	0	0	0	0	0	0	0
6	CHANGE IN WC - O&M	WCOTH	0	0	0	0	0	0	0
7	ADJUSTED RATE BASE		182,293,105	124,954,351	31,529,953	15,168,753	10,469,724	99,034	71,290
8	RATE OF RETURN ON RATE BASE		9.54%	9.54%	9.54%	9.54%	9.54%	9.54%	9.54%
9	RETURN		17,393,036	11,922,203	3,008,351	1,447,288	998,942	9,449	6,802
10									
11	OPERATING EXPENSES								
12	PRESENT OPER & MAINT EXPENSE		25,116,748	19,979,779	3,290,835	1,007,825	802,622	12,181	23,504
13	CHANGE IN GAS COSTS	GASSALES	0	0	0	0	0	0	0
14	INCREASE IN UNCOLLECTIBLES	REVCHGC	0	0	0	0	0	0	0
15	TOTAL O&M AT PROPOSED		25,116,748	19,979,779	3,290,835	1,007,825	802,622	12,181	23,504
16	AMORTIZATION & DEPRECIATION EXP		8,240,005	6,043,745	1,262,380	542,363	386,207	3,393	1,917
17	TAXES OTHER THAN INCOME		4,342,079	3,076,211	709,027	326,518	227,175	2,024	1,124
18	TAX EXPENSE		7,291,517	5,032,091	1,255,785	584,979	411,639	4,205	2,819
19	TOTAL OPERATING EXPENSES		44,990,348	34,131,826	6,518,027	2,461,685	1,827,643	21,803	29,364
20									
21	COST OF SERVICE		$62,383,384	$46,054,029	$9,526,378	$3,908,973	$2,826,586	$31,252	$36,166
22									
23	PROPOSED REVENUE @ EQUALIZED ROR								
24	FIRM SALES OF GAS		60,638,641	44,503,160	9,357,489	3,904,239	2,808,179	31,233	34,341
25	INTERR SALES GAS COST REV	GASSALES	0	0	0	0	0	0	0
26	INTERR SALES PROFIT MARGINS	DEMGAS	0	0	0	0	0	0	0
27	INTERRUPTIBLE TRANSPORTATION	DISTR	0	0	0	0	0	0	0
28	SALES FOR RESALE	DEMGAS	0	0	0	0	0	0	0
29	TOTAL SALES OF GAS		60,638,641	44,503,160	9,357,489	3,904,239	2,808,179	31,233	34,341
30									
31	OTHER OPERATING REVENUES								
32	FORFEITED DISCOUNTS	FORFDISC	495,690	367,395	109,583	1,538	15,360	0	1,814
33	MISCELLANEOUS SERVICE REV	CUST487B	1,211,079	1,157,058	52,906	162	953	0	0
34	OTHER REVENUE	PLANT	37,974	26,417	6,400	3,035	2,094	19	10
35	OTHER REVENUE	PLANT	0	0	0	0	0	0	0
36	OTHER REVENUE	PLANT	0	0	0	0	0	0	0
37	TOTAL OTHER OPERATING REV		1,744,743	1,550,869	168,889	4,734	18,407	19	1,825
38									
39	TOTAL PROPOSED REVENUE @ EQUALIZED ROR		$62,383,384	$46,054,029	$9,526,378	$3,908,973	$2,826,586	$31,252	$36,166
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	EQUALIZED RETURN AT PROPOSED ROR							
2								
3	UNADJUSTED RATE BASE		$28,292,187	$3,237,766	$607,461	$14,561,293	$5,382,362	$5,087,362
4	CHANGE IN WC - PLANT	PLANT	0	0	0	0	0	0
5	CHANGE IN WC - COMMODITY	WCGC	0	0	0	0	0	0
6	CHANGE IN WC - O&M	WCOTH	0	0	0	0	0	0
7	ADJUSTED RATE BASE		28,292,187	3,237,766	607,461	14,561,293	5,382,362	5,087,362
8	RATE OF RETURN ON RATE BASE		9.54%	9.54%	9.54%	9.54%	9.54%	9.54%
9	RETURN		2,699,427	308,923	57,959	1,389,329	513,544	485,398
10								
11	OPERATING EXPENSES							
12	PRESENT OPER & MAINT EXPENSE		3,047,425	243,411	33,475	974,351	456,349	346,273
13	CHANGE IN GAS COSTS	GASSALES	0	0	0	0	0	0
14	INCREASE IN UNCOLLECTIBLES	REVCHGC	0	0	0	0	0	0
15	TOTAL O&M AT PROPOSED		3,047,425	243,411	33,475	974,351	456,349	346,273
16	AMORTIZATION & DEPRECIATION EXP		1,145,232	117,148	21,305	521,058	204,325	181,882
17	TAXES OTHER THAN INCOME		637,615	71,411	14,406	312,113	117,790	109,385
18	TAX EXPENSE		1,128,235	127,550	23,928	561,051	214,174	197,464
19	TOTAL OPERATING EXPENSES		5,958,506	559,521	93,113	2,368,572	992,639	835,004
20								
21	COST OF SERVICE		$8,657,934	$868,444	$151,073	$3,757,901	$1,506,183	$1,320,402
22								
23	PROPOSED REVENUE @ EQUALIZED ROR							
24	FIRM SALES OF GAS		8,490,377	867,112	150,069	3,754,170	1,488,864	1,319,314
25	INTERR SALES GAS COST REV	GASSALES	0	0	0	0	0	0
26	INTERR SALES PROFIT MARGINS	DEMGAS	0	0	0	0	0	0
27	INTERRUPTIBLE TRANSPORTATION	DISTR	0	0	0	0	0	0
28	SALES FOR RESALE	DEMGAS	0	0	0	0	0	0
29	TOTAL SALES OF GAS		8,490,377	867,112	150,069	3,754,170	1,488,864	1,319,314
30								
31	OTHER OPERATING REVENUES							
32	FORFEITED DISCOUNTS	FORFDISC	108,913	670	706	832	15,288	72
33	MISCELLANEOUS SERVICE REV	CUST487B	52,906	0	162	0	953	0
34	OTHER REVENUE	PLANT	5,738	662	136	2,899	1,078	1,016
35	OTHER REVENUE	PLANT	0	0	0	0	0	0
36	OTHER REVENUE	PLANT	0	0	0	0	0	0
37	TOTAL OTHER OPERATING REV		167,557	1,332	1,004	3,731	17,319	1,088
38								
39	TOTAL PROPOSED REVENUE @ EQUALIZED ROR		$8,657,934	$868,444	$151,073	$3,757,901	$1,506,183	$1,320,402
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	EQUALIZED RETURN AT PROPOSED ROR						
2							
3	UNADJUSTED RATE BASE		$118,506,210	$6,448,141	$28,292,187	$1,160,485	$2,077,281
4	CHANGE IN WC - PLANT	PLANT	0	0	0	0	0
5	CHANGE IN WC - COMMODITY	WCGC	0	0	0	0	0
6	CHANGE IN WC - O&M	WCOTH	0	0	0	0	0
7	ADJUSTED RATE BASE		118,506,210	6,448,141	28,292,187	1,160,485	2,077,281
8	RATE OF RETURN ON RATE BASE		0.0954	0.0954	0.0954	0.0954	0.0954
9	RETURN		11,306,970	615,233	2,699,427	110,725	198,199
10							
11	OPERATING EXPENSES						
12	PRESENT OPER & MAINT EXPENSE		18,951,733	1,028,046	3,047,425	84,990	158,421
13	CHANGE IN GAS COSTS	GASSALES	0	0	0	0	0
14	INCREASE IN UNCOLLECTIBLES	REVCHGC	0	0	0	0	0
15	TOTAL O&M AT PROPOSED		18,951,733	1,028,046	3,047,425	84,990	158,421
16	AMORTIZATION & DEPRECIATION EXP		5,728,693	315,051	1,145,232	42,422	74,727
17	TAXES OTHER THAN INCOME		2,916,631	159,579	637,615	26,142	45,269
18	TAX EXPENSE		4,783,934.6	248,156	1,128,235	45,473	82,077
19	TOTAL OPERATING EXPENSES		32,380,992	1,750,833	5,958,506	199,026	360,494
20							
21	COST OF SERVICE		$43,687,963	$2,366,066	$8,657,934	$309,751	$558,693
22							
23	PROPOSED REVENUE @ EQUALIZED ROR						
24	FIRM SALES OF GAS		42,220,170	2,282,989	8,490,377	309,375	557,737
25	INTERR SALES GAS COST REV	GASSALES	0	0	0	0	0
26	INTERR SALES PROFIT MARGINS	DEMGAS	0	0	0	0	0
27	INTERRUPTIBLE TRANSPORTATION	DISTR	0	0	0	0	0
28	SALES FOR RESALE	DEMGAS	0	0	0	0	0
29	TOTAL SALES OF GAS		42,220,170	2,282,989	8,490,377	309,375	557,737
30							
31	OTHER OPERATING REVENUES						
32	FORFEITED DISCOUNTS	FORFDISC	347,702	19,692	108,913	134	536
33	MISCELLANEOUS SERVICE REV	CUST487B	1,095,040	62,018	52,906	0	0
34	OTHER REVENUE	PLANT	25,050	1,367	5,738	242	420
35	OTHER REVENUE	PLANT	0	0	0	0	0
36	OTHER REVENUE	PLANT	0	0	0	0	0
37	TOTAL OTHER OPERATING REV		1,467,792	83,077	167,557	376	956
38							
39	TOTAL PROPOSED REVENUE @ EQUALIZED ROR		$43,687,963	$2,366,066	$8,657,934	$309,751	$558,693
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	EQUALIZED RETURN AT PROPOSED ROR				
2					
3	UNADJUSTED RATE BASE		$607,461	$875,944	$13,685,349
4	CHANGE IN WC - PLANT	PLANT	0	0	0
5	CHANGE IN WC - COMMODITY	WCGC	0	0	0
6	CHANGE IN WC - O&M	WCOTH	0	0	0
7	ADJUSTED RATE BASE		607,461	875,944	13,685,349
8	RATE OF RETURN ON RATE BASE		0.0954	0.0954	0.0954
9	RETURN		57,959	83,576	1,305,753
10					
11	OPERATING EXPENSES				
12	PRESENT OPER & MAINT EXPENSE		33,475	56,760	917,590
13	CHANGE IN GAS COSTS	GASSALES	0	0	0
14	INCREASE IN UNCOLLECTIBLES	REVCHGC	0	0	0
15	TOTAL O&M AT PROPOSED		33,475	56,760	917,590
16	AMORTIZATION & DEPRECIATION EXP		21,305	31,577	489,481
17	TAXES OTHER THAN INCOME		14,406	19,137	292,975
18	TAX EXPENSE		23,928	33,887	527,164
19	TOTAL OPERATING EXPENSES		93,113	141,361	2,227,211
20					
21	COST OF SERVICE		$151,073	$224,937	$3,532,964
22					
23	PROPOSED REVENUE @ EQUALIZED ROR				
24	FIRM SALES OF GAS		150,069	224,583	3,529,587
25	INTERR SALES GAS COST REV	GASSALES	0	0	0
26	INTERR SALES PROFIT MARGINS	DEMGAS	0	0	0
27	INTERRUPTIBLE TRANSPORTATION	DISTR	0	0	0
28	SALES FOR RESALE	DEMGAS	0	0	0
29	TOTAL SALES OF GAS		150,069	224,583	3,529,587
30					
31	OTHER OPERATING REVENUES				
32	FORFEITED DISCOUNTS	FORFDISC	706	176	655
33	MISCELLANEOUS SERVICE REV	CUST487B	162	0	0
34	OTHER REVENUE	PLANT	136	177	2,721
35	OTHER REVENUE	PLANT	0	0	0
36	OTHER REVENUE	PLANT	0	0	0
37	TOTAL OTHER OPERATING REV		1,004	354	3,377
38					
39	TOTAL PROPOSED REVENUE @ EQUALIZED ROR		$151,073	$224,937	$3,532,964
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	EQUALIZED RETURN AT PROPOSED ROR						
2							
3	UNADJUSTED RATE BASE		$5,382,362	$1,004,868	$4,082,494	$99,034	$71,290
4	CHANGE IN WC - PLANT	PLANT	0	0	0	0	0
5	CHANGE IN WC - COMMODITY	WCGC	0	0	0	0	0
6	CHANGE IN WC - O&M	WCOTH	0	0	0	0	0
7	ADJUSTED RATE BASE		5,382,362	1,004,868	4,082,494	99,034	71,290
8	RATE OF RETURN ON RATE BASE		0.0954	0.0954	0.0954	0.0954	0.0954
9	RETURN		513,544	95,877	389,521	9,449	6,802
10							
11	OPERATING EXPENSES						
12	PRESENT OPER & MAINT EXPENSE		456,349	60,353	285,920	12,181	23,504
13	CHANGE IN GAS COSTS	GASSALES	0	0	0	0	0
14	INCREASE IN UNCOLLECTIBLES	REVCHGC	0	0	0	0	0
15	TOTAL O&M AT PROPOSED		456,349	60,353	285,920	12,181	23,504
16	AMORTIZATION & DEPRECIATION EXP		204,325	35,733	146,149	3,393	1,917
17	TAXES OTHER THAN INCOME		117,790	21,744	87,641	2,024	1,124
18	TAX EXPENSE		214,174	38,990	158,474	4,205	2,819
19	TOTAL OPERATING EXPENSES		992,639	156,819	678,185	21,803	29,364
20							
21	COST OF SERVICE		$1,506,183	$252,696	$1,067,706	$31,252	$36,166
22							
23	PROPOSED REVENUE @ EQUALIZED ROR						
24	FIRM SALES OF GAS		1,488,864	252,422	1,066,892	31,233	34,341
25	INTERR SALES GAS COST REV	GASSALES	0	0	0	0	0
26	INTERR SALES PROFIT MARGINS	DEMGAS	0	0	0	0	0
27	INTERRUPTIBLE TRANSPORTATION	DISTR	0	0	0	0	0
28	SALES FOR RESALE	DEMGAS	0	0	0	0	0
29	TOTAL SALES OF GAS		1,488,864	252,422	1,066,892	31,233	34,341
30							
31	OTHER OPERATING REVENUES						
32	FORFEITED DISCOUNTS	FORFDISC	15,288	72	0	0	1,814
33	MISCELLANEOUS SERVICE REV	CUST487B	953	0	0	0	0
34	OTHER REVENUE	PLANT	1,078	203	813	19	10
35	OTHER REVENUE	PLANT	0	0	0	0	0
36	OTHER REVENUE	PLANT	0	0	0	0	0
37	TOTAL OTHER OPERATING REV		17,319	274	813	19	1,825
38							
39	TOTAL PROPOSED REVENUE @ EQUALIZED ROR		$1,506,183	$252,696	$1,067,706	$31,252	$36,166
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	RETURN AT PROPOSED RATES								
2									
3	SALES REVENUE								
4	FIRM SALES OF GAS		60,638,641	43,056,622	12,325,450	2,236,785	2,899,755	79,706	40,322
5	INTERR SALES GAS COST REV		0	0	0	0	0	0	0
6	INTERR SALES PROFIT MARGINS		0	0	0	0	0	0	0
7	INTERRUPTIBLE TRANSPORTATION		0	0	0	0	0	0	0
8	SALES FOR RESALE		0	0	0	0	0	0	0
9	TOTAL SALES OF GAS		60,638,641	43,056,622	12,325,450	2,236,785	2,899,755	79,706	40,322
10									
11	OTHER OPERATING REVENUES								
12	FORFEITED DISCOUNTS		495,690	367,395	109,583	1,538	15,360	0	1,814
13	MISCELLANEOUS SERVICE REV		1,211,079	1,157,058	52,906	162	953	0	0
14	OTHER REVENUE		37,974	26,417	6,400	3,035	2,094	19	10
15	OTHER REVENUE		0	0	0	0	0	0	0
16	OTHER REVENUE		0	0	0	0	0	0	0
17	TOTAL OTHER OPERATING REV		1,744,743	1,550,869	168,889	4,734	18,407	19	1,825
18									
19	TOTAL GAS OPERATING REVENUE		$62,383,384	$44,607,492	$12,494,339	$2,241,519	$2,918,162	$79,725	$42,147
20									
21	OPERATING EXPENSES								
22	OPERATION & MAINT EXPENSE		$25,116,748	$19,979,779	$3,290,835	$1,007,825	$802,622	$12,181	$23,504
23	CHANGE IN GAS COSTS	GASSALES	0	0	0	0	0	0	0
24	INCREASE IN UNCOLLECTIBLES	REVCHGP	0	0	0	0	0	0	0
25	TOTAL O&M AT PROPOSED		25,116,748	19,979,779	3,290,835	1,007,825	802,622	12,181	23,504
26	AMORTIZATION & DEPRECIATION EXP		8,240,005	6,043,745	1,262,380	542,363	386,207	3,393	1,917
27	TAXES OTHER THAN INCOME		4,342,079	3,076,211	709,027	326,518	227,175	2,024	1,124
28	TAX EXPENSE		7,291,517	5,032,091	1,255,785	584,979	411,639	4,205	2,819
29	TOTAL OPERATING EXPENSES		$44,990,348	$34,131,826	$6,518,027	$2,461,685	$1,827,643	$21,803	$29,364
30									
31	RETURN AT PROPOSED RATES		$17,393,035	$10,475,666	$5,976,312	($220,166)	$1,090,518	$57,921	$12,783
32									
33	RATE OF RETURN		9.54%	8.38%	18.95%	-1.45%	10.42%	58.49%	17.93%
34	INDEX RATE OF RETURN		1.000	0.879	1.987	-0.152	1.092	6.130	1.879
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	RETURN AT PROPOSED RATES							
2								
3	SALES REVENUE							
4	FIRM SALES OF GAS		11,396,784	928,667	159,205	2,077,580	1,941,150	958,604
5	INTERR SALES GAS COST REV		0	0	0	0	0	0
6	INTERR SALES PROFIT MARGINS		0	0	0	0	0	0
7	INTERRUPTIBLE TRANSPORTATION		0	0	0	0	0	0
8	SALES FOR RESALE		0	0	0	0	0	0
9	TOTAL SALES OF GAS		11,396,784	928,667	159,205	2,077,580	1,941,150	958,604
10								
11	OTHER OPERATING REVENUES							
12	FORFEITED DISCOUNTS		108,913	670	706	832	15,288	72
13	MISCELLANEOUS SERVICE REV		52,906	0	162	0	953	0
14	OTHER REVENUE		5,738	662	136	2,899	1,078	1,016
15	OTHER REVENUE		0	0	0	0	0	0
16	OTHER REVENUE		0	0	0	0	0	0
17	TOTAL OTHER OPERATING REV		167,557	1,332	1,004	3,731	17,319	1,088
18								
19	TOTAL GAS OPERATING REVENUE		$11,564,341	$929,999	$160,209	$2,081,310	$1,958,469	$959,692
20								
21	OPERATING EXPENSES							
22	OPERATION & MAINT EXPENSE		$3,047,425	$243,411	$33,475	$974,351	$456,349	$346,273
23	CHANGE IN GAS COSTS	GASSALES	0	0	0	0	0	0
24	INCREASE IN UNCOLLECTIBLES	REVCHGP	0	0	0	0	0	0
25	TOTAL O&M AT PROPOSED		3,047,425	243,411	33,475	974,351	456,349	346,273
26	AMORTIZATION & DEPRECIATION EXP		1,145,232	117,148	21,305	521,058	204,325	181,882
27	TAXES OTHER THAN INCOME		637,615	71,411	14,406	312,113	117,790	109,385
28	TAX EXPENSE		1,128,235	127,550	23,928	561,051	214,174	197,464
29	TOTAL OPERATING EXPENSES		$5,958,506	$559,521	$93,113	$2,368,572	$992,639	$835,004
30								
31	RETURN AT PROPOSED RATES		$5,605,834	$370,478	$67,096	($287,261)	$965,831	$124,688
32								
33	RATE OF RETURN		19.81%	11.44%	11.05%	-1.97%	17.94%	2.45%
34	INDEX RATE OF RETURN		2.077	1.199	1.158	-0.207	1.881	0.257
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	RETURN AT PROPOSED RATES						
2							
3	SALES REVENUE						
4	FIRM SALES OF GAS		41,678,918	1,377,705	11,396,784	292,581	636,086
5	INTERR SALES GAS COST REV		0	0	0	0	0
6	INTERR SALES PROFIT MARGINS		0	0	0	0	0
7	INTERRUPTIBLE TRANSPORTATION		0	0	0	0	0
8	SALES FOR RESALE		0	0	0	0	0
9	TOTAL SALES OF GAS		41,678,918	1,377,705	11,396,784	292,581	636,086
10							
11	OTHER OPERATING REVENUES						
12	FORFEITED DISCOUNTS		347,702	19,692	108,913	134	536
13	MISCELLANEOUS SERVICE REV		1,095,040	62,018	52,906	0	0
14	OTHER REVENUE		25,050	1,367	5,738	242	420
15	OTHER REVENUE		0	0	0	0	0
16	OTHER REVENUE		0	0	0	0	0
17	TOTAL OTHER OPERATING REV		1,467,792	83,077	167,557	376	956
18							
19	TOTAL GAS OPERATING REVENUE		$43,146,710	$1,460,782	$11,564,341	$292,957	$637,042
20							
21	OPERATING EXPENSES						
22	OPERATION & MAINT EXPENSE		$18,951,733	$1,028,046	$3,047,425	$84,990	$158,421
23	CHANGE IN GAS COSTS	GASSALES	0	0	0	0	0
24	INCREASE IN UNCOLLECTIBLES	REVCHGP	0	0	0	0	0
25	TOTAL O&M AT PROPOSED		18,951,733	1,028,046	3,047,425	84,990	158,421
26	AMORTIZATION & DEPRECIATION EXP		5,728,693	315,051	1,145,232	42,422	74,727
27	TAXES OTHER THAN INCOME		2,916,631	159,579	637,615	26,142	45,269
28	TAX EXPENSE		4,783,935	248,156	1,128,235	45,473	82,077
29	TOTAL OPERATING EXPENSES		$32,380,992	$1,750,833	$5,958,506	$199,026	$360,494
30							
31	RETURN AT PROPOSED RATES		10,765,718	(290,052)	5,605,834	93,930	276,548
32							
33	RATE OF RETURN		9.08%	-4.50%	19.81%	8.09%	13.31%
34	INDEX RATE OF RETURN		95.21%	-47.15%	207.67%	84.83%	139.53%
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	RETURN AT PROPOSED RATES				
2					
3	SALES REVENUE				
4	FIRM SALES OF GAS		159,205	144,048	1,933,532
5	INTERR SALES GAS COST REV		0	0	0
6	INTERR SALES PROFIT MARGINS		0	0	0
7	INTERRUPTIBLE TRANSPORTATION		0	0	0
8	SALES FOR RESALE		0	0	0
9	TOTAL SALES OF GAS		159,205	144,048	1,933,532
10					
11	OTHER OPERATING REVENUES				
12	FORFEITED DISCOUNTS		706	176	655
13	MISCELLANEOUS SERVICE REV		162	0	0
14	OTHER REVENUE		136	177	2,721
15	OTHER REVENUE		0	0	0
16	OTHER REVENUE		0	0	0
17	TOTAL OTHER OPERATING REV		1,004	354	3,377
18					
19	TOTAL GAS OPERATING REVENUE		$160,209	$144,402	$1,936,909
20					
21	OPERATING EXPENSES				
22	OPERATION & MAINT EXPENSE		$33,475	$56,760	$917,590
23	CHANGE IN GAS COSTS	GASSALES	0	0	0
24	INCREASE IN UNCOLLECTIBLES	REVCHGP	0	0	0
25	TOTAL O&M AT PROPOSED		33,475	56,760	917,590
26	AMORTIZATION & DEPRECIATION EXP		21,305	31,577	489,481
27	TAXES OTHER THAN INCOME		14,406	19,137	292,975
28	TAX EXPENSE		23,928	33,887	527,164
29	TOTAL OPERATING EXPENSES		$93,113	$141,361	$2,227,211
30					
31	RETURN AT PROPOSED RATES		67,096	3,040	(290,302)
32					
33	RATE OF RETURN		11.05%	0.35%	-2.12%
34	INDEX RATE OF RETURN		115.76%	3.64%	-22.23%
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	RETURN AT PROPOSED RATES						
2							
3	SALES REVENUE						
4	FIRM SALES OF GAS		1,941,150	176,749	781,855	79,706	40,322
5	INTERR SALES GAS COST REV		0	0	0	0	0
6	INTERR SALES PROFIT MARGINS		0	0	0	0	0
7	INTERRUPTIBLE TRANSPORTATION		0	0	0	0	0
8	SALES FOR RESALE		0	0	0	0	0
9	TOTAL SALES OF GAS		1,941,150	176,749	781,855	79,706	40,322
10							
11	OTHER OPERATING REVENUES						
12	FORFEITED DISCOUNTS		15,288	72	0	0	1,814
13	MISCELLANEOUS SERVICE REV		953	0	0	0	0
14	OTHER REVENUE		1,078	203	813	19	10
15	OTHER REVENUE		0	0	0	0	0
16	OTHER REVENUE		0	0	0	0	0
17	TOTAL OTHER OPERATING REV		17,319	274	813	19	1,825
18							
19	TOTAL GAS OPERATING REVENUE		$1,958,469	$177,024	$782,669	$79,725	$42,147
20							
21	OPERATING EXPENSES						
22	OPERATION & MAINT EXPENSE		$456,349	$60,353	$285,920	$12,181	$23,504
23	CHANGE IN GAS COSTS	GASSALES	0	0	0	0	0
24	INCREASE IN UNCOLLECTIBLES	REVCHGP	0	0	0	0	0
25	TOTAL O&M AT PROPOSED		456,349	60,353	285,920	12,181	23,504
26	AMORTIZATION & DEPRECIATION EXP		204,325	35,733	146,149	3,393	1,917
27	TAXES OTHER THAN INCOME		117,790	21,744	87,641	2,024	1,124
28	TAX EXPENSE		214,174	38,990	158,474	4,205	2,819
29	TOTAL OPERATING EXPENSES		$992,639	$156,819	$678,185	$21,803	$29,364
30							
31	RETURN AT PROPOSED RATES		965,831	20,204	104,484	57,921	12,783
32							
33	RATE OF RETURN		17.94%	2.01%	2.56%	58.49%	17.93%
34	INDEX RATE OF RETURN		188.07%	21.07%	26.82%	612.98%	187.93%
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
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		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	DEVELOPMENT OF RATE BASE								
2									
3	**GAS PLANT IN SERVICE**								
4									
5	INTANGIBLE PLANT								
6	302-FRANCHISES & CONSENTS	LABOR	$362,992	$295,006	$43,810	$13,369	$10,672	$83	$52
7	302-FRANCHISES & CONSENTS - ACQ ADJ	LABOR	(36,464)	(29,635)	(4,401)	(1,343)	(1,072)	(8)	(5)
8	303-MISC. INTANGIBLE PLANT	LABOR	777,500	631,879	93,837	28,635	22,858	178	112
9	303-MISC. INTANGIBLE PLANT - ACQ ADJ	LABOR	(36,142)	(29,373)	(4,362)	(1,331)	(1,063)	(8)	(5)
10	TOTAL INTANGIBLE PLANT		1,067,886	867,877	128,885	39,330	31,395	245	154
11									
12	TRANSMISSION PLANT								
13	365-LAND & LAND RIGHTS	TRANS	86,073	47,032	19,874	11,449	7,606	73	38
14	365-LAND & LAND RIGHTS - ACQ ADJ	TRANS	(15,425)	(8,429)	(3,562)	(2,052)	(1,363)	(13)	(7)
15	366-STRUCTURES & IMPROVEMENTS	TRANS	15,792	8,629	3,646	2,101	1,395	13	7
16	366-STRUCTURES & IMPROVE - ACQ ADJ	TRANS	(2,352)	(1,285)	(543)	(313)	(208)	(2)	(1)
17	367-MAINS	TRANS	17,486,880	9,555,200	4,037,689	2,325,989	1,545,269	14,924	7,808
18	367-MAINS - ACQ ADJ	TRANS	(1,604,647)	(876,813)	(370,510)	(213,440)	(141,798)	(1,370)	(716)
19	369-MEASURING & REG STATION EQUIP.	TRANS	792,065	432,801	182,886	105,355	69,993	676	354
20	369-MEAS & REG STA EQUIP - ACQ ADJ	TRANS	(424,444)	(231,925)	(98,003)	(56,457)	(37,507)	(362)	(190)
21	371-OTHER EQUIPMENT	TRANS	0	0	0	0	0	0	0
22	371-OTHER EQUIPMENT - ACQ ADJ	TRANS	(24,187)	(13,216)	(5,585)	(3,217)	(2,137)	(21)	(11)
23	TOTAL TRANSMISSION PLANT		16,309,754	8,911,994	3,765,893	2,169,416	1,441,250	13,920	7,282
24									
25	DISTRIBUTION PLANT								
26	374-LAND & LAND RIGHTS	DISTR	241,754	132,100	55,821	32,157	21,363	206	108
27	374-LAND & LAND RIGHTS - ACQ ADJ	DISTR	(38,784)	(21,193)	(8,955)	(5,159)	(3,427)	(33)	(17)
28	375-STRUCTURES & IMPROV	DISTR	10,258	5,605	2,369	1,365	907	9	5
29	375-STRUCTURES & IMPROV - ACQ ADJ	DISTR	(247)	(135)	(57)	(33)	(22)	(0)	(0)
30	376-MAINS	DISTMAIN	157,127,396	85,857,725	36,280,434	20,900,047	13,884,933	134,102	70,155
31	376-MAINS - ACQ ADJ	DISTMAIN	(17,621,607)	(9,628,818)	(4,068,797)	(2,343,910)	(1,557,175)	(15,039)	(7,868)
32	378-MEAS. & REG. EQUIP-GEN	DISTREG	2,344,082	1,280,856	541,244	311,794	207,140	2,001	1,047
33	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	DISTREG	(188,503)	(103,002)	(43,525)	(25,073)	(16,657)	(161)	(84)
34	379-MEAS. & REG. EQUIP-CITY GATE	DISTREG	2,437,071	1,331,667	562,715	324,163	215,358	2,080	1,088
35	379-MEAS & REG EQ-CITY GATE - ACQ ADJ	DISTREG	(239,569)	(130,906)	(55,316)	(31,866)	(21,170)	(204)	(107)
36	380-SERVICES	CUST380	86,448,392	78,959,861	6,824,037	17,540	643,964	0	2,990
37	380-SERVICES - ACQ ADJ	CUST380	(6,640,413)	(6,065,192)	(524,179)	(1,347)	(49,465)	0	(230)
38	381-METERS	CUST381	13,780,226	12,484,937	1,130,574	45,126	119,116	0	473
39	381-METERS - ACQ ADJ	CUST381	(1,160,990)	(1,051,861)	(95,251)	(3,802)	(10,036)	0	(40)
40	382-METER INSTALLATIONS	CUST382	8,633,492	7,821,976	708,319	28,272	74,628	0	296
41	382-METER INSTALLATIONS - ACQ ADJ	CUST382	(744,797)	(674,789)	(61,106)	(2,439)	(6,438)	0	(26)
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	DEVELOPMENT OF RATE BASE							
2								
3	**GAS PLANT IN SERVICE**							
4								
5	INTANGIBLE PLANT							
6	302-FRANCHISES & CONSENTS	LABOR	$40,722	$3,088	$429	$12,940	$6,140	$4,531
7	302-FRANCHISES & CONSENTS - ACQ ADJ	LABOR	(4,091)	(310)	(43)	(1,300)	(617)	(455)
8	303-MISC. INTANGIBLE PLANT	LABOR	87,222	6,615	920	27,716	13,152	9,706
9	303-MISC. INTANGIBLE PLANT - ACQ ADJ	LABOR	(4,055)	(307)	(43)	(1,288)	(611)	(451)
10	TOTAL INTANGIBLE PLANT		119,799	9,086	1,263	38,067	18,065	13,331
11								
12	TRANSMISSION PLANT							
13	365-LAND & LAND RIGHTS	TRANS	17,571	2,303	348	11,101	3,772	3,834
14	365-LAND & LAND RIGHTS - ACQ ADJ	TRANS	(3,149)	(413)	(62)	(1,989)	(676)	(687)
15	366-STRUCTURES & IMPROVEMENTS	TRANS	3,224	422	64	2,037	692	703
16	366-STRUCTURES & IMPROVE - ACQ ADJ	TRANS	(480)	(63)	(10)	(303)	(103)	(105)
17	367-MAINS	TRANS	3,569,893	467,797	70,747	2,255,242	766,349	778,921
18	367-MAINS - ACQ ADJ	TRANS	(327,584)	(42,926)	(6,492)	(206,948)	(70,322)	(71,476)
19	369-MEASURING & REG STATION EQUIP.	TRANS	161,698	21,189	3,204	102,151	34,712	35,281
20	369-MEAS & REG STA EQUIP - ACQ ADJ	TRANS	(86,649)	(11,354)	(1,717)	(54,739)	(18,601)	(18,906)
21	371-OTHER EQUIPMENT	TRANS	0	0	0	0	0	0
22	371-OTHER EQUIPMENT - ACQ ADJ	TRANS	(4,938)	(647)	(98)	(3,119)	(1,060)	(1,077)
23	TOTAL TRANSMISSION PLANT		3,329,586	436,307	65,985	2,103,431	714,762	726,488
24								
25	DISTRIBUTION PLANT							
26	374-LAND & LAND RIGHTS	DISTR	49,353	6,467	978	31,178	10,595	10,768
27	374-LAND & LAND RIGHTS - ACQ ADJ	DISTR	(7,918)	(1,038)	(157)	(5,002)	(1,700)	(1,728)
28	375-STRUCTURES & IMPROV	DISTR	2,094	274	42	1,323	450	457
29	375-STRUCTURES & IMPROV - ACQ ADJ	DISTR	(50)	(7)	(1)	(32)	(11)	(11)
30	376-MAINS	DISTMAIN	32,077,073	4,203,361	635,693	20,264,354	6,885,984	6,998,949
31	376-MAINS - ACQ ADJ	DISTMAIN	(3,597,397)	(471,401)	(71,292)	(2,272,618)	(772,253)	(784,922)
32	378-MEAS. & REG. EQUIP-GEN	DISTREG	478,537	62,707	9,483	302,311	102,728	104,413
33	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	DISTREG	(38,482)	(5,043)	(763)	(24,311)	(8,261)	(8,397)
34	379-MEAS. & REG. EQUIP-CITY GATE	DISTREG	497,521	65,195	9,860	314,303	106,803	108,555
35	379-MEAS & REG EQ-CITY GATE - ACQ ADJ	DISTREG	(48,907)	(6,409)	(969)	(30,897)	(10,499)	(10,671)
36	380-SERVICES	CUST380	6,808,414	15,623	11,960	5,580	640,974	2,990
37	380-SERVICES - ACQ ADJ	CUST380	(522,979)	(1,200)	(919)	(429)	(49,236)	(230)
38	381-METERS	CUST381	1,076,530	54,044	1,891	43,235	101,349	17,767
39	381-METERS - ACQ ADJ	CUST381	(90,698)	(4,553)	(159)	(3,643)	(8,539)	(1,497)
40	382-METER INSTALLATIONS	CUST382	674,460	33,859	1,185	27,088	63,497	11,131
41	382-METER INSTALLATIONS - ACQ ADJ	CUST382	(58,185)	(2,921)	(102)	(2,337)	(5,478)	(960)
42								
43								
44								
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	DEVELOPMENT OF RATE BASE						
2							
3	**GAS PLANT IN SERVICE**						
4							
5	INTANGIBLE PLANT						
6	302-FRANCHISES & CONSENTS	LABOR	$279,412	$15,594	$40,722	$1,160	$1,929
7	302-FRANCHISES & CONSENTS - ACQ ADJ	LABOR	(28,068)	(1,567)	(4,091)	(116)	(194)
8	303-MISC. INTANGIBLE PLANT	LABOR	598,477	33,402	87,222	2,484	4,131
9	303-MISC. INTANGIBLE PLANT - ACQ ADJ	LABOR	(27,820)	(1,553)	(4,055)	(115)	(192)
10	TOTAL INTANGIBLE PLANT		822,000	45,877	119,799	3,412	5,674
11							
12	TRANSMISSION PLANT						
13	365-LAND & LAND RIGHTS	TRANS	44,704	2,328	17,571	784	1,519
14	365-LAND & LAND RIGHTS - ACQ ADJ	TRANS	(8,011)	(417)	(3,149)	(140)	(272)
15	366-STRUCTURES & IMPROVEMENTS	TRANS	8,202	427	3,224	144	279
16	366-STRUCTURES & IMPROVE - ACQ ADJ	TRANS	(1,222)	(64)	(480)	(21)	(42)
17	367-MAINS	TRANS	9,082,152	473,048	3,569,893	159,180	308,617
18	367-MAINS - ACQ ADJ	TRANS	(833,405)	(43,408)	(327,584)	(14,607)	(28,320)
19	369-MEASURING & REG STATION EQUIP.	TRANS	411,374	21,427	161,698	7,210	13,979
20	369-MEAS & REG STA EQUIP - ACQ ADJ	TRANS	(220,443)	(11,482)	(86,649)	(3,864)	(7,491)
21	371-OTHER EQUIPMENT	TRANS	0	0	0	0	0
22	371-OTHER EQUIPMENT - ACQ ADJ	TRANS	(12,562)	(654)	(4,938)	(220)	(427)
23	TOTAL TRANSMISSION PLANT		8,470,789	441,205	3,329,586	148,465	287,842
24							
25	DISTRIBUTION PLANT						
26	374-LAND & LAND RIGHTS	DISTR	125,560	6,540	49,353	2,201	4,267
27	374-LAND & LAND RIGHTS - ACQ ADJ	DISTR	(20,143)	(1,049)	(7,918)	(353)	(684)
28	375-STRUCTURES & IMPROV	DISTR	5,328	278	2,094	93	181
29	375-STRUCTURES & IMPROV - ACQ ADJ	DISTR	(128)	(7)	(50)	(2)	(4)
30	376-MAINS	DISTMAIN	81,607,175	4,250,551	32,077,073	1,430,304	2,773,057
31	376-MAINS - ACQ ADJ	DISTMAIN	(9,152,125)	(476,693)	(3,597,397)	(160,406)	(310,994)
32	378-MEAS. & REG. EQUIP-GEN	DISTREG	1,217,445	63,411	478,537	21,338	41,369
33	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	DISTREG	(97,903)	(5,099)	(38,482)	(1,716)	(3,327)
34	379-MEAS. & REG. EQUIP-CITY GATE	DISTREG	1,265,740	65,927	497,521	22,184	43,011
35	379-MEAS & REG EQ-CITY GATE - ACQ ADJ	DISTREG	(124,425)	(6,481)	(48,907)	(2,181)	(4,228)
36	380-SERVICES	CUST380	74,727,701	4,232,160	6,808,414	15,623	0
37	380-SERVICES - ACQ ADJ	CUST380	(5,740,105)	(325,088)	(522,979)	(1,200)	0
38	381-METERS	CUST381	11,815,759	669,179	1,076,530	30,265	23,779
39	381-METERS - ACQ ADJ	CUST381	(995,482)	(56,379)	(90,698)	(2,550)	(2,003)
40	382-METER INSTALLATIONS	CUST382	7,402,727	419,249	674,460	18,961	14,898
41	382-METER INSTALLATIONS - ACQ ADJ	CUST382	(638,621)	(36,168)	(58,185)	(1,636)	(1,285)
42							
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
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		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	DEVELOPMENT OF RATE BASE				
2					
3	**GAS PLANT IN SERVICE**				
4					
5	INTANGIBLE PLANT				
6	302-FRANCHISES & CONSENTS	LABOR	$429	$816	$12,123
7	302-FRANCHISES & CONSENTS - ACQ ADJ	LABOR	(43)	(82)	(1,218)
8	303-MISC. INTANGIBLE PLANT	LABOR	920	1,749	25,967
9	303-MISC. INTANGIBLE PLANT - ACQ ADJ	LABOR	(43)	(81)	(1,207)
10	TOTAL INTANGIBLE PLANT		1,263	2,402	35,665
11					
12	TRANSMISSION PLANT				
13	365-LAND & LAND RIGHTS	TRANS	348	636	10,465
14	365-LAND & LAND RIGHTS - ACQ ADJ	TRANS	(62)	(114)	(1,875)
15	366-STRUCTURES & IMPROVEMENTS	TRANS	64	117	1,920
16	366-STRUCTURES & IMPROVE - ACQ ADJ	TRANS	(10)	(17)	(286)
17	367-MAINS	TRANS	70,747	129,126	2,126,116
18	367-MAINS - ACQ ADJ	TRANS	(6,492)	(11,849)	(195,099)
19	369-MEASURING & REG STATION EQUIP.	TRANS	3,204	5,849	96,302
20	369-MEAS & REG STA EQUIP - ACQ ADJ	TRANS	(1,717)	(3,134)	(51,605)
21	371-OTHER EQUIPMENT	TRANS	0	0	0
22	371-OTHER EQUIPMENT - ACQ ADJ	TRANS	(98)	(179)	(2,941)
23	TOTAL TRANSMISSION PLANT		65,985	120,434	1,982,997
24					
25	DISTRIBUTION PLANT				
26	374-LAND & LAND RIGHTS	DISTR	978	1,785	29,393
27	374-LAND & LAND RIGHTS - ACQ ADJ	DISTR	(157)	(286)	(4,716)
28	375-STRUCTURES & IMPROV	DISTR	42	76	1,247
29	375-STRUCTURES & IMPROV - ACQ ADJ	DISTR	(1)	(2)	(30)
30	376-MAINS	DISTMAIN	635,693	1,160,259	19,104,095
31	376-MAINS - ACQ ADJ	DISTMAIN	(71,292)	(130,121)	(2,142,496)
32	378-MEAS. & REG. EQUIP-GEN	DISTREG	9,483	17,309	285,002
33	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	DISTREG	(763)	(1,392)	(22,919)
34	379-MEAS. & REG. EQUIP-CITY GATE	DISTREG	9,860	17,996	296,308
35	379-MEAS & REG EQ-CITY GATE - ACQ ADJ	DISTREG	(969)	(1,769)	(29,128)
36	380-SERVICES	CUST380	11,960	5,580	0
37	380-SERVICES - ACQ ADJ	CUST380	(919)	(429)	0
38	381-METERS	CUST381	1,891	10,809	32,427
39	381-METERS - ACQ ADJ	CUST381	(159)	(911)	(2,732)
40	382-METER INSTALLATIONS	CUST382	1,185	6,772	20,316
41	382-METER INSTALLATIONS - ACQ ADJ	CUST382	(102)	(584)	(1,753)
42					
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	DEVELOPMENT OF RATE BASE						
2							
3	**GAS PLANT IN SERVICE**						
4							
5	INTANGIBLE PLANT						
6	302-FRANCHISES & CONSENTS	LABOR	$6,140	$852	$3,679	$83	$52
7	302-FRANCHISES & CONSENTS - ACQ ADJ	LABOR	(617)	(86)	(370)	(8)	(5)
8	303-MISC. INTANGIBLE PLANT	LABOR	13,152	1,825	7,881	178	112
9	303-MISC. INTANGIBLE PLANT - ACQ ADJ	LABOR	(611)	(85)	(366)	(8)	(5)
10	TOTAL INTANGIBLE PLANT		18,065	2,506	10,824	245	154
11							
12	TRANSMISSION PLANT						
13	365-LAND & LAND RIGHTS	TRANS	3,772	746	3,088	73	38
14	365-LAND & LAND RIGHTS - ACQ ADJ	TRANS	(676)	(134)	(553)	(13)	(7)
15	366-STRUCTURES & IMPROVEMENTS	TRANS	692	137	567	13	7
16	366-STRUCTURES & IMPROVE - ACQ ADJ	TRANS	(103)	(20)	(84)	(2)	(1)
17	367-MAINS	TRANS	766,349	151,478	627,443	14,924	7,808
18	367-MAINS - ACQ ADJ	TRANS	(70,322)	(13,900)	(57,576)	(1,370)	(716)
19	369-MEASURING & REG STATION EQUIP.	TRANS	34,712	6,861	28,420	676	354
20	369-MEAS & REG STA EQUIP - ACQ ADJ	TRANS	(18,601)	(3,677)	(15,229)	(362)	(190)
21	371-OTHER EQUIPMENT	TRANS	0	0	0	0	0
22	371-OTHER EQUIPMENT - ACQ ADJ	TRANS	(1,060)	(210)	(868)	(21)	(11)
23	TOTAL TRANSMISSION PLANT		714,762	141,281	585,207	13,920	7,282
24							
25	DISTRIBUTION PLANT						
26	374-LAND & LAND RIGHTS	DISTR	10,595	2,094	8,674	206	108
27	374-LAND & LAND RIGHTS - ACQ ADJ	DISTR	(1,700)	(336)	(1,392)	(33)	(17)
28	375-STRUCTURES & IMPROV	DISTR	450	89	368	9	5
29	375-STRUCTURES & IMPROV - ACQ ADJ	DISTR	(11)	(2)	(9)	(0)	(0)
30	376-MAINS	DISTMAIN	6,885,984	1,361,093	5,637,856	134,102	70,155
31	376-MAINS - ACQ ADJ	DISTMAIN	(772,253)	(152,645)	(632,277)	(15,039)	(7,868)
32	378-MEAS. & REG. EQUIP-GEN	DISTREG	102,728	20,305	84,108	2,001	1,047
33	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	DISTREG	(8,261)	(1,633)	(6,764)	(161)	(84)
34	379-MEAS. & REG. EQUIP-CITY GATE	DISTREG	106,803	21,111	87,444	2,080	1,088
35	379-MEAS & REG EQ-CITY GATE - ACQ ADJ	DISTREG	(10,499)	(2,075)	(8,596)	(204)	(107)
36	380-SERVICES	CUST380	640,974	2,990	0	0	2,990
37	380-SERVICES - ACQ ADJ	CUST380	(49,236)	(230)	0	0	(230)
38	381-METERS	CUST381	101,349	473	17,294	0	473
39	381-METERS - ACQ ADJ	CUST381	(8,539)	(40)	(1,457)	0	(40)
40	382-METER INSTALLATIONS	CUST382	63,497	296	10,835	0	296
41	382-METER INSTALLATIONS - ACQ ADJ	CUST382	(5,478)	(26)	(935)	0	(26)
42							
43							
44							
45							

UNS GAS COMPANY
COST OF SERVICE STUDY
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UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	DEVELOPMENT OF RATE BASE								
2									
3	**GAS PLANT IN SERVICE CONTINUED**								
4									
5	DISTRIBUTION PLANT CONTINUED								
6	383-REGULATORS	CUST383	2,886,748	2,657,594	229,154	0	0	0	0
7	383-REGULATORS - ACQ ADJ	CUST383	(178,700)	(164,514)	(14,185)	0	0	0	0
8	384-REGULATOR INSTALLATIONS	CUST384	1,352,659	1,245,283	107,376	0	0	0	0
9	384-REGULATOR INSTALLATIONS - ACQ ADJ	CUST384	(82,263)	(75,733)	(6,530)	0	0	0	0
10	385-INDUSTRIAL MEAS. EQUIP	CUST385	1,433,311	0	459,395	735,031	238,885	0	0
11	385-INDUSTRIAL MEAS. EQUIP - ACQ ADJ	CUST385	(106,448)	0	(34,118)	(54,589)	(17,741)	0	0
12	387-OTHER EQUIPMENT	DISTMAIN	1,069,684	584,498	246,988	142,282	94,525	913	478
13	387-OTHER EQUIPMENT - ACQ ADJ	DISTMAIN	(146,048)	(79,803)	(33,722)	(19,426)	(12,906)	(125)	(65)
14	TOTAL DISTRIBUTION PLANT		250,616,704	174,366,155	42,202,683	20,050,133	13,805,781	123,748	68,203
15									
16	GENERAL PLANT								
17	389-LAND & LAND RIGHTS	LABOR	394,121	320,304	47,567	14,515	11,587	90	57
18	389-LAND & LAND RIGHTS - ACQ ADJ	LABOR	(49,201)	(39,986)	(5,938)	(1,812)	(1,446)	(11)	(7)
19	390-STRUCTURES & IMPROVE	LABOR	5,345,351	4,344,197	645,137	196,869	157,149	1,226	772
20	390-STRUCTURES & IMPROVE - ACQ ADJ	LABOR	(123,017)	(99,977)	(14,847)	(4,531)	(3,617)	(28)	(18)
21	391-OFFICE FURN & EQUIPMENT	LABOR	2,102,879	1,709,022	253,799	77,449	61,823	482	304
22	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	LABOR	(643,851)	(523,261)	(77,707)	(23,713)	(18,929)	(148)	(93)
23	392-TRANSPORTATION EQUIP	LABOR	7,181,119	5,836,136	866,698	264,481	211,120	1,646	1,038
24	392-TRANSPORTATION EQUIP - ACQ ADJ	LABOR	(85,465)	(69,458)	(10,315)	(3,148)	(2,513)	(20)	(12)
25	393-STORES EQUIPMENT	LABOR	200,996	163,350	24,258	7,403	5,909	46	29
26	393-STORES EQUIPMENT - ACQ ADJ	LABOR	(17,775)	(14,446)	(2,145)	(655)	(523)	(4)	(3)
27	394-TOOLS, SHOP & GARAGE EQUIP	LABOR	2,271,486	1,846,050	274,149	83,659	66,780	521	328
28	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	LABOR	(230,699)	(187,491)	(27,843)	(8,497)	(6,782)	(53)	(33)
29	395-LABORATORY EQUIPMENT	LABOR	786,828	639,460	94,963	28,979	23,132	180	114
30	395-LABORATORY EQUIPMENT - ACQ ADJ	LABOR	(78,875)	(64,102)	(9,520)	(2,905)	(2,319)	(18)	(11)
31	396-POWER OPERATED EQUIP	LABOR	1,279,076	1,039,513	154,373	47,108	37,604	293	185
32	396-POWER OPERATED EQUIP - ACQ ADJ	LABOR	(5,511)	(4,479)	(665)	(203)	(162)	(1)	(1)
33	397-COMMUNICATION EQUIP	LABOR	1,101,825	895,460	132,981	40,580	32,393	253	159
34	397-COMMUNICATION EQUIP - ACQ ADJ	LABOR	(153,703)	(124,915)	(18,551)	(5,661)	(4,519)	(35)	(22)
35	398-MISCELLANEOUS EQUIP	LABOR	277,567	225,580	33,500	10,223	8,160	64	40
36	398-MISCELLANEOUS EQUIP - ACQ ADJ	LABOR	(29,611)	(24,065)	(3,574)	(1,091)	(871)	(7)	(4)
37	399-OTHER TANGIBLE PROPERTY	LABOR	0	0	0	0	0	0	0
38	TOTAL GENERAL PLANT		19,523,542	15,866,894	2,356,321	719,052	573,977	4,476	2,821
39									
40	COMMON PLANT	LABOR	0	0	0	0	0	0	0
41									
42	TOTAL GAS PLANT IN SERVICE		287,517,886	200,012,920	48,453,782	22,977,931	15,852,403	142,389	78,461
43									
44	TOTAL GAS PLANT IN SERVICE ACQ ADJ		(30,709,737)	(20,338,800)	(5,603,813)	(2,818,010)	(1,921,865)	(17,672)	(9,577)
45									

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
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		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	DEVELOPMENT OF RATE BASE							
2								
3	**GAS PLANT IN SERVICE CONTINUED**							
4								
5	DISTRIBUTION PLANT CONTINUED							
6	383-REGULATORS	CUST383	229,154	0	0	0	0	0
7	383-REGULATORS - ACQ ADJ	CUST383	(14,185)	0	0	0	0	0
8	384-REGULATOR INSTALLATIONS	CUST384	107,376	0	0	0	0	0
9	384-REGULATOR INSTALLATIONS - ACQ ADJ	CUST384	(6,530)	0	0	0	0	0
10	385-INDUSTRIAL MEAS. EQUIP	CUST385	0	459,395	367,516	367,516	0	238,885
11	385-INDUSTRIAL MEAS. EQUIP - ACQ ADJ	CUST385	0	(34,118)	(27,294)	(27,294)	0	(17,741)
12	387-OTHER EQUIPMENT	DISTMAIN	218,373	28,615	4,328	137,955	46,878	47,647
13	387-OTHER EQUIPMENT - ACQ ADJ	DISTMAIN	(29,815)	(3,907)	(591)	(18,835)	(6,400)	(6,505)
14	TOTAL DISTRIBUTION PLANT		37,803,738	4,398,945	940,688	19,109,445	7,096,880	6,708,900
15								
16	GENERAL PLANT							
17	389-LAND & LAND RIGHTS	LABOR	44,214	3,353	466	14,049	6,667	4,920
18	389-LAND & LAND RIGHTS - ACQ ADJ	LABOR	(5,519)	(419)	(58)	(1,754)	(832)	(614)
19	390-STRUCTURES & IMPROVE	LABOR	599,658	45,479	6,323	190,546	90,423	66,727
20	390-STRUCTURES & IMPROVE - ACQ ADJ	LABOR	(13,800)	(1,047)	(146)	(4,385)	(2,081)	(1,536)
21	391-OFFICE FURN & EQUIPMENT	LABOR	235,908	17,892	2,487	74,962	35,573	26,250
22	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	LABOR	(72,229)	(5,478)	(762)	(22,951)	(10,891)	(8,037)
23	392-TRANSPORTATION EQUIP	LABOR	805,601	61,098	8,494	255,986	121,477	89,643
24	392-TRANSPORTATION EQUIP - ACQ ADJ	LABOR	(9,588)	(727)	(101)	(3,047)	(1,446)	(1,067)
25	393-STORES EQUIPMENT	LABOR	22,548	1,710	238	7,165	3,400	2,509
26	393-STORES EQUIPMENT - ACQ ADJ	LABOR	(1,994)	(151)	(21)	(634)	(301)	(222)
27	394-TOOLS, SHOP & GARAGE EQUIP	LABOR	254,822	19,326	2,687	80,972	38,425	28,355
28	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	LABOR	(25,881)	(1,963)	(273)	(8,224)	(3,903)	(2,880)
29	395-LABORATORY EQUIPMENT	LABOR	88,269	6,694	931	28,048	13,310	9,822
30	395-LABORATORY EQUIPMENT - ACQ ADJ	LABOR	(8,848)	(671)	(93)	(2,812)	(1,334)	(985)
31	396-POWER OPERATED EQUIP	LABOR	143,491	10,883	1,513	45,595	21,637	15,967
32	396-POWER OPERATED EQUIP - ACQ ADJ	LABOR	(618)	(47)	(7)	(196)	(93)	(69)
33	397-COMMUNICATION EQUIP	LABOR	123,606	9,374	1,303	39,277	18,639	13,754
34	397-COMMUNICATION EQUIP - ACQ ADJ	LABOR	(17,243)	(1,308)	(182)	(5,479)	(2,600)	(1,919)
35	398-MISCELLANEOUS EQUIP	LABOR	31,138	2,362	328	9,894	4,695	3,465
36	398-MISCELLANEOUS EQUIP - ACQ ADJ	LABOR	(3,322)	(252)	(35)	(1,056)	(501)	(370)
37	399-OTHER TANGIBLE PROPERTY	LABOR	0	0	0	0	0	0
38	TOTAL GENERAL PLANT		2,190,212	166,109	23,094	695,958	330,263	243,714
39								
40	COMMON PLANT	LABOR	0	0	0	0	0	0
41								
42	TOTAL GAS PLANT IN SERVICE		43,443,335	5,010,447	1,031,030	21,946,902	8,159,970	7,692,433
43								
44	TOTAL GAS PLANT IN SERVICE ACQ ADJ		(5,005,134)	(598,679)	(112,389)	(2,705,621)	(978,349)	(943,517)
45								

UNS GAS COMPANY
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		ALLOC	RESIDENTIAL RESIDENTIAL SERVICE (14)	RESIDENTIAL CARES (15)	COMMERCIAL SM. VOL. (16)	COMMERCIAL LG. VOL. (17)	COMMERCIAL TRANS-PORTATION (18)
1	DEVELOPMENT OF RATE BASE						
2							
3	**GAS PLANT IN SERVICE CONTINUED**						
4							
5	DISTRIBUTION PLANT CONTINUED						
6	383-REGULATORS	CUST383	2,515,150	142,444	229,154	0	0
7	383-REGULATORS - ACQ ADJ	CUST383	(155,697)	(8,818)	(14,185)	0	0
8	384-REGULATOR INSTALLATIONS	CUST384	1,178,537	66,746	107,376	0	0
9	384-REGULATOR INSTALLATIONS - ACQ ADJ	CUST384	(71,674)	(4,059)	(6,530)	0	0
10	385-INDUSTRIAL MEAS. EQUIP	CUST385	0	0	0	257,261	202,134
11	385-INDUSTRIAL MEAS. EQUIP - ACQ ADJ	CUST385	0	0	0	(19,106)	(15,012)
12	387-OTHER EQUIPMENT	DISTMAIN	555,561	28,937	218,373	9,737	18,878
13	387-OTHER EQUIPMENT - ACQ ADJ	DISTMAIN	(75,853)	(3,951)	(29,815)	(1,329)	(2,578)
14	TOTAL DISTRIBUTION PLANT		165,344,526	9,021,630	37,803,738	1,617,488	2,781,458
15							
16	GENERAL PLANT						
17	389-LAND & LAND RIGHTS	LABOR	303,373	16,932	44,214	1,259	2,094
18	389-LAND & LAND RIGHTS - ACQ ADJ	LABOR	(37,872)	(2,114)	(5,519)	(157)	(261)
19	390-STRUCTURES & IMPROVE	LABOR	4,114,558	229,639	599,658	17,077	28,402
20	390-STRUCTURES & IMPROVE - ACQ ADJ	LABOR	(94,692)	(5,285)	(13,800)	(393)	(654)
21	391-OFFICE FURN & EQUIPMENT	LABOR	1,618,681	90,341	235,908	6,718	11,174
22	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	LABOR	(495,601)	(27,660)	(72,229)	(2,057)	(3,421)
23	392-TRANSPORTATION EQUIP	LABOR	5,527,632	308,505	805,601	22,941	38,157
24	392-TRANSPORTATION EQUIP - ACQ ADJ	LABOR	(65,786)	(3,672)	(9,588)	(273)	(454)
25	393-STORES EQUIPMENT	LABOR	154,715	8,635	22,548	642	1,068
26	393-STORES EQUIPMENT - ACQ ADJ	LABOR	(13,682)	(764)	(1,994)	(57)	(94)
27	394-TOOLS, SHOP & GARAGE EQUIP	LABOR	1,748,465	97,584	254,822	7,257	12,069
28	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	LABOR	(177,580)	(9,911)	(25,881)	(737)	(1,226)
29	395-LABORATORY EQUIPMENT	LABOR	605,657	33,803	88,269	2,514	4,181
30	395-LABORATORY EQUIPMENT - ACQ ADJ	LABOR	(60,714)	(3,389)	(8,848)	(252)	(419)
31	396-POWER OPERATED EQUIP	LABOR	984,563	54,950	143,491	4,086	6,796
32	396-POWER OPERATED EQUIP - ACQ ADJ	LABOR	(4,242)	(237)	(618)	(18)	(29)
33	397-COMMUNICATION EQUIP	LABOR	848,125	47,335	123,606	3,520	5,854
34	397-COMMUNICATION EQUIP - ACQ ADJ	LABOR	(118,312)	(6,603)	(17,243)	(491)	(817)
35	398-MISCELLANEOUS EQUIP	LABOR	213,656	11,924	31,138	887	1,475
36	398-MISCELLANEOUS EQUIP - ACQ ADJ	LABOR	(22,793)	(1,272)	(3,322)	(95)	(157)
37	399-OTHER TANGIBLE PROPERTY	LABOR	0	0	0	0	0
38	TOTAL GENERAL PLANT		15,028,152	838,742	2,190,212	62,371	103,737
39							
40	COMMON PLANT	LABOR	0	0	0	0	0
41							
42	TOTAL GAS PLANT IN SERVICE		189,665,466	10,347,454	43,443,335	1,831,735	3,178,712
43							
44	TOTAL GAS PLANT IN SERVICE ACQ ADJ		(19,294,959)	(1,043,841)	(5,005,134)	(214,093)	(384,586)
45							

UNS GAS COMPANY
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		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	DEVELOPMENT OF RATE BASE				
2					
3	**GAS PLANT IN SERVICE CONTINUED**				
4					
5	DISTRIBUTION PLANT CONTINUED				
6	383-REGULATORS	CUST383	0	0	0
7	383-REGULATORS - ACQ ADJ	CUST383	0	0	0
8	384-REGULATOR INSTALLATIONS	CUST384	0	0	0
9	384-REGULATOR INSTALLATIONS - ACQ ADJ	CUST384	0	0	0
10	385-INDUSTRIAL MEAS. EQUIP	CUST385	367,516	91,879	275,637
11	385-INDUSTRIAL MEAS. EQUIP - ACQ ADJ	CUST385	(27,294)	(6,824)	(20,471)
12	387-OTHER EQUIPMENT	DISTMAIN	4,328	7,899	130,056
13	387-OTHER EQUIPMENT - ACQ ADJ	DISTMAIN	(591)	(1,078)	(17,757)
14	TOTAL DISTRIBUTION PLANT		940,688	1,176,967	17,932,479
15					
16	GENERAL PLANT				
17	389-LAND & LAND RIGHTS	LABOR	466	886	13,163
18	389-LAND & LAND RIGHTS - ACQ ADJ	LABOR	(58)	(111)	(1,643)
19	390-STRUCTURES & IMPROVE	LABOR	6,323	12,022	178,524
20	390-STRUCTURES & IMPROVE - ACQ ADJ	LABOR	(146)	(277)	(4,109)
21	391-OFFICE FURN & EQUIPMENT	LABOR	2,487	4,730	70,232
22	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	LABOR	(762)	(1,448)	(21,503)
23	392-TRANSPORTATION EQUIP	LABOR	8,494	16,151	239,835
24	392-TRANSPORTATION EQUIP - ACQ ADJ	LABOR	(101)	(192)	(2,854)
25	393-STORES EQUIPMENT	LABOR	238	452	6,713
26	393-STORES EQUIPMENT - ACQ ADJ	LABOR	(21)	(40)	(594)
27	394-TOOLS, SHOP & GARAGE EQUIP	LABOR	2,687	5,109	75,863
28	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	LABOR	(273)	(519)	(7,705)
29	395-LABORATORY EQUIPMENT	LABOR	931	1,770	26,278
30	395-LABORATORY EQUIPMENT - ACQ ADJ	LABOR	(93)	(177)	(2,634)
31	396-POWER OPERATED EQUIP	LABOR	1,513	2,877	42,719
32	396-POWER OPERATED EQUIP - ACQ ADJ	LABOR	(7)	(12)	(184)
33	397-COMMUNICATION EQUIP	LABOR	1,303	2,478	36,799
34	397-COMMUNICATION EQUIP - ACQ ADJ	LABOR	(182)	(346)	(5,133)
35	398-MISCELLANEOUS EQUIP	LABOR	328	624	9,270
36	398-MISCELLANEOUS EQUIP - ACQ ADJ	LABOR	(35)	(67)	(989)
37	399-OTHER TANGIBLE PROPERTY	LABOR	0	0	0
38	TOTAL GENERAL PLANT		23,094	43,911	652,047
39					
40	COMMON PLANT	LABOR	0	0	0
41					
42	TOTAL GAS PLANT IN SERVICE		1,031,030	1,343,714	20,603,188
43					
44	TOTAL GAS PLANT IN SERVICE ACQ ADJ		(112,389)	(162,041)	(2,543,580)
45					

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	DEVELOPMENT OF RATE BASE						
2							
3	**GAS PLANT IN SERVICE CONTINUED**						
4							
5	DISTRIBUTION PLANT CONTINUED						
6	383-REGULATORS	CUST383	0	0	0	0	0
7	383-REGULATORS - ACQ ADJ	CUST383	0	0	0	0	0
8	384-REGULATOR INSTALLATIONS	CUST384	0	0	0	0	0
9	384-REGULATOR INSTALLATIONS - ACQ ADJ	CUST384	0	0	0	0	0
10	385-INDUSTRIAL MEAS. EQUIP	CUST385	0	91,879	147,006	0	0
11	385-INDUSTRIAL MEAS. EQUIP - ACQ ADJ	CUST385	0	(6,824)	(10,918)	0	0
12	387-OTHER EQUIPMENT	DISTMAIN	46,878	9,266	38,381	913	478
13	387-OTHER EQUIPMENT - ACQ ADJ	DISTMAIN	(6,400)	(1,265)	(5,240)	(125)	(65)
14	TOTAL DISTRIBUTION PLANT		7,096,880	1,344,521	5,364,379	123,748	68,203
15							
16	GENERAL PLANT						
17	389-LAND & LAND RIGHTS	LABOR	6,667	925	3,995	90	57
18	389-LAND & LAND RIGHTS - ACQ ADJ	LABOR	(832)	(115)	(499)	(11)	(7)
19	390-STRUCTURES & IMPROVE	LABOR	90,423	12,544	54,182	1,226	772
20	390-STRUCTURES & IMPROVE - ACQ ADJ	LABOR	(2,081)	(289)	(1,247)	(28)	(18)
21	391-OFFICE FURN & EQUIPMENT	LABOR	35,573	4,935	21,315	482	304
22	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	LABOR	(10,891)	(1,511)	(6,526)	(148)	(93)
23	392-TRANSPORTATION EQUIP	LABOR	121,477	16,853	72,790	1,646	1,038
24	392-TRANSPORTATION EQUIP - ACQ ADJ	LABOR	(1,446)	(201)	(866)	(20)	(12)
25	393-STORES EQUIPMENT	LABOR	3,400	472	2,037	46	29
26	393-STORES EQUIPMENT - ACQ ADJ	LABOR	(301)	(42)	(180)	(4)	(3)
27	394-TOOLS, SHOP & GARAGE EQUIP	LABOR	38,425	5,331	23,024	521	328
28	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	LABOR	(3,903)	(541)	(2,338)	(53)	(33)
29	395-LABORATORY EQUIPMENT	LABOR	13,310	1,847	7,976	180	114
30	395-LABORATORY EQUIPMENT - ACQ ADJ	LABOR	(1,334)	(185)	(800)	(18)	(11)
31	396-POWER OPERATED EQUIP	LABOR	21,637	3,002	12,965	293	185
32	396-POWER OPERATED EQUIP - ACQ ADJ	LABOR	(93)	(13)	(56)	(1)	(1)
33	397-COMMUNICATION EQUIP	LABOR	18,639	2,586	11,168	253	159
34	397-COMMUNICATION EQUIP - ACQ ADJ	LABOR	(2,600)	(361)	(1,558)	(35)	(22)
35	398-MISCELLANEOUS EQUIP	LABOR	4,695	651	2,814	64	40
36	398-MISCELLANEOUS EQUIP - ACQ ADJ	LABOR	(501)	(69)	(300)	(7)	(4)
37	399-OTHER TANGIBLE PROPERTY	LABOR	0	0	0	0	0
38	TOTAL GENERAL PLANT		330,263	45,818	197,897	4,476	2,821
39							
40	COMMON PLANT	LABOR	0	0	0	0	0
41							
42	TOTAL GAS PLANT IN SERVICE		8,159,970	1,534,126	6,158,307	142,389	78,461
43							
44	TOTAL GAS PLANT IN SERVICE ACQ ADJ		(978,349)	(186,512)	(757,005)	(17,672)	(9,577)
45							

UNS GAS COMPANY
COST OF SERVICE STUDY
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		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	DEVELOPMENT OF RATE BASE CONT.								
2									
3	**DEPRECIATION RESERVE CONTINUED**								
4									
5	**DEPRECIATION RESERVE**								
6	INTANGIBLE RESERVE								
7	302-FRANCHISES & CONSENTS	PLT302	185,148	150,470	22,346	6,819	5,443	42	27
8	302-FRANCHISES & CONSENTS - ACQ ADJ	PLT302	(7,030)	(5,714)	(849)	(259)	(207)	(2)	(1)
9	303-MISC. INTANGIBLE PLANT	PLT303	289,837	235,552	34,981	10,675	8,521	66	42
10	303-MISC. INTANGIBLE PLANT - ACQ ADJ	PLT303	(7,363)	(5,984)	(889)	(271)	(216)	(2)	(1)
11	TOTAL INTANGIBLE PLANT		460,590	374,325	55,589	16,964	13,541	106	67
12									
13	TRANSMISSION RESERVE								
14	365-LAND & LAND RIGHTS	PLT365	15,259	8,338	3,523	2,030	1,348	13	7
15	365-LAND & LAND RIGHTS - ACQ ADJ	PLT365	(125)	(68)	(29)	(17)	(11)	(0)	(0)
16	366-STRUCTURES & IMPROVEMENTS	PLT366	4,130	2,257	954	549	365	4	2
17	366-STRUCTURES & IMPROV - ADQ ADJ	PLT366	(759)	(415)	(175)	(101)	(67)	(1)	(0)
18	367-MAINS	PLT367	3,670,676	2,005,735	847,553	488,249	324,368	3,133	1,639
19	367-MAINS - ACQ ADJ	PLT367	(124,060)	(67,789)	(28,645)	(16,502)	(10,963)	(106)	(55)
20	369-MEASURING & REG STATION EQUIP.	PLT369	318,418	173,990	73,522	42,354	28,138	272	142
21	369-MEASURING & REG STA EQ - ACQ ADJ	PLT369	(33,265)	(18,177)	(7,681)	(4,425)	(2,940)	(28)	(15)
22	371-OTHER EQUIPMENT	PLT371	0	0	0	0	0	0	0
23	371-OTHER EQUIPMENT - ACQ ADJ	PLT371	(5,565)	(3,041)	(1,285)	(740)	(492)	(5)	(2)
24	TOTAL TRANSMISSION PLANT		3,844,709	2,100,830	887,736	511,398	339,747	3,281	1,717
25									
26	DISTRIBUTION RESERVE								
27	374.1-LAND	PLT374	31,809	17,381	7,345	4,231	2,811	27	14
28	374.1-LAND - ACQ ADJ	PLT374	(182)	(100)	(42)	(24)	(16)	(0)	(0)
29	375-STRUCTURES & IMPROV	PLT375	7,027	3,840	1,622	935	621	6	3
30	375-STRUCTURES & IMPROV - ACQ ADJ	PLT375	(39)	(21)	(9)	(5)	(3)	(0)	(0)
31	376-MAINS	PLT376	37,521,357	20,502,461	8,663,614	4,990,843	3,315,663	32,023	16,753
32	376-MAINS - ACQ ADJ	PLT376	(1,835,978)	(1,003,217)	(423,924)	(244,210)	(162,241)	(1,567)	(820)
33	378-MEAS. & REG. EQUIP-GEN	PLT378	657,026	359,013	151,706	87,393	58,060	561	293
34	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	PLT378	(28,040)	(15,322)	(6,474)	(3,730)	(2,478)	(24)	(13)
35	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	485,438	265,254	112,087	64,570	42,897	414	217
36	379-MEAS & REG EQ-CITY GATE - ACQ ADJ	PLT379	(28,168)	(15,391)	(6,504)	(3,747)	(2,489)	(24)	(13)
37	380-SERVICES	PLT380	26,830,743	24,506,549	2,117,957	5,444	199,865	0	928
38	380-SERVICES - ACQ ADJ	PLT380	(937,682)	(856,456)	(74,018)	(190)	(6,985)	0	(32)
39	381-METERS	PLT381	6,164,614	5,585,163	505,765	20,187	53,287	0	212
40	381-METERS - ACQ ADJ	PLT381	(116,507)	(105,556)	(9,559)	(382)	(1,007)	0	(4)
41	382-METER INSTALLATIONS	PLT382	1,826,540	1,654,852	149,855	5,981	15,789	0	63
42	382-METER INSTALLATIONS - ACQ ADJ	PLT382	(88,125)	(79,841)	(7,230)	(289)	(762)	0	(3)
43									
44									
45									

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
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		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	DEVELOPMENT OF RATE BASE CONT.							
2								
3	**DEPRECIATION RESERVE CONTINUED**							
4								
5	**DEPRECIATION RESERVE**							
6	INTANGIBLE RESERVE							
7	302-FRANCHISES & CONSENTS	PLT302	20,770	1,575	219	6,600	3,132	2,311
8	302-FRANCHISES & CONSENTS - ACQ ADJ	PLT302	(789)	(60)	(8)	(251)	(119)	(88)
9	303-MISC. INTANGIBLE PLANT	PLT303	32,515	2,466	343	10,332	4,903	3,618
10	303-MISC. INTANGIBLE PLANT - ACQ ADJ	PLT303	(826)	(63)	(9)	(262)	(125)	(92)
11	TOTAL INTANGIBLE PLANT		51,670	3,919	545	16,419	7,791	5,750
12								
13	TRANSMISSION RESERVE							
14	365-LAND & LAND RIGHTS	PLT365	3,115	408	62	1,968	669	680
15	365-LAND & LAND RIGHTS - ACQ ADJ	PLT365	(25)	(3)	(1)	(16)	(5)	(6)
16	366-STRUCTURES & IMPROVEMENTS	PLT366	843	110	17	533	181	184
17	366-STRUCTURES & IMPROV - ADQ ADJ	PLT366	(155)	(20)	(3)	(98)	(33)	(34)
18	367-MAINS	PLT367	749,357	98,195	14,851	473,399	160,864	163,503
19	367-MAINS - ACQ ADJ	PLT367	(25,327)	(3,319)	(502)	(16,000)	(5,437)	(5,526)
20	369-MEASURING & REG STATION EQUIP.	PLT369	65,004	8,518	1,288	41,066	13,954	14,183
21	369-MEASURING & REG STA EQ - ACQ ADJ	PLT369	(6,791)	(890)	(135)	(4,290)	(1,458)	(1,482)
22	371-OTHER EQUIPMENT	PLT371	0	0	0	0	0	0
23	371-OTHER EQUIPMENT - ACQ ADJ	PLT371	(1,136)	(149)	(23)	(718)	(244)	(248)
24	TOTAL TRANSMISSION PLANT		784,886	102,851	15,555	495,843	168,491	171,255
25								
26	DISTRIBUTION RESERVE							
27	374.1-LAND	PLT374	6,494	851	129	4,102	1,394	1,417
28	374.1-LAND - ACQ ADJ	PLT374	(37)	(5)	(1)	(24)	(8)	(8)
29	375-STRUCTURES & IMPROV	PLT375	1,435	188	28	906	308	313
30	375-STRUCTURES & IMPROV - ACQ ADJ	PLT375	(8)	(1)	(0)	(5)	(2)	(2)
31	376-MAINS	PLT376	7,659,869	1,003,745	151,801	4,839,042	1,644,344	1,671,319
32	376-MAINS - ACQ ADJ	PLT376	(374,809)	(49,115)	(7,428)	(236,782)	(80,460)	(81,780)
33	378-MEAS. & REG. EQUIP-GEN	PLT378	134,130	17,576	2,658	84,735	28,794	29,266
34	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	PLT378	(5,724)	(750)	(113)	(3,616)	(1,229)	(1,249)
35	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	99,101	12,986	1,964	62,606	21,274	21,623
36	379-MEAS & REG EQ-CITY GATE - ACQ ADJ	PLT379	(5,750)	(754)	(114)	(3,633)	(1,234)	(1,255)
37	380-SERVICES	PLT380	2,113,108	4,849	3,712	1,732	198,937	928
38	380-SERVICES - ACQ ADJ	PLT380	(73,849)	(169)	(130)	(61)	(6,952)	(32)
39	381-METERS	PLT381	481,588	24,177	846	19,341	45,339	7,948
40	381-METERS - ACQ ADJ	PLT381	(9,102)	(457)	(16)	(366)	(857)	(150)
41	382-METER INSTALLATIONS	PLT382	142,692	7,163	251	5,731	13,434	2,355
42	382-METER INSTALLATIONS - ACQ ADJ	PLT382	(6,884)	(346)	(12)	(276)	(648)	(114)
43								
44								
45								

UNS GAS COMPANY
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		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	DEVELOPMENT OF RATE BASE CONT.						
2							
3	**DEPRECIATION RESERVE CONTINUED**						
4							
5	**DEPRECIATION RESERVE**						
6	INTANGIBLE RESERVE						
7	302-FRANCHISES & CONSENTS	PLT302	142,516	7,954	20,770	591	984
8	302-FRANCHISES & CONSENTS - ACQ ADJ	PLT302	(5,412)	(302)	(789)	(22)	(37)
9	303-MISC. INTANGIBLE PLANT	PLT303	223,100	12,452	32,515	926	1,540
10	303-MISC. INTANGIBLE PLANT - ACQ ADJ	PLT303	(5,668)	(316)	(826)	(24)	(39)
11	TOTAL INTANGIBLE PLANT		354,537	19,787	51,670	1,471	2,447
12							
13	TRANSMISSION RESERVE						
14	365-LAND & LAND RIGHTS	PLT365	7,925	413	3,115	139	269
15	365-LAND & LAND RIGHTS - ACQ ADJ	PLT365	(65)	(3)	(25)	(1)	(2)
16	366-STRUCTURES & IMPROVEMENTS	PLT366	2,145	112	843	38	73
17	366-STRUCTURES & IMPROV - ADQ ADJ	PLT366	(394)	(21)	(155)	(7)	(13)
18	367-MAINS	PLT367	1,906,437	99,298	749,357	33,414	64,782
19	367-MAINS - ACQ ADJ	PLT367	(64,433)	(3,356)	(25,327)	(1,129)	(2,189)
20	369-MEASURING & REG STATION EQUIP.	PLT369	165,377	8,614	65,004	2,899	5,620
21	369-MEASURING & REG STA EQ - ACQ ADJ	PLT369	(17,277)	(900)	(6,791)	(303)	(587)
22	371-OTHER EQUIPMENT	PLT371	0	0	0	0	0
23	371-OTHER EQUIPMENT - ACQ ADJ	PLT371	(2,890)	(151)	(1,136)	(51)	(98)
24	TOTAL TRANSMISSION PLANT		1,996,825	104,006	784,886	34,998	67,853
25							
26	DISTRIBUTION RESERVE						
27	374.1-LAND	PLT374	16,521	860	6,494	290	561
28	374.1-LAND - ACQ ADJ	PLT374	(95)	(5)	(37)	(2)	(3)
29	375-STRUCTURES & IMPROV	PLT375	3,650	190	1,435	64	124
30	375-STRUCTURES & IMPROV - ACQ ADJ	PLT375	(20)	(1)	(8)	(0)	(1)
31	376-MAINS	PLT376	19,487,448	1,015,013	7,659,869	341,551	662,194
32	376-MAINS - ACQ ADJ	PLT376	(953,551)	(49,666)	(374,809)	(16,713)	(32,402)
33	378-MEAS. & REG. EQUIP-GEN	PLT378	341,240	17,774	134,130	5,981	11,596
34	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	PLT378	(14,563)	(759)	(5,724)	(255)	(495)
35	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	252,122	13,132	99,101	4,419	8,567
36	379-MEAS & REG EQ-CITY GATE - ACQ ADJ	PLT379	(14,630)	(762)	(5,750)	(256)	(497)
37	380-SERVICES	PLT380	23,193,025	1,313,524	2,113,108	4,849	0
38	380-SERVICES - ACQ ADJ	PLT380	(810,551)	(45,905)	(73,849)	(169)	0
39	381-METERS	PLT381	5,285,805	299,359	481,588	13,539	10,638
40	381-METERS - ACQ ADJ	PLT381	(99,899)	(5,658)	(9,102)	(256)	(201)
41	382-METER INSTALLATIONS	PLT382	1,566,154	88,698	142,692	4,012	3,152
42	382-METER INSTALLATIONS - ACQ ADJ	PLT382	(75,562)	(4,279)	(6,884)	(194)	(152)
43							
44							
45							

UNS GAS COMPANY
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		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	DEVELOPMENT OF RATE BASE CONT.				
2					
3	**DEPRECIATION RESERVE CONTINUED**				
4					
5	**DEPRECIATION RESERVE**				
6	INTANGIBLE RESERVE				
7	302-FRANCHISES & CONSENTS	PLT302	219	416	6,184
8	302-FRANCHISES & CONSENTS - ACQ ADJ	PLT302	(8)	(16)	(235)
9	303-MISC. INTANGIBLE PLANT	PLT303	343	652	9,680
10	303-MISC. INTANGIBLE PLANT - ACQ ADJ	PLT303	(9)	(17)	(246)
11	TOTAL INTANGIBLE PLANT		545	1,036	15,383
12					
13	TRANSMISSION RESERVE				
14	365-LAND & LAND RIGHTS	PLT365	62	113	1,855
15	365-LAND & LAND RIGHTS - ACQ ADJ	PLT365	(1)	(1)	(15)
16	366-STRUCTURES & IMPROVEMENTS	PLT366	17	30	502
17	366-STRUCTURES & IMPROV - ADQ ADJ	PLT366	(3)	(6)	(92)
18	367-MAINS	PLT367	14,851	27,105	446,294
19	367-MAINS - ACQ ADJ	PLT367	(502)	(916)	(15,084)
20	369-MEASURING & REG STATION EQUIP.	PLT369	1,288	2,351	38,714
21	369-MEASURING & REG STA EQ - ACQ ADJ	PLT369	(135)	(246)	(4,045)
22	371-OTHER EQUIPMENT	PLT371	0	0	0
23	371-OTHER EQUIPMENT - ACQ ADJ	PLT371	(23)	(41)	(677)
24	TOTAL TRANSMISSION PLANT		15,555	28,390	467,453
25					
26	DISTRIBUTION RESERVE				
27	374.1-LAND	PLT374	129	235	3,867
28	374.1-LAND - ACQ ADJ	PLT374	(1)	(1)	(22)
29	375-STRUCTURES & IMPROV	PLT375	28	52	854
30	375-STRUCTURES & IMPROV - ACQ ADJ	PLT375	(0)	(0)	(5)
31	376-MAINS	PLT376	151,801	277,065	4,561,977
32	376-MAINS - ACQ ADJ	PLT376	(7,428)	(13,557)	(223,225)
33	378-MEAS. & REG. EQUIP-GEN	PLT378	2,658	4,852	79,884
34	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	PLT378	(113)	(207)	(3,409)
35	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	1,964	3,585	59,021
36	379-MEAS & REG EQ-CITY GATE - ACQ ADJ	PLT379	(114)	(208)	(3,425)
37	380-SERVICES	PLT380	3,712	1,732	0
38	380-SERVICES - ACQ ADJ	PLT380	(130)	(61)	0
39	381-METERS	PLT381	846	4,835	14,506
40	381-METERS - ACQ ADJ	PLT381	(16)	(91)	(274)
41	382-METER INSTALLATIONS	PLT382	251	1,433	4,298
42	382-METER INSTALLATIONS - ACQ ADJ	PLT382	(12)	(69)	(207)
43					
44					
45					

UNS GAS COMPANY
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		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	DEVELOPMENT OF RATE BASE CONT.						
2							
3	**DEPRECIATION RESERVE CONTINUED**						
4							
5	**DEPRECIATION RESERVE**						
6	INTANGIBLE RESERVE						
7	302-FRANCHISES & CONSENTS	PLT302	3,132	435	1,877	42	27
8	302-FRANCHISES & CONSENTS - ACQ ADJ	PLT302	(119)	(16)	(71)	(2)	(1)
9	303-MISC. INTANGIBLE PLANT	PLT303	4,903	680	2,938	66	42
10	303-MISC. INTANGIBLE PLANT - ACQ ADJ	PLT303	(125)	(17)	(75)	(2)	(1)
11	TOTAL INTANGIBLE PLANT		7,791	1,081	4,669	106	67
12							
13	TRANSMISSION RESERVE						
14	365-LAND & LAND RIGHTS	PLT365	669	132	548	13	7
15	365-LAND & LAND RIGHTS - ACQ ADJ	PLT365	(5)	(1)	(4)	(0)	(0)
16	366-STRUCTURES & IMPROVEMENTS	PLT366	181	36	148	4	2
17	366-STRUCTURES & IMPROV - ADQ ADJ	PLT366	(33)	(7)	(27)	(1)	(0)
18	367-MAINS	PLT367	160,864	31,797	131,707	3,133	1,639
19	367-MAINS - ACQ ADJ	PLT367	(5,437)	(1,075)	(4,451)	(106)	(55)
20	369-MEASURING & REG STATION EQUIP.	PLT369	13,954	2,758	11,425	272	142
21	369-MEASURING & REG STA EQ - ACQ ADJ	PLT369	(1,458)	(288)	(1,194)	(28)	(15)
22	371-OTHER EQUIPMENT	PLT371	0	0	0	0	0
23	371-OTHER EQUIPMENT - ACQ ADJ	PLT371	(244)	(48)	(200)	(5)	(2)
24	TOTAL TRANSMISSION PLANT		168,491	33,304	137,951	3,281	1,717
25							
26	DISTRIBUTION RESERVE						
27	374.1-LAND	PLT374	1,394	276	1,141	27	14
28	374.1-LAND - ACQ ADJ	PLT374	(8)	(2)	(7)	(0)	(0)
29	375-STRUCTURES & IMPROV	PLT375	308	61	252	6	3
30	375-STRUCTURES & IMPROV - ACQ ADJ	PLT375	(2)	(0)	(1)	(0)	(0)
31	376-MAINS	PLT376	1,644,344	325,023	1,346,296	32,023	16,753
32	376-MAINS - ACQ ADJ	PLT376	(80,460)	(15,904)	(65,876)	(1,567)	(820)
33	378-MEAS. & REG. EQUIP-GEN	PLT378	28,794	5,691	23,575	561	293
34	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	PLT378	(1,229)	(243)	(1,006)	(24)	(13)
35	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	21,274	4,205	17,418	414	217
36	379-MEAS & REG EQ-CITY GATE - ACQ ADJ	PLT379	(1,234)	(244)	(1,011)	(24)	(13)
37	380-SERVICES	PLT380	198,937	928	0	0	928
38	380-SERVICES - ACQ ADJ	PLT380	(6,952)	(32)	0	0	(32)
39	381-METERS	PLT381	45,339	212	7,737	0	212
40	381-METERS - ACQ ADJ	PLT381	(857)	(4)	(146)	0	(4)
41	382-METER INSTALLATIONS	PLT382	13,434	63	2,292	0	63
42	382-METER INSTALLATIONS - ACQ ADJ	PLT382	(648)	(3)	(111)	0	(3)
43							
44							
45							

UNS GAS COMPANY
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		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	DEVELOPMENT OF RATE BASE CONT.								
2									
3	**DEPRECIATION RESERVE CONTINUED**								
4	DISTRIBUTION RESERVE CONTINUED								
5	383-REGULATORS	PLT383	1,048,907	965,643	83,264	0	0	0	0
6	383-REGULATORS - ACQ ADJ	PLT383	(22,959)	(21,136)	(1,823)	0	0	0	0
7	384-REGULATOR INSTALLATIONS	PLT384	190,999	175,837	15,162	0	0	0	0
8	384-REGULATOR INSTALLATIONS - ACQ ADJ	PLT384	(11,380)	(10,476)	(903)	0	0	0	0
9	385-INDUSTRIAL MEAS. EQUIP	PLT385	665,131	0	213,183	341,093	110,855	0	0
10	385-INDUSTRIAL MEAS. EQUIP - ACQ ADJ	PLT385	(13,537)	0	(4,339)	(6,942)	(2,256)	0	0
11	387-OTHER EQUIPMENT	PLT387	503,177	274,947	116,183	66,929	44,464	429	225
12	387-OTHER EQUIPMENT - ACQ ADJ	PLT387	(22,146)	(12,101)	(5,113)	(2,946)	(1,957)	(19)	(10)
13	TOTAL DISTRIBUTION RESERVE		72,828,026	52,191,322	11,597,804	5,325,143	3,664,118	31,827	17,813
14									
15	GENERAL PLANT RESERVE								
16	389-LAND AND LAND RIGHTS	PLT389	13,475	10,952	1,626	496	396	3	2
17	389-LAND AND LAND RIGHTS - ACQ ADJ	PLT389	(1,253)	(1,019)	(151)	(46)	(37)	(0)	(0)
18	390-STRUCTURES & IMPROVE	PLT390	284,256	231,016	34,307	10,469	8,357	65	41
19	390-STRUCTURES & IMPROVE - ACQ ADJ	PLT390	(23,370)	(18,993)	(2,821)	(861)	(687)	(5)	(3)
20	391-OFFICE FURN & EQUIPMENT	PLT391	1,461,457	1,187,734	176,385	53,825	42,966	335	211
21	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	PLT391	(392,983)	(319,380)	(47,430)	(14,474)	(11,553)	(90)	(57)
22	392-TRANSPORTATION EQUIP	PLT392	3,410,962	2,772,108	411,673	125,626	100,280	782	493
23	392-TRANSPORTATION EQUIP - ACQ ADJ	PLT392	(101,555)	(82,534)	(12,257)	(3,740)	(2,986)	(23)	(15)
24	393-STORES EQUIPMENT	PLT393	35,647	28,970	4,302	1,313	1,048	8	5
25	393-STORES EQUIPMENT - ACQ ADJ	PLT393	(2,606)	(2,118)	(315)	(96)	(77)	(1)	(0)
26	394-TOOLS, SHOP & GARAGE EQUIPMENT	PLT394	720,244	585,347	86,927	26,527	21,175	165	104
27	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	PLT394	(40,385)	(32,821)	(4,874)	(1,487)	(1,187)	(9)	(6)
28	395-LABORATORY EQUIPMENT	PLT395	330,922	268,942	39,939	12,188	9,729	76	48
29	395-LABORATORY EQUIPMENT - ACQ ADJ	PLT395	(36,929)	(30,012)	(4,457)	(1,360)	(1,086)	(8)	(5)
30	396-POWER OPERATED EQUIPMENT	PLT396	231,788	188,375	27,975	8,537	6,814	53	33
31	396-POWER OPERATED EQUIP - ACQ ADJ	PLT396	(1,490)	(1,211)	(180)	(55)	(44)	(0)	(0)
32	397-COMMUNICATION EQUIP	PLT397	542,215	440,661	65,441	19,970	15,941	124	78
33	397-COMMUNICATION EQUIP - ACQ ADJ	PLT397	(46,354)	(37,673)	(5,595)	(1,707)	(1,363)	(11)	(7)
34	398-MISCELLANEOUS EQUIP	PLT398	96,341	78,297	11,628	3,548	2,832	22	14
35	398-MISCELLANEOUS EQUIP - ACQ ADJ	PLT398	(5,811)	(4,722)	(701)	(214)	(171)	(1)	(1)
36	399-OTHER TANGIBLE PROPERTY	PLT399	0	0	0	0	0	0	0
37	TOTAL GENERAL PLANT RESERVE		6,474,571	5,261,921	781,424	238,458	190,348	1,484	936
38									
39	COMMON PLANT	PLTCOMN	0	0	0	0	0	0	0
40									
41	TOTAL DEPRECIATION RESERVE		83,607,897	59,928,398	13,322,554	6,091,962	4,207,753	36,698	20,532
42									
43	TOTAL DEPRECIATION RESERVE ACQ ADJ		(3,935,647)	(2,751,288)	(658,271)	(308,818)	(214,279)	(1,927)	(1,064)
44									
45	NET PLANT IN SERVICE		$203,909,989	$140,084,522	$35,131,228	$16,885,969	$11,644,650	$105,691	$57,929
46									

UNS GAS COMPANY
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		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	DEVELOPMENT OF RATE BASE CONT.							
2								
3	**DEPRECIATION RESERVE CONTINUED**							
4	DISTRIBUTION RESERVE CONTINUED							
5	383-REGULATORS	PLT383	83,264	0	0	0	0	0
6	383-REGULATORS - ACQ ADJ	PLT383	(1,823)	0	0	0	0	0
7	384-REGULATOR INSTALLATIONS	PLT384	15,162	0	0	0	0	0
8	384-REGULATOR INSTALLATIONS - ACQ ADJ	PLT384	(903)	0	0	0	0	0
9	385-INDUSTRIAL MEAS. EQUIP	PLT385	0	213,183	170,547	170,547	0	110,855
10	385-INDUSTRIAL MEAS. EQUIP - ACQ ADJ	PLT385	0	(4,339)	(3,471)	(3,471)	0	(2,256)
11	387-OTHER EQUIPMENT	PLT387	102,722	13,461	2,036	64,894	22,051	22,413
12	387-OTHER EQUIPMENT - ACQ ADJ	PLT387	(4,521)	(592)	(90)	(2,856)	(971)	(986)
13	TOTAL DISTRIBUTION RESERVE		10,356,152	1,241,651	322,596	5,002,546	1,883,513	1,780,605
14								
15	GENERAL PLANT RESERVE							
16	389-LAND AND LAND RIGHTS	PLT389	1,512	115	16	480	228	168
17	389-LAND AND LAND RIGHTS - ACQ ADJ	PLT389	(141)	(11)	(1)	(45)	(21)	(16)
18	390-STRUCTURES & IMPROVE	PLT390	31,889	2,418	336	10,133	4,809	3,548
19	390-STRUCTURES & IMPROVE - ACQ ADJ	PLT390	(2,622)	(199)	(28)	(833)	(395)	(292)
20	391-OFFICE FURN & EQUIPMENT	PLT391	163,951	12,434	1,729	52,097	24,722	18,244
21	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	PLT391	(44,086)	(3,344)	(465)	(14,009)	(6,648)	(4,906)
22	392-TRANSPORTATION EQUIP	PLT392	382,652	29,021	4,035	121,591	57,700	42,579
23	392-TRANSPORTATION EQUIP - ACQ ADJ	PLT392	(11,393)	(864)	(120)	(3,620)	(1,718)	(1,268)
24	393-STORES EQUIPMENT	PLT393	3,999	303	42	1,271	603	445
25	393-STORES EQUIPMENT - ACQ ADJ	PLT393	(292)	(22)	(3)	(93)	(44)	(33)
26	394-TOOLS, SHOP & GARAGE EQUIPMENT	PLT394	80,799	6,128	852	25,675	12,184	8,991
27	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	PLT394	(4,530)	(344)	(48)	(1,440)	(683)	(504)
28	395-LABORATORY EQUIPMENT	PLT395	37,124	2,816	391	11,796	5,598	4,131
29	395-LABORATORY EQUIPMENT - ACQ ADJ	PLT395	(4,143)	(314)	(44)	(1,316)	(625)	(461)
30	396-POWER OPERATED EQUIPMENT	PLT396	26,003	1,972	274	8,263	3,921	2,893
31	396-POWER OPERATED EQUIP - ACQ ADJ	PLT396	(167)	(13)	(2)	(53)	(25)	(19)
32	397-COMMUNICATION EQUIP	PLT397	60,827	4,613	641	19,328	9,172	6,769
33	397-COMMUNICATION EQUIP - ACQ ADJ	PLT397	(5,200)	(394)	(55)	(1,652)	(784)	(579)
34	398-MISCELLANEOUS EQUIP	PLT398	10,808	820	114	3,434	1,630	1,203
35	398-MISCELLANEOUS EQUIP - ACQ ADJ	PLT398	(652)	(49)	(7)	(207)	(98)	(73)
36	399-OTHER TANGIBLE PROPERTY	PLT399	0	0	0	0	0	0
37	TOTAL GENERAL PLANT RESERVE		726,338	55,086	7,659	230,800	109,525	80,823
38								
39	COMMON PLANT	PLTCOMN	0	0	0	0	0	0
40								
41	TOTAL DEPRECIATION RESERVE		11,919,046	1,403,507	346,354	5,745,608	2,169,321	2,038,433
42								
43	TOTAL DEPRECIATION RESERVE ACQ ADJ		(591,686)	(66,585)	(12,826)	(295,992)	(110,824)	(103,456)
44								
45	NET PLANT IN SERVICE		$31,524,289	$3,606,939	$684,675	$16,201,293	$5,990,649	$5,654,000
46								

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	DEVELOPMENT OF RATE BASE CONT.						
2							
3	**DEPRECIATION RESERVE CONTINUED**						
4	DISTRIBUTION RESERVE CONTINUED						
5	383-REGULATORS	PLT383	913,886	51,757	83,264	0	0
6	383-REGULATORS - ACQ ADJ	PLT383	(20,003)	(1,133)	(1,823)	0	0
7	384-REGULATOR INSTALLATIONS	PLT384	166,413	9,425	15,162	0	0
8	384-REGULATOR INSTALLATIONS - ACQ ADJ	PLT384	(9,915)	(562)	(903)	0	0
9	385-INDUSTRIAL MEAS. EQUIP	PLT385	0	0	0	119,383	93,801
10	385-INDUSTRIAL MEAS. EQUIP - ACQ ADJ	PLT385	0	0	0	(2,430)	(1,909)
11	387-OTHER EQUIPMENT	PLT387	261,335	13,612	102,722	4,580	8,880
12	387-OTHER EQUIPMENT - ACQ ADJ	PLT387	(11,502)	(599)	(4,521)	(202)	(391)
13	TOTAL DISTRIBUTION RESERVE		49,477,307	2,714,015	10,356,152	478,190	763,462
14							
15	GENERAL PLANT RESERVE						
16	389-LAND AND LAND RIGHTS	PLT389	10,373	579	1,512	43	72
17	389-LAND AND LAND RIGHTS - ACQ ADJ	PLT389	(965)	(54)	(141)	(4)	(7)
18	390-STRUCTURES & IMPROVE	PLT390	218,805	12,212	31,889	908	1,510
19	390-STRUCTURES & IMPROVE - ACQ ADJ	PLT390	(17,989)	(1,004)	(2,622)	(75)	(124)
20	391-OFFICE FURN & EQUIPMENT	PLT391	1,124,949	62,785	163,951	4,669	7,765
21	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	PLT391	(302,497)	(16,883)	(44,086)	(1,255)	(2,088)
22	392-TRANSPORTATION EQUIP	PLT392	2,625,572	146,537	382,652	10,897	18,124
23	392-TRANSPORTATION EQUIP - ACQ ADJ	PLT392	(78,172)	(4,363)	(11,393)	(324)	(540)
24	393-STORES EQUIPMENT	PLT393	27,439	1,531	3,999	114	189
25	393-STORES EQUIPMENT - ACQ ADJ	PLT393	(2,006)	(112)	(292)	(8)	(14)
26	394-TOOLS, SHOP & GARAGE EQUIPMENT	PLT394	554,405	30,942	80,799	2,301	3,827
27	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	PLT394	(31,086)	(1,735)	(4,530)	(129)	(215)
28	395-LABORATORY EQUIPMENT	PLT395	254,725	14,217	37,124	1,057	1,758
29	395-LABORATORY EQUIPMENT - ACQ ADJ	PLT395	(28,426)	(1,586)	(4,143)	(118)	(196)
30	396-POWER OPERATED EQUIPMENT	PLT396	178,418	9,958	26,003	740	1,232
31	396-POWER OPERATED EQUIP - ACQ ADJ	PLT396	(1,147)	(64)	(167)	(5)	(8)
32	397-COMMUNICATION EQUIP	PLT397	417,367	23,294	60,827	1,732	2,881
33	397-COMMUNICATION EQUIP - ACQ ADJ	PLT397	(35,681)	(1,991)	(5,200)	(148)	(246)
34	398-MISCELLANEOUS EQUIP	PLT398	74,158	4,139	10,808	308	512
35	398-MISCELLANEOUS EQUIP - ACQ ADJ	PLT398	(4,473)	(250)	(652)	(19)	(31)
36	399-OTHER TANGIBLE PROPERTY	PLT399	0	0	0	0	0
37	TOTAL GENERAL PLANT RESERVE		4,983,770	278,151	726,338	20,684	34,402
38							
39	COMMON PLANT	PLTCOMN	0	0	0	0	0
40							
41	TOTAL DEPRECIATION RESERVE		56,812,438	3,115,959	11,919,046	535,343	868,165
42							
43	TOTAL DEPRECIATION RESERVE ACQ ADJ		(2,608,869)	(142,419)	(591,686)	(24,099)	(42,486)
44							
45	NET PLANT IN SERVICE		$132,853,027	$7,231,495	$31,524,289	$1,296,392	$2,310,547
46							

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	DEVELOPMENT OF RATE BASE CONT.				
2					
3	**DEPRECIATION RESERVE CONTINUED**				
4	DISTRIBUTION RESERVE CONTINUED				
5	383-REGULATORS	PLT383	0	0	0
6	383-REGULATORS - ACQ ADJ	PLT383	0	0	0
7	384-REGULATOR INSTALLATIONS	PLT384	0	0	0
8	384-REGULATOR INSTALLATIONS - ACQ ADJ	PLT384	0	0	0
9	385-INDUSTRIAL MEAS. EQUIP	PLT385	170,547	42,637	127,910
10	385-INDUSTRIAL MEAS. EQUIP - ACQ ADJ	PLT385	(3,471)	(868)	(2,603)
11	387-OTHER EQUIPMENT	PLT387	2,036	3,716	61,178
12	387-OTHER EQUIPMENT - ACQ ADJ	PLT387	(90)	(164)	(2,693)
13	TOTAL DISTRIBUTION RESERVE		322,596	324,914	4,677,633
14					
15	GENERAL PLANT RESERVE				
16	389-LAND AND LAND RIGHTS	PLT389	16	30	450
17	389-LAND AND LAND RIGHTS - ACQ ADJ	PLT389	(1)	(3)	(42)
18	390-STRUCTURES & IMPROVE	PLT390	336	639	9,494
19	390-STRUCTURES & IMPROVE - ACQ ADJ	PLT390	(28)	(53)	(781)
20	391-OFFICE FURN & EQUIPMENT	PLT391	1,729	3,287	48,810
21	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	PLT391	(465)	(884)	(13,125)
22	392-TRANSPORTATION EQUIP	PLT392	4,035	7,672	113,919
23	392-TRANSPORTATION EQUIP - ACQ ADJ	PLT392	(120)	(228)	(3,392)
24	393-STORES EQUIPMENT	PLT393	42	80	1,191
25	393-STORES EQUIPMENT - ACQ ADJ	PLT393	(3)	(6)	(87)
26	394-TOOLS, SHOP & GARAGE EQUIPMENT	PLT394	852	1,620	24,055
27	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	PLT394	(48)	(91)	(1,349)
28	395-LABORATORY EQUIPMENT	PLT395	391	744	11,052
29	395-LABORATORY EQUIPMENT - ACQ ADJ	PLT395	(44)	(83)	(1,233)
30	396-POWER OPERATED EQUIPMENT	PLT396	274	521	7,741
31	396-POWER OPERATED EQUIP - ACQ ADJ	PLT396	(2)	(3)	(50)
32	397-COMMUNICATION EQUIP	PLT397	641	1,220	18,109
33	397-COMMUNICATION EQUIP - ACQ ADJ	PLT397	(55)	(104)	(1,548)
34	398-MISCELLANEOUS EQUIP	PLT398	114	217	3,218
35	398-MISCELLANEOUS EQUIP - ACQ ADJ	PLT398	(7)	(13)	(194)
36	399-OTHER TANGIBLE PROPERTY	PLT399	0	0	0
37	TOTAL GENERAL PLANT RESERVE		7,659	14,562	216,238
38					
39	COMMON PLANT	PLTCOMN	0	0	0
40					
41	TOTAL DEPRECIATION RESERVE		346,354	368,902	5,376,706
42					
43	TOTAL DEPRECIATION RESERVE ACQ ADJ		(12,826)	(17,936)	(278,056)
44					
45	NET PLANT IN SERVICE		$684,675	$974,812	$15,226,481
46					

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	DEVELOPMENT OF RATE BASE CONT.						
2							
3	**DEPRECIATION RESERVE CONTINUED**						
4	DISTRIBUTION RESERVE CONTINUED						
5	383-REGULATORS	PLT383	0	0	0	0	0
6	383-REGULATORS - ACQ ADJ	PLT383	0	0	0	0	0
7	384-REGULATOR INSTALLATIONS	PLT384	0	0	0	0	0
8	384-REGULATOR INSTALLATIONS - ACQ ADJ	PLT384	0	0	0	0	0
9	385-INDUSTRIAL MEAS. EQUIP	PLT385	0	42,637	68,219	0	0
10	385-INDUSTRIAL MEAS. EQUIP - ACQ ADJ	PLT385	0	(868)	(1,388)	0	0
11	387-OTHER EQUIPMENT	PLT387	22,051	4,359	18,054	429	225
12	387-OTHER EQUIPMENT - ACQ ADJ	PLT387	(971)	(192)	(795)	(19)	(10)
13	TOTAL DISTRIBUTION RESERVE		1,883,513	365,962	1,414,643	31,827	17,813
14							
15	GENERAL PLANT RESERVE						
16	389-LAND AND LAND RIGHTS	PLT389	228	32	137	3	2
17	389-LAND AND LAND RIGHTS - ACQ ADJ	PLT389	(21)	(3)	(13)	(0)	(0)
18	390-STRUCTURES & IMPROVE	PLT390	4,809	667	2,881	65	41
19	390-STRUCTURES & IMPROVE - ACQ ADJ	PLT390	(395)	(55)	(237)	(5)	(3)
20	391-OFFICE FURN & EQUIPMENT	PLT391	24,722	3,430	14,814	335	211
21	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	PLT391	(6,648)	(922)	(3,983)	(90)	(57)
22	392-TRANSPORTATION EQUIP	PLT392	57,700	8,005	34,575	782	493
23	392-TRANSPORTATION EQUIP - ACQ ADJ	PLT392	(1,718)	(238)	(1,029)	(23)	(15)
24	393-STORES EQUIPMENT	PLT393	603	84	361	8	5
25	393-STORES EQUIPMENT - ACQ ADJ	PLT393	(44)	(6)	(26)	(1)	(0)
26	394-TOOLS, SHOP & GARAGE EQUIPMENT	PLT394	12,184	1,690	7,301	165	104
27	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	PLT394	(683)	(95)	(409)	(9)	(6)
28	395-LABORATORY EQUIPMENT	PLT395	5,598	777	3,354	76	48
29	395-LABORATORY EQUIPMENT - ACQ ADJ	PLT395	(625)	(87)	(374)	(8)	(5)
30	396-POWER OPERATED EQUIPMENT	PLT396	3,921	544	2,349	53	33
31	396-POWER OPERATED EQUIP - ACQ ADJ	PLT396	(25)	(3)	(15)	(0)	(0)
32	397-COMMUNICATION EQUIP	PLT397	9,172	1,272	5,496	124	78
33	397-COMMUNICATION EQUIP - ACQ ADJ	PLT397	(784)	(109)	(470)	(11)	(7)
34	398-MISCELLANEOUS EQUIP	PLT398	1,630	226	977	22	14
35	398-MISCELLANEOUS EQUIP - ACQ ADJ	PLT398	(98)	(14)	(59)	(1)	(1)
36	399-OTHER TANGIBLE PROPERTY	PLT399	0	0	0	0	0
37	TOTAL GENERAL PLANT RESERVE		109,525	15,194	65,628	1,484	936
38							
39	COMMON PLANT	PLTCOMN	0	0	0	0	0
40							
41	TOTAL DEPRECIATION RESERVE		2,169,321	415,541	1,622,891	36,698	20,532
42							
43	TOTAL DEPRECIATION RESERVE ACQ ADJ		(110,824)	(20,476)	(82,980)	(1,927)	(1,064)
44							
45	NET PLANT IN SERVICE		$5,990,649	$1,118,585	$4,535,416	$105,691	$57,929
46							

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	DEVELOPMENT OF RATE BASE CONT.								
2									
3	**OTHER RATE BASE ITEMS**								
4									
5	WORKING CAPITAL								
6	CASH WORKING CAPITAL								
7	PLANT	PLANT	$1,568	$1,091	$264	$125	$86	$1	$0
8	COMMODITY	WCGC	0	0	0	0	0	0	0
9	OPERATIONS & MAINTENANCE	WCOTH	0	0	0	0	0	0	0
10	OTHER	WCOTH	0	0	0	0	0	0	0
11	TOTAL CASH WORKING CAPITAL		1,568	1,091	264	125	86	1	0
12	MATERIALS & SUPPLIES	PLANT	2,010,788	1,398,813	338,867	160,699	110,866	996	549
13	PREPAYMENTS	PLANT	352,564	245,263	59,416	28,176	19,439	175	96
14	TOTAL WORKING CAPITAL		2,364,921	1,645,166	398,547	189,000	130,391	1,171	645
15									
16	LESS: CUSTOMER CONTRIBUTIONS								
17	CUST ADVANCES FOR CONSTRUCTION	PLANT	(11,235,876)	(7,816,280)	(1,893,519)	(897,952)	(619,494)	(5,564)	(3,066)
18	CUSTOMER DEPOSITS	PLANT	(2,609,271)	(1,815,149)	(439,726)	(208,528)	(143,863)	(1,292)	(712)
19									
20	OTHER RATE BASE								
21	CWIP	DISTRPLT	0	0	0	0	0	0	0
22	Y2K COSTS & GIC DEF	PAYXAG	0	0	0	0	0	0	0
23	C.A.R.E.S.	THERMS	492,590	257,178	120,940	47,947	42,854	4,282	19,388
24	OTHER - WARM SPIRIT	RESNTPT	(22,372)	(22,372)	0	0	0	0	0
25	TOTAL OTHER		470,218	234,806	120,940	47,947	42,854	4,282	19,388
26									
27	LESS								
28	ACCUMULATED DEFERRED INC. TAXES	PLANT	(10,606,875)	(7,378,713)	(1,787,517)	(847,683)	(584,814)	(5,253)	(2,895)
29									
30									
31	TOTAL RATE BASE		$182,293,105	$124,954,351	$31,529,953	$15,168,753	$10,469,724	$99,034	$71,290
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	DEVELOPMENT OF RATE BASE CONT.							
2								
3	**OTHER RATE BASE ITEMS**							
4								
5	WORKING CAPITAL							
6	CASH WORKING CAPITAL							
7	PLANT	PLANT	$237	$27	$6	$120	$45	$42
8	COMMODITY	WCGC	0	0	0	0	0	0
9	OPERATIONS & MAINTENANCE	WCOTH	0	0	0	0	0	0
10	OTHER	WCOTH	0	0	0	0	0	0
11	TOTAL CASH WORKING CAPITAL		237	27	6	120	45	42
12	MATERIALS & SUPPLIES	PLANT	303,826	35,041	7,211	153,488	57,068	53,798
13	PREPAYMENTS	PLANT	53,272	6,144	1,264	26,912	10,006	9,433
14	TOTAL WORKING CAPITAL		357,334	41,212	8,481	180,520	67,118	63,273
15								
16	LESS: CUSTOMER CONTRIBUTIONS							
17	CUST ADVANCES FOR CONSTRUCTION	PLANT	(1,697,717)	(195,803)	(40,291)	(857,660)	(318,882)	(300,612)
18	CUSTOMER DEPOSITS	PLANT	(394,255)	(45,471)	(9,357)	(199,172)	(74,053)	(69,810)
19								
20	OTHER RATE BASE							
21	CWIP	DISTRPLT	0	0	0	0	0	0
22	Y2K COSTS & GIC DEF	PAYXAG	0	0	0	0	0	0
23	C.A.R.E.S.	THERMS	105,211	15,729	1,989	45,958	18,561	24,293
24	OTHER - WARM SPIRIT	RESNTPT	0	0	0	0	0	0
25	TOTAL OTHER		105,211	15,729	1,989	45,958	18,561	24,293
26								
27	LESS							
28	ACCUMULATED DEFERRED INC. TAXES	PLANT	(1,602,676)	(184,841)	(38,036)	(809,647)	(301,031)	(283,783)
29								
30								
31	TOTAL RATE BASE		$28,292,187	$3,237,766	$607,461	$14,561,293	$5,382,362	$5,087,362
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	DEVELOPMENT OF RATE BASE CONT.						
2							
3	**OTHER RATE BASE ITEMS**						
4							
5	WORKING CAPITAL						
6	CASH WORKING CAPITAL						
7	PLANT	PLANT	$1,034	$56	$237	$10	$17
8	COMMODITY	WCGC	0	0	0	0	0
9	OPERATIONS & MAINTENANCE	WCOTH	0	0	0	0	0
10	OTHER	WCOTH	0	0	0	0	0
11	TOTAL CASH WORKING CAPITAL		1,034	56	237	10	17
12	MATERIALS & SUPPLIES	PLANT	1,326,447	72,366	303,826	12,810	22,231
13	PREPAYMENTS	PLANT	232,574	12,688	53,272	2,246	3,898
14	TOTAL WORKING CAPITAL		1,560,055	85,111	357,334	15,067	26,146
15							
16	LESS: CUSTOMER CONTRIBUTIONS						
17	CUST ADVANCES FOR CONSTRUCTION	PLANT	(7,411,913)	(404,367)	(1,697,717)	(71,582)	(124,220)
18	CUSTOMER DEPOSITS	PLANT	(1,721,245)	(93,905)	(394,255)	(16,623)	(28,847)
19							
20	OTHER RATE BASE						
21	CWIP	DISTRPLT	0	0	0	0	0
22	Y2K COSTS & GIC DEF	PAYXAG	0	0	0	0	0
23	C.A.R.E.S.	THERMS	244,486	12,692	105,211	4,807	10,922
24	OTHER - WARM SPIRIT	RESNTPT	(21,217)	(1,155)	0	0	0
25	TOTAL OTHER		223,269	11,537	105,211	4,807	10,922
26							
27	LESS						
28	ACCUMULATED DEFERRED INC. TAXES	PLANT	(6,996,983)	(381,730)	(1,602,676)	(67,575)	(117,266)
29							
30							
31	TOTAL RATE BASE		$118,506,210	$6,448,141	$28,292,187	$1,160,485	$2,077,281
32							
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	DEVELOPMENT OF RATE BASE CONT.				
2					
3	**OTHER RATE BASE ITEMS**				
4					
5	WORKING CAPITAL				
6	CASH WORKING CAPITAL				
7	PLANT	PLANT	$6	$7	$112
8	COMMODITY	WCGC	0	0	0
9	OPERATIONS & MAINTENANCE	WCOTH	0	0	0
10	OTHER	WCOTH	0	0	0
11	TOTAL CASH WORKING CAPITAL		6	7	112
12	MATERIALS & SUPPLIES	PLANT	7,211	9,397	144,091
13	PREPAYMENTS	PLANT	1,264	1,648	25,264
14	TOTAL WORKING CAPITAL		8,481	11,052	169,467
15					
16	LESS: CUSTOMER CONTRIBUTIONS				
17	CUST ADVANCES FOR CONSTRUCTION	PLANT	(40,291)	(52,511)	(805,149)
18	CUSTOMER DEPOSITS	PLANT	(9,357)	(12,194)	(186,977)
19					
20	OTHER RATE BASE				
21	CWIP	DISTRPLT	0	0	0
22	Y2K COSTS & GIC DEF	PAYXAG	0	0	0
23	C.A.R.E.S.	THERMS	1,989	4,356	41,603
24	OTHER - WARM SPIRIT	RESNTPT	0	0	0
25	TOTAL OTHER		1,989	4,356	41,603
26					
27	LESS				
28	ACCUMULATED DEFERRED INC. TAXES	PLANT	(38,036)	(49,571)	(760,076)
29					
30					
31	TOTAL RATE BASE		$607,461	$875,944	$13,685,349
32					
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	DEVELOPMENT OF RATE BASE CONT.						
2							
3	**OTHER RATE BASE ITEMS**						
4							
5	WORKING CAPITAL						
6	CASH WORKING CAPITAL						
7	PLANT	PLANT	$45	$8	$34	$1	$0
8	COMMODITY	WCGC	0	0	0	0	0
9	OPERATIONS & MAINTENANCE	WCOTH	0	0	0	0	0
10	OTHER	WCOTH	0	0	0	0	0
11	TOTAL CASH WORKING CAPITAL		45	8	34	1	0
12	MATERIALS & SUPPLIES	PLANT	57,068	10,729	43,069	996	549
13	PREPAYMENTS	PLANT	10,006	1,881	7,552	175	96
14	TOTAL WORKING CAPITAL		67,118	12,619	50,654	1,171	645
15							
16	LESS: CUSTOMER CONTRIBUTIONS						
17	CUST ADVANCES FOR CONSTRUCTION	PLANT	(318,882)	(59,952)	(240,660)	(5,564)	(3,066)
18	CUSTOMER DEPOSITS	PLANT	(74,053)	(13,922)	(55,888)	(1,292)	(712)
19							
20	OTHER RATE BASE						
21	CWIP	DISTRPLT	0	0	0	0	0
22	Y2K COSTS & GIC DEF	PAYXAG	0	0	0	0	0
23	C.A.R.E.S.	THERMS	18,561	4,135	20,159	4,282	19,388
24	OTHER - WARM SPIRIT	RESNTPT	0	0	0	0	0
25	TOTAL OTHER		18,561	4,135	20,159	4,282	19,388
26							
27	LESS						
28	ACCUMULATED DEFERRED INC. TAXES	PLANT	(301,031)	(56,596)	(227,187)	(5,253)	(2,895)
29							
30							
31	TOTAL RATE BASE		$5,382,362	$1,004,868	$4,082,494	$99,034	$71,290
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	OPERATING REVENUES								
2									
3	**REVENUES**								
4									
5	GAS OPERATING REVENUES								
6									
7	SALES REVENUES								
8	FIRM SALES OF GAS		$51,157,764	$36,381,453	$10,351,444	$1,888,724	$2,435,339	$66,940	$33,865
9	INTERR SALES GAS COST REV	GASSALES	0	0	0	0	0	0	0
10	INTERR SALES PROFIT MARGINS	DEMGAS	0	0	0	0	0	0	0
11	INTERRUPTIBLE TRANSPORTATION	DISTR	0	0	0	0	0	0	0
12	SALES FOR RESALE	DEMGAS	0	0	0	0	0	0	0
13	TOTAL SALES OF GAS		51,157,764	36,381,453	10,351,444	1,888,724	2,435,339	66,940	33,865
14									
15	OTHER OPERATING REVENUES								
16	FORFEITED DISCOUNTS	PLANT	495,690	344,828	83,536	39,615	27,330	245	135
17	MISCELLANEOUS SERVICE REV	CUST487B	1,211,079	1,157,058	52,906	162	953	0	0
18	OTHER REVENUE	DEMGAS	37,974	23,258	9,949	574	2,052	387	1,753
19	OTHER REVENUE	PLANT	0	0	0	0	0	0	0
20	OTHER REVENUE	PLANT	0	0	0	0	0	0	0
21	TOTAL OTHER OPERATING REV		1,744,743	1,525,144	146,391	40,350	30,336	633	1,889
22									
23	TOTAL GAS OPERATING REVENUE		$52,902,507	$37,906,597	$10,497,835	$1,929,075	$2,465,675	$67,573	$35,753
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	OPERATING REVENUES							
2								
3	**REVENUES**							
4								
5	GAS OPERATING REVENUES							
6								
7	SALES REVENUES							
8	FIRM SALES OF GAS		$9,571,509	$779,934	$133,707	$1,755,017	$1,630,262	$805,077
9	INTERR SALES GAS COST REV	GASSALES	0	0	0	0	0	0
10	INTERR SALES PROFIT MARGINS	DEMGAS	0	0	0	0	0	0
11	INTERRUPTIBLE TRANSPORTATION	DISTR	0	0	0	0	0	0
12	SALES FOR RESALE	DEMGAS	0	0	0	0	0	0
13	TOTAL SALES OF GAS		9,571,509	779,934	133,707	1,755,017	1,630,262	805,077
14								
15	OTHER OPERATING REVENUES							
16	FORFEITED DISCOUNTS	PLANT	74,898	8,638	1,778	37,837	14,068	13,262
17	MISCELLANEOUS SERVICE REV	CUST487B	52,906	0	162	0	953	0
18	OTHER REVENUE	DEMGAS	9,515	435	180	394	1,679	374
19	OTHER REVENUE	PLANT	0	0	0	0	0	0
20	OTHER REVENUE	PLANT	0	0	0	0	0	0
21	TOTAL OTHER OPERATING REV		137,318	9,073	2,119	38,231	16,700	13,636
22								
23	TOTAL GAS OPERATING REVENUE		$9,708,828	$789,007	$135,827	$1,793,248	$1,646,961	$818,713
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL RESIDENTIAL SERVICE (14)	RESIDENTIAL CARES (15)	COMMERCIAL SM. VOL. (16)	COMMERCIAL LG. VOL. (17)	COMMERCIAL TRANS-PORTATION (18)
1	OPERATING REVENUES						
2							
3	**REVENUES**						
4							
5	GAS OPERATING REVENUES						
6							
7	SALES REVENUES						
8	FIRM SALES OF GAS		$35,003,749	$1,377,705	$9,571,509	$246,710	$533,224
9	INTERR SALES GAS COST REV	GASSALES	0	0	0	0	0
10	INTERR SALES PROFIT MARGINS	DEMGAS	0	0	0	0	0
11	INTERRUPTIBLE TRANSPORTATION	DISTR	0	0	0	0	0
12	SALES FOR RESALE	DEMGAS	0	0	0	0	0
13	TOTAL SALES OF GAS		35,003,749	1,377,705	9,571,509	246,710	533,224
14							
15	OTHER OPERATING REVENUES						
16	FORFEITED DISCOUNTS	PLANT	326,989	17,839	74,898	3,158	5,480
17	MISCELLANEOUS SERVICE REV	CUST487B	1,095,040	62,018	52,906	0	0
18	OTHER REVENUE	DEMGAS	22,110	1,148	9,515	435	0
19	OTHER REVENUE	PLANT	0	0	0	0	0
20	OTHER REVENUE	PLANT	0	0	0	0	0
21	TOTAL OTHER OPERATING REV		1,444,139	81,005	137,318	3,593	5,480
22							
23	TOTAL GAS OPERATING REVENUE		$36,447,887	$1,458,710	$9,708,828	$250,303	$538,704
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	OPERATING REVENUES				
2					
3	**REVENUES**				
4					
5	GAS OPERATING REVENUES				
6					
7	SALES REVENUES				
8	FIRM SALES OF GAS		$133,707	$121,445	$1,633,572
9	INTERR SALES GAS COST REV	GASSALES	0	0	0
10	INTERR SALES PROFIT MARGINS	DEMGAS	0	0	0
11	INTERRUPTIBLE TRANSPORTATION	DISTR	0	0	0
12	SALES FOR RESALE	DEMGAS	0	0	0
13	TOTAL SALES OF GAS		133,707	121,445	1,633,572
14					
15	OTHER OPERATING REVENUES				
16	FORFEITED DISCOUNTS	PLANT	1,778	2,317	35,521
17	MISCELLANEOUS SERVICE REV	CUST487B	162	0	0
18	OTHER REVENUE	DEMGAS	180	394	0
19	OTHER REVENUE	PLANT	0	0	0
20	OTHER REVENUE	PLANT	0	0	0
21	TOTAL OTHER OPERATING REV		2,119	2,711	35,521
22					
23	TOTAL GAS OPERATING REVENUE		$135,827	$124,155	$1,669,093
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	OPERATING REVENUES						
2							
3	**REVENUES**						
4							
5	GAS OPERATING REVENUES						
6							
7	SALES REVENUES						
8	FIRM SALES OF GAS		$1,630,262	$148,817	$656,260	$66,940	$33,865
9	INTERR SALES GAS COST REV	GASSALES	0	0	0	0	0
10	INTERR SALES PROFIT MARGINS	DEMGAS	0	0	0	0	0
11	INTERRUPTIBLE TRANSPORTATION	DISTR	0	0	0	0	0
12	SALES FOR RESALE	DEMGAS	0	0	0	0	0
13	TOTAL SALES OF GAS		1,630,262	148,817	656,260	66,940	33,865
14							
15	OTHER OPERATING REVENUES						
16	FORFEITED DISCOUNTS	PLANT	14,068	2,645	10,617	245	135
17	MISCELLANEOUS SERVICE REV	CUST487B	953	0	0	0	0
18	OTHER REVENUE	DEMGAS	1,679	374	0	387	1,753
19	OTHER REVENUE	PLANT	0	0	0	0	0
20	OTHER REVENUE	PLANT	0	0	0	0	0
21	TOTAL OTHER OPERATING REV		16,700	3,019	10,617	633	1,889
22							
23	TOTAL GAS OPERATING REVENUE		$1,646,961	$151,836	$666,877	$67,573	$35,753
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	OPERATION & MAINTENANCE EXPENSE								
2									
3	**OPERATION & MAINTENANCE EXPENSE**								
4	PRODUCTION EXPENSE								
5	421-PURCHASED POWER	DEMGAS	0	0	0	0	0	0	0
6	805-PURCHASED GAS EXPENSES	DEMGAS	0	0	0	0	0	0	0
7	807-PURCHASED GAS COST EXPENSES								
8	NON-RECONCILABLE	DEMGAS	397,635	243,538	104,183	6,008	21,492	4,055	18,360
9	CAPACITY RELATED	DEMGAS	0	0	0	0	0	0	0
10	COMMODITY RELATED	GASSALES	0	0	0	0	0	0	0
11	TOTAL ACCOUNT 807		397,635	243,538	104,183	6,008	21,492	4,055	18,360
12	TOTAL PURCHASED GAS SUPPLY		397,635	243,538	104,183	6,008	21,492	4,055	18,360
13									
14	TRANSMISSION EXPENSE								
15	856-MAINS EXPENSE	TRANS	14,172	7,744	3,272	1,885	1,252	12	6
16	857-MEASURING & REG. STATION	TRANS	0	0	0	0	0	0	0
17	864-MAINTENANCE OF COMPRESSOR STATION EC	TRANS	0	0	0	0	0	0	0
18	870-OPERATION SUPERVISION AND ENGINEERING	TRANS	349,645	191,053	80,732	46,507	30,897	298	156
19	TOTAL TRANSMISSION		363,817	198,797	84,005	48,393	32,150	311	162
20									
21	DISTRIBUTION EXPENSE								
22	431-INTEREST ON CUSTOMER DEPOSITS	LABDO	137,200	109,159	17,541	5,916	4,526	36	22
23	871-LOAD DISPATCHING	DISTR	0	0	0	0	0	0	0
24	874-MAINS & SERVICING EXPENSE	PLT376380	1,540,668	1,047,585	270,541	130,470	90,778	836	457
25	875-MEAS./REG. STATION EXPENSE	PLT378	229,538	125,424	53,000	30,532	20,284	196	102
26	876-MEAS./REG. STATION EXPENSE	PLT379	188,393	102,942	43,500	25,059	16,648	161	84
27	877-MEAS./REG. STATION EXPENSE	PLT383	28,503	26,240	2,263	0	0	0	0
28	878-METER EXPENSE	PLT381	1,485,403	1,345,781	121,867	4,864	12,840	0	51
29	879-CUSTOMER INSTALL EXP	PLT38284	798,365	724,940	65,206	2,252	5,944	0	24
30	880-OTHER EXPENSES	EXP87479	1,991,424	1,572,724	259,427	90,074	68,307	556	335
31	881-RENTS	DISTR	12,217	6,676	2,821	1,625	1,080	10	5
32	885-MAINT. SUPERV. & ENG.	LABDM	241,622	174,459	38,222	16,793	11,981	107	60
33	886-MAINT. OF STRUCTURES	PLT375	973,099	531,722	224,687	129,435	85,990	831	434
34	887-MAINT. OF MAINS	PLT376	143	78	33	19	13	0	0
35	889-MAINT. MEAS./REG	PLT378	32,400	17,704	7,481	4,310	2,863	28	14
36	890-MAINT. MEAS./REG	PLT379	10,950	5,983	2,528	1,456	968	9	5
37	891-MAINT. MEAS./REG	PLT383	2,845	2,619	226	0	0	0	0
38	892-MAINT. OF SERVICES	PLT380	586,448	535,647	46,293	119	4,369	0	20
39	893-MAINT. OF METER	PLT381	333,085	301,776	27,327	1,091	2,879	0	11
40	894-MAINT. OF OTHER EQUIP.	PLT387	53,271	29,109	12,300	7,086	4,707	45	24
41	TOTAL DISTRIBUTION EXP		8,645,572	6,660,568	1,195,262	451,100	334,175	2,816	1,650
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	OPERATION & MAINTENANCE EXPENSE							
2								
3	**OPERATION & MAINTENANCE EXPENSE**							
4	PRODUCTION EXPENSE							
5	421-PURCHASED POWER	DEMGAS	0	0	0	0	0	0
6	805-PURCHASED GAS EXPENSES	DEMGAS	0	0	0	0	0	0
7	807-PURCHASED GAS COST EXPENSES							
8	NON-RECONCILABLE	DEMGAS	99,631	4,552	1,884	4,125	17,577	3,915
9	CAPACITY RELATED	DEMGAS	0	0	0	0	0	0
10	COMMODITY RELATED	GASSALES	0	0	0	0	0	0
11	TOTAL ACCOUNT 807		99,631	4,552	1,884	4,125	17,577	3,915
12	TOTAL PURCHASED GAS SUPPLY		99,631	4,552	1,884	4,125	17,577	3,915
13								
14	TRANSMISSION EXPENSE							
15	856-MAINS EXPENSE	TRANS	2,893	379	57	1,828	621	631
16	857-MEASURING & REG. STATION	TRANS	0	0	0	0	0	0
17	864-MAINTENANCE OF COMPRESSOR STATION EC	TRANS	0	0	0	0	0	0
18	870-OPERATION SUPERVISION AND ENGINEERING	TRANS	71,379	9,353	1,415	45,093	15,323	15,574
19	TOTAL TRANSMISSION		74,272	9,733	1,472	46,921	15,944	16,206
20								
21	DISTRIBUTION EXPENSE							
22	431-INTEREST ON CUSTOMER DEPOSITS	LABDO	16,112	1,428	185	5,731	2,532	1,994
23	871-LOAD DISPATCHING	DISTR	0	0	0	0	0	0
24	874-MAINS & SERVICING EXPENSE	PLT376380	244,223	26,318	4,042	126,427	47,106	43,673
25	875-MEAS./REG. STATION EXPENSE	PLT378	46,859	6,140	929	29,603	10,059	10,224
26	876-MEAS./REG. STATION EXPENSE	PLT379	38,460	5,040	762	24,297	8,256	8,392
27	877-MEAS./REG. STATION EXPENSE	PLT383	2,263	0	0	0	0	0
28	878-METER EXPENSE	PLT381	116,042	5,826	204	4,660	10,925	1,915
29	879-CUSTOMER INSTALL EXP	PLT38284	62,509	2,697	94	2,157	5,057	887
30	880-OTHER EXPENSES	EXP87479	237,969	21,459	2,812	87,262	37,957	30,350
31	881-RENTS	DISTR	2,494	327	49	1,576	535	544
32	885-MAINT. SUPERV. & ENG.	LABDM	34,750	3,472	524	16,270	6,355	5,626
33	886-MAINT. OF STRUCTURES	PLT375	198,655	26,032	3,937	125,498	42,645	43,345
34	887-MAINT. OF MAINS	PLT376	29	4	1	19	6	6
35	889-MAINT. MEAS./REG	PLT378	6,614	867	131	4,179	1,420	1,443
36	890-MAINT. MEAS./REG	PLT379	2,235	293	44	1,412	480	488
37	891-MAINT. MEAS./REG	PLT383	226	0	0	0	0	0
38	892-MAINT. OF SERVICES	PLT380	46,187	106	81	38	4,348	20
39	893-MAINT. OF METER	PLT381	26,021	1,306	46	1,045	2,450	429
40	894-MAINT. OF OTHER EQUIP.	PLT387	10,875	1,425	216	6,870	2,335	2,373
41	TOTAL DISTRIBUTION EXP		1,092,524	102,739	14,057	437,043	182,466	151,709
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	OPERATION & MAINTENANCE EXPENSE						
2							
3	**OPERATION & MAINTENANCE EXPENSE**						
4	PRODUCTION EXPENSE						
5	421-PURCHASED POWER	DEMGAS	0	0	0	0	0
6	805-PURCHASED GAS EXPENSES	DEMGAS	0	0	0	0	0
7	807-PURCHASED GAS COST EXPENSES						
8	NON-RECONCILABLE	DEMGAS	231,519	12,018	99,631	4,552	0
9	CAPACITY RELATED	DEMGAS	0	0	0	0	0
10	COMMODITY RELATED	GASSALES	0	0	0	0	0
11	TOTAL ACCOUNT 807		231,519	12,018	99,631	4,552	0
12	TOTAL PURCHASED GAS SUPPLY		231,519	12,018	99,631	4,552	0
13							
14	TRANSMISSION EXPENSE						
15	856-MAINS EXPENSE	TRANS	7,361	383	2,893	129	250
16	857-MEASURING & REG. STATION	TRANS	0	0	0	0	0
17	864-MAINTENANCE OF COMPRESSOR STATION EC	TRANS	0	0	0	0	0
18	870-OPERATION SUPERVISION AND ENGINEERING	TRANS	181,595	9,458	71,379	3,183	6,171
19	TOTAL TRANSMISSION		188,956	9,842	74,272	3,312	6,421
20							
21	DISTRIBUTION EXPENSE						
22	431-INTEREST ON CUSTOMER DEPOSITS	LABDO	103,404	5,755	16,112	550	878
23	871-LOAD DISPATCHING	DISTR	0	0	0	0	0
24	874-MAINS & SERVICING EXPENSE	PLT376380	993,627	53,958	244,223	9,022	17,296
25	875-MEAS./REG. STATION EXPENSE	PLT378	119,215	6,209	46,859	2,089	4,051
26	876-MEAS./REG. STATION EXPENSE	PLT379	97,845	5,096	38,460	1,715	3,325
27	877-MEAS./REG. STATION EXPENSE	PLT383	24,834	1,406	2,263	0	0
28	878-METER EXPENSE	PLT381	1,273,648	72,132	116,042	3,262	2,563
29	879-CUSTOMER INSTALL EXP	PLT38284	686,084	38,856	62,509	1,510	1,187
30	880-OTHER EXPENSES	EXP87479	1,489,885	82,839	237,969	8,206	13,252
31	881-RENTS	DISTR	6,345	330	2,494	111	216
32	885-MAINT. SUPERV. & ENG.	LABDM	165,389	9,070	34,750	1,214	2,258
33	886-MAINT. OF STRUCTURES	PLT375	505,398	26,324	198,655	8,858	17,174
34	887-MAINT. OF MAINS	PLT376	75	4	29	1	3
35	889-MAINT. MEAS./REG	PLT378	16,828	876	6,614	295	572
36	890-MAINT. MEAS./REG	PLT379	5,687	296	2,235	100	193
37	891-MAINT. MEAS./REG	PLT383	2,479	140	226	0	0
38	892-MAINT. OF SERVICES	PLT380	506,937	28,710	46,187	106	0
39	893-MAINT. OF METER	PLT381	285,601	16,175	26,021	732	575
40	894-MAINT. OF OTHER EQUIP.	PLT387	27,668	1,441	10,875	485	940
41	TOTAL DISTRIBUTION EXP		6,310,948	349,620	1,092,524	38,257	64,482
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	OPERATION & MAINTENANCE EXPENSE				
2					
3	**OPERATION & MAINTENANCE EXPENSE**				
4	PRODUCTION EXPENSE				
5	421-PURCHASED POWER	DEMGAS	0	0	0
6	805-PURCHASED GAS EXPENSES	DEMGAS	0	0	0
7	807-PURCHASED GAS COST EXPENSES				
8	NON-RECONCILABLE	DEMGAS	1,884	4,125	0
9	CAPACITY RELATED	DEMGAS	0	0	0
10	COMMODITY RELATED	GASSALES	0	0	0
11	TOTAL ACCOUNT 807		1,884	4,125	0
12	TOTAL PURCHASED GAS SUPPLY		1,884	4,125	0
13					
14	TRANSMISSION EXPENSE				
15	856-MAINS EXPENSE	TRANS	57	105	1,723
16	857-MEASURING & REG. STATION	TRANS	0	0	0
17	864-MAINTENANCE OF COMPRESSOR STATION EC	TRANS	0	0	0
18	870-OPERATION SUPERVISION AND ENGINEERING	TRANS	1,415	2,582	42,511
19	TOTAL TRANSMISSION		1,472	2,686	44,234
20					
21	DISTRIBUTION EXPENSE				
22	431-INTEREST ON CUSTOMER DEPOSITS	LABDO	185	373	5,358
23	871-LOAD DISPATCHING	DISTR	0	0	0
24	874-MAINS & SERVICING EXPENSE	PLT376380	4,042	7,273	119,154
25	875-MEAS./REG. STATION EXPENSE	PLT378	929	1,695	27,908
26	876-MEAS./REG. STATION EXPENSE	PLT379	762	1,391	22,905
27	877-MEAS./REG. STATION EXPENSE	PLT383	0	0	0
28	878-METER EXPENSE	PLT381	204	1,165	3,495
29	879-CUSTOMER INSTALL EXP	PLT38284	94	539	1,618
30	880-OTHER EXPENSES	EXP87479	2,812	5,625	81,637
31	881-RENTS	DISTR	49	90	1,485
32	885-MAINT. SUPERV. & ENG.	LABDM	524	952	15,317
33	886-MAINT. OF STRUCTURES	PLT375	3,937	7,186	118,313
34	887-MAINT. OF MAINS	PLT376	1	1	17
35	889-MAINT. MEAS./REG	PLT378	131	239	3,939
36	890-MAINT. MEAS./REG	PLT379	44	81	1,331
37	891-MAINT. MEAS./REG	PLT383	0	0	0
38	892-MAINT. OF SERVICES	PLT380	81	38	0
39	893-MAINT. OF METER	PLT381	46	261	784
40	894-MAINT. OF OTHER EQUIP.	PLT387	216	393	6,477
41	TOTAL DISTRIBUTION EXP		14,057	27,303	409,740
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	OPERATION & MAINTENANCE EXPENSE						
2							
3	**OPERATION & MAINTENANCE EXPENSE**						
4	PRODUCTION EXPENSE						
5	421-PURCHASED POWER	DEMGAS	0	0	0	0	0
6	805-PURCHASED GAS EXPENSES	DEMGAS	0	0	0	0	0
7	807-PURCHASED GAS COST EXPENSES						
8	NON-RECONCILABLE	DEMGAS	17,577	3,915	0	4,055	18,360
9	CAPACITY RELATED	DEMGAS	0	0	0	0	0
10	COMMODITY RELATED	GASSALES	0	0	0	0	0
11	TOTAL ACCOUNT 807		17,577	3,915	0	4,055	18,360
12	TOTAL PURCHASED GAS SUPPLY		17,577	3,915	0	4,055	18,360
13							
14	TRANSMISSION EXPENSE						
15	856-MAINS EXPENSE	TRANS	621	123	509	12	6
16	857-MEASURING & REG. STATION	TRANS	0	0	0	0	0
17	864-MAINTENANCE OF COMPRESSOR STATION EC	TRANS	0	0	0	0	0
18	870-OPERATION SUPERVISION AND ENGINEERING	TRANS	15,323	3,029	12,546	298	156
19	TOTAL TRANSMISSION		15,944	3,152	13,054	311	162
20							
21	DISTRIBUTION EXPENSE						
22	431-INTEREST ON CUSTOMER DEPOSITS	LABDO	2,532	373	1,622	36	22
23	871-LOAD DISPATCHING	DISTR	0	0	0	0	0
24	874-MAINS & SERVICING EXPENSE	PLT376380	47,106	8,509	35,164	836	457
25	875-MEAS./REG. STATION EXPENSE	PLT378	10,059	1,988	8,236	196	102
26	876-MEAS./REG. STATION EXPENSE	PLT379	8,256	1,632	6,760	161	84
27	877-MEAS./REG. STATION EXPENSE	PLT383	0	0	0	0	0
28	878-METER EXPENSE	PLT381	10,925	51	1,864	0	51
29	879-CUSTOMER INSTALL EXP	PLT38284	5,057	24	863	0	24
30	880-OTHER EXPENSES	EXP87479	37,957	5,690	24,660	556	335
31	881-RENTS	DISTR	535	106	438	10	5
32	885-MAINT. SUPERV. & ENG.	LABDM	6,355	1,091	4,534	107	60
33	886-MAINT. OF STRUCTURES	PLT375	42,645	8,429	34,916	831	434
34	887-MAINT. OF MAINS	PLT376	6	1	5	0	0
35	889-MAINT. MEAS./REG	PLT378	1,420	281	1,163	28	14
36	890-MAINT. MEAS./REG	PLT379	480	95	393	9	5
37	891-MAINT. MEAS./REG	PLT383	0	0	0	0	0
38	892-MAINT. OF SERVICES	PLT380	4,348	20	0	0	20
39	893-MAINT. OF METER	PLT381	2,450	11	418	0	11
40	894-MAINT. OF OTHER EQUIP.	PLT387	2,335	461	1,911	45	24
41	TOTAL DISTRIBUTION EXP		182,466	28,763	122,947	2,816	1,650
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	OPERATION & MAINT EXP CONT.								
2									
3	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
4	CUSTOMER ACCOUNT								
5	901-SUPERVISION	LABCA	50,009	45,665	3,948	17	377	0	2
6	902-METER READING EXPENSE	CUST902	983,242	897,750	77,654	374	7,430	0	34
7	903-CUST RECORDS & COLLECT	CUST903	4,002,584	3,655,419	315,885	1,107	30,034	0	138
8	904-UNCOLLECTIBLE ACCOUNTS	BADDEBT	688,379	396,154	108,803	140,662	42,423	0	338
9	905-MISC CUST ACCTS EXP	EXP9024	20,265	17,676	1,794	508	285	0	2
10	906-CUSTOMER SERVICE & INFO	CUST10	0	0	0	0	0	0	0
11	907-SUPERV. CUSTOMER SERV.	LABCS	0	0	0	0	0	0	0
12	908-CUSTOMER ASSISTANCE	CUST10	69,987	63,919	5,523	18	521	2	4
13	909-INFO & INSTRUCTIONAL ADVERT.	CUST10	104,336	95,290	8,233	27	776	4	6
14	910-MISC. CUST. SERV. & INFO.	EXP9089	700	639	55	0	5	0	0
15	CARES DISCOUNTS	THERMS	0	0	0	0	0	0	0
16	CARES EXPENSES	THERMS	0	0	0	0	0	0	0
17	TOTAL CUSTOMER ACCTS EXP		5,919,503	5,172,512	521,896	142,715	81,851	6	524
18									
19	SALES EXPENSE								
20	912-DEMONSTRATING & SELLING	CDA912	0	0	0	0	0	0	0
21	913-ADVERTISING EXPENSES	CDA913	170	155	13	0	1	0	0
22	TOTAL SALES EXPENSE		170	155	13	0	1	0	0
23									
24	ADMINISTRATIVE & GENERAL EXPENSE								
25	920-ADMIN & GENERAL SALARY	PAYXAG	3,335,674	2,710,921	402,587	122,853	98,066	765	482
26	921-OFFICE SUPPLIES & EXP	PAYXAG	1,408,798	1,144,938	170,030	51,886	41,418	323	204
27	923-OUTSIDE SERV EMPLOYED	PAYXAG	(543,925)	(442,051)	(65,647)	(20,033)	(15,991)	(125)	(79)
28	924-PROPERTY INSURANCE	PAYXAG	934,046	759,104	112,731	34,401	27,460	214	135
29	925-INJURIES & DAMAGES	PAYXAG	11,505	9,350	1,388	424	338	3	2
30	926-EMPLOYED PENSION & BENF	PAYXAG	576,216	468,294	69,544	21,222	16,940	132	83
31	928-REGULATORY COMM EXPENSE	TOTREV	2,622,675	1,879,243	520,437	95,635	122,237	3,350	1,772
32	930-MISCELLANEOUS GEN EXP	PAYXAG	992,161	806,335	119,745	36,541	29,169	227	143
33	931-RENTS	PAYXAG	102,113	82,988	12,324	3,761	3,002	23	15
34	932-MAINT OF GENERAL PLT	GENPLT	350,787	285,087	42,337	12,919	10,313	80	51
35	TOTAL ADMIN & GEN EXPENSE		9,790,050	7,704,209	1,385,476	359,609	332,953	4,993	2,808
36									
37	TOTAL GAS O & M EXPENSE		$25,116,748	$19,979,779	$3,290,835	$1,007,825	$802,622	$12,181	$23,504
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	OPERATION & MAINT EXP CONT.							
2								
3	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							
4	CUSTOMER ACCOUNT							
5	901-SUPERVISION	LABCA	3,938	10	7	10	371	6
6	902-METER READING EXPENSE	CUST902	77,410	245	136	238	7,288	143
7	903-CUST RECORDS & COLLECT	CUST903	315,193	692	554	554	29,674	360
8	904-UNCOLLECTIBLE ACCOUNTS	BADDEBT	83,580	25,223	126	140,536	0	42,423
9	905-MISC CUST ACCTS EXP	EXP9024	1,701	93	3	505	132	153
10	906-CUSTOMER SERVICE & INFO	CUST10	0	0	0	0	0	0
11	907-SUPERV. CUSTOMER SERV.	LABCS	0	0	0	0	0	0
12	908-CUSTOMER ASSISTANCE	CUST10	5,512	11	10	9	1	519
13	909-INFO & INSTRUCTIONAL ADVERT.	CUST10	8,216	17	14	13	2	774
14	910-MISC. CUST. SERV. & INFO.	EXP9089	55	0	0	0	0	5
15	CARES DISCOUNTS	THERMS	0	0	0	0	0	0
16	CARES EXPENSES	THERMS	0	0	0	0	0	0
17	TOTAL CUSTOMER ACCTS EXP		495,604	26,291	850	141,865	37,468	44,384
18								
19	SALES EXPENSE							
20	912-DEMONSTRATING & SELLING	CDA912	0	0	0	0	0	0
21	913-ADVERTISING EXPENSES	CDA913	13	0	0	0	1	0
22	TOTAL SALES EXPENSE		13	0	0	0	1	0
23								
24	ADMINISTRATIVE & GENERAL EXPENSE							
25	920-ADMIN & GENERAL SALARY	PAYXAG	374,206	28,380	3,946	118,907	56,427	41,640
26	921-OFFICE SUPPLIES & EXP	PAYXAG	158,043	11,986	1,666	50,220	23,831	17,586
27	923-OUTSIDE SERV EMPLOYED	PAYXAG	(61,019)	(4,628)	(643)	(19,389)	(9,201)	(6,790)
28	924-PROPERTY INSURANCE	PAYXAG	104,784	7,947	1,105	33,296	15,800	11,660
29	925-INJURIES & DAMAGES	PAYXAG	1,291	98	14	410	195	144
30	926-EMPLOYED PENSION & BENF	PAYXAG	64,642	4,903	682	20,540	9,747	7,193
31	928-REGULATORY COMM EXPENSE	TOTREV	481,321	39,116	6,734	88,901	81,649	40,588
32	930-MISCELLANEOUS GEN EXP	PAYXAG	111,304	8,441	1,174	35,368	16,784	12,385
33	931-RENTS	PAYXAG	11,455	869	121	3,640	1,727	1,275
34	932-MAINT OF GENERAL PLT	GENPLT	39,352	2,985	415	12,505	5,934	4,379
35	TOTAL ADMIN & GEN EXPENSE		1,285,380	100,096	15,212	344,398	202,894	130,059
36								
37	TOTAL GAS O & M EXPENSE		$3,047,425	$243,411	$33,475	$974,351	$456,349	$346,273
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	OPERATION & MAINT EXP CONT.						
2							
3	**OPERATION & MAINTENANCE EXPENSE CONTINUED**						
4	CUSTOMER ACCOUNT						
5	901-SUPERVISION	LABCA	43,217	2,448	3,938	5	6
6	902-METER READING EXPENSE	CUST902	849,631	48,118	77,410	95	150
7	903-CUST RECORDS & COLLECT	CUST903	3,459,493	195,926	315,193	388	305
8	904-UNCOLLECTIBLE ACCOUNTS	BADDEBT	375,831	20,322	83,580	3,046	22,177
9	905-MISC CUST ACCTS EXP	EXP9024	16,732	944	1,701	13	81
10	906-CUSTOMER SERVICE & INFO	CUST10	0	0	0	0	0
11	907-SUPERV. CUSTOMER SERV.	LABCS	0	0	0	0	0
12	908-CUSTOMER ASSISTANCE	CUST10	60,493	3,426	5,512	7	4
13	909-INFO & INSTRUCTIONAL ADVERT.	CUST10	90,182	5,107	8,216	10	6
14	910-MISC. CUST. SERV. & INFO.	EXP9089	605	34	55	0	0
15	CARES DISCOUNTS	THERMS	0	0	0	0	0
16	CARES EXPENSES	THERMS	0	0	0	0	0
17	TOTAL CUSTOMER ACCTS EXP		4,896,185	276,327	495,604	3,563	22,729
18							
19	SALES EXPENSE						
20	912-DEMONSTRATING & SELLING	CDA912	0	0	0	0	0
21	913-ADVERTISING EXPENSES	CDA913	147	8	13	0	0
22	TOTAL SALES EXPENSE		147	8	13	0	0
23							
24	ADMINISTRATIVE & GENERAL EXPENSE						
25	920-ADMIN & GENERAL SALARY	PAYXAG	2,567,619	143,302	374,206	10,656	17,724
26	921-OFFICE SUPPLIES & EXP	PAYXAG	1,084,415	60,523	158,043	4,501	7,486
27	923-OUTSIDE SERV EMPLOYED	PAYXAG	(418,684)	(23,367)	(61,019)	(1,738)	(2,890)
28	924-PROPERTY INSURANCE	PAYXAG	718,977	40,127	104,784	2,984	4,963
29	925-INJURIES & DAMAGES	PAYXAG	8,856	494	1,291	37	61
30	926-EMPLOYED PENSION & BENF	PAYXAG	443,540	24,755	64,642	1,841	3,062
31	928-REGULATORY COMM EXPENSE	TOTREV	1,806,927	72,316	481,321	12,409	26,707
32	930-MISCELLANEOUS GEN EXP	PAYXAG	763,711	42,624	111,304	3,170	5,272
33	931-RENTS	PAYXAG	78,601	4,387	11,455	326	543
34	932-MAINT OF GENERAL PLT	GENPLT	270,017	15,070	39,352	1,121	1,864
35	TOTAL ADMIN & GEN EXPENSE		7,323,979	380,231	1,285,380	35,306	64,790
36							
37	TOTAL GAS O & M EXPENSE		$18,951,733	$1,028,046	$3,047,425	$84,990	$158,421
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	OPERATION & MAINT EXP CONT.				
2					
3	**OPERATION & MAINTENANCE EXPENSE CONTINUED**				
4	CUSTOMER ACCOUNT				
5	901-SUPERVISION	LABCA	7	2	9
6	902-METER READING EXPENSE	CUST902	136	34	204
7	903-CUST RECORDS & COLLECT	CUST903	554	138	415
8	904-UNCOLLECTIBLE ACCOUNTS	BADDEBT	126	189	140,347
9	905-MISC CUST ACCTS EXP	EXP9024	3	1	503
10	906-CUSTOMER SERVICE & INFO	CUST10	0	0	0
11	907-SUPERV. CUSTOMER SERV.	LABCS	0	0	0
12	908-CUSTOMER ASSISTANCE	CUST10	10	2	6
13	909-INFO & INSTRUCTIONAL ADVERT.	CUST10	14	4	9
14	910-MISC. CUST. SERV. & INFO.	EXP9089	0	0	0
15	CARES DISCOUNTS	THERMS	0	0	0
16	CARES EXPENSES	THERMS	0	0	0
17	TOTAL CUSTOMER ACCTS EXP		850	371	141,494
18					
19	SALES EXPENSE				
20	912-DEMONSTRATING & SELLING	CDA912	0	0	0
21	913-ADVERTISING EXPENSES	CDA913	0	0	0
22	TOTAL SALES EXPENSE		0	0	0
23					
24	ADMINISTRATIVE & GENERAL EXPENSE				
25	920-ADMIN & GENERAL SALARY	PAYXAG	3,946	7,502	111,405
26	921-OFFICE SUPPLIES & EXP	PAYXAG	1,666	3,169	47,051
27	923-OUTSIDE SERV EMPLOYED	PAYXAG	(643)	(1,223)	(18,166)
28	924-PROPERTY INSURANCE	PAYXAG	1,105	2,101	31,195
29	925-INJURIES & DAMAGES	PAYXAG	14	26	384
30	926-EMPLOYED PENSION & BENF	PAYXAG	682	1,296	19,244
31	928-REGULATORY COMM EXPENSE	TOTREV	6,734	6,155	82,746
32	930-MISCELLANEOUS GEN EXP	PAYXAG	1,174	2,231	33,136
33	931-RENTS	PAYXAG	121	230	3,410
34	932-MAINT OF GENERAL PLT	GENPLT	415	789	11,716
35	TOTAL ADMIN & GEN EXPENSE		15,212	22,275	322,122
36					
37	TOTAL GAS O & M EXPENSE		$33,475	$56,760	$917,590
38					
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	OPERATION & MAINT EXP CONT.						
2							
3	**OPERATION & MAINTENANCE EXPENSE CONTINUED**						
4	CUSTOMER ACCOUNT						
5	901-SUPERVISION	LABCA	371	2	4	0	2
6	902-METER READING EXPENSE	CUST902	7,288	34	109	0	34
7	903-CUST RECORDS & COLLECT	CUST903	29,674	138	221	0	138
8	904-UNCOLLECTIBLE ACCOUNTS	BADDEBT	0	0	42,423	0	338
9	905-MISC CUST ACCTS EXP	EXP9024	132	1	153	0	2
10	906-CUSTOMER SERVICE & INFO	CUST10	0	0	0	0	0
11	907-SUPERV. CUSTOMER SERV.	LABCS	0	0	0	0	0
12	908-CUSTOMER ASSISTANCE	CUST10	1	0	519	2	4
13	909-INFO & INSTRUCTIONAL ADVERT.	CUST10	2	1	774	4	6
14	910-MISC. CUST. SERV. & INFO.	EXP9089	0	0	5	0	0
15	CARES DISCOUNTS	THERMS	0	0	0	0	0
16	CARES EXPENSES	THERMS	0	0	0	0	0
17	TOTAL CUSTOMER ACCTS EXP		37,468	176	44,208	6	524
18							
19	SALES EXPENSE						
20	912-DEMONSTRATING & SELLING	CDA912	0	0	0	0	0
21	913-ADVERTISING EXPENSES	CDA913	1	0	0	0	0
22	TOTAL SALES EXPENSE		1	0	0	0	0
23							
24	ADMINISTRATIVE & GENERAL EXPENSE						
25	920-ADMIN & GENERAL SALARY	PAYXAG	56,427	7,828	33,811	765	482
26	921-OFFICE SUPPLIES & EXP	PAYXAG	23,831	3,306	14,280	323	204
27	923-OUTSIDE SERV EMPLOYED	PAYXAG	(9,201)	(1,276)	(5,513)	(125)	(79)
28	924-PROPERTY INSURANCE	PAYXAG	15,800	2,192	9,468	214	135
29	925-INJURIES & DAMAGES	PAYXAG	195	27	117	3	2
30	926-EMPLOYED PENSION & BENF	PAYXAG	9,747	1,352	5,841	132	83
31	928-REGULATORY COMM EXPENSE	TOTREV	81,649	7,527	33,061	3,350	1,772
32	930-MISCELLANEOUS GEN EXP	PAYXAG	16,784	2,328	10,057	227	143
33	931-RENTS	PAYXAG	1,727	240	1,035	23	15
34	932-MAINT OF GENERAL PLT	GENPLT	5,934	823	3,556	80	51
35	TOTAL ADMIN & GEN EXPENSE		202,894	24,348	105,712	4,993	2,808
36							
37	TOTAL GAS O & M EXPENSE		$456,349	$60,353	$285,920	$12,181	$23,504
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	DEPRECIATION & AMORT EXPENSE								
2									
3	**DEPRECIATION AND AMORITIZATION EXPENSE**								
4									
5	407-AMOR Y2K EXP; GPS & PRESC GAIN	PAYXAG	46,518	37,805	5,614	1,713	1,368	11	7
6	407-AMORTIZATION OF C.A.R.E.S.	PLANT	164,197	114,224	27,671	13,122	9,053	81	45
7									
8	INTANGIBLE PLT DEPRECIATION EXPENSE								
9	302-FRANCHISES & CONSENTS	PLT302	15,524	12,616	1,874	572	456	4	2
10	302-FRANCHISES & CONSENTS - ACQ ADJ	PLT302	(1,493)	(1,214)	(180)	(55)	(44)	(0)	(0)
11	303-MISC. INTANGIBLE PLANT	PLT303	1,214,673	987,172	146,600	44,736	35,710	278	176
12	303-MISC. INTANGIBLE PLANT - ACQ ADJ	PLT303	(2,049)	(1,665)	(247)	(75)	(60)	(0)	(0)
13	TOTAL INTANGIBLE PLT DEPR EXP		1,226,655	996,909	148,047	45,178	36,063	281	177
14									
15	TRANSMISSION PLT DEPR EXP								
16	365-LAND & LAND RIGHTS	PLT365	754	412	174	100	67	1	0
17	365-LAND & LAND RIGHTS - ACQ ADJ	PLT365	(129)	(70)	(30)	(17)	(11)	(0)	(0)
18	366-STRUCTURES & IMPROVEMENTS	PLT366	605	331	140	80	53	1	0
19	366-STRUCTURES & IMPROVE - ACQ ADJ	PLT366	(95)	(52)	(22)	(13)	(8)	(0)	(0)
20	367-MAINS	PLT367	313,477	171,290	72,381	41,697	27,701	268	140
21	367-MAINS - ACQ ADJ	PLT367	(25,713)	(14,050)	(5,937)	(3,420)	(2,272)	(22)	(11)
22	369-MEASURING & REG STATION EQ.	PLT369	51,161	27,956	11,813	6,805	4,521	44	23
23	369-MEASURING & REG STA EQ - ACQ ADJ	PLT369	(6,869)	(3,753)	(1,586)	(914)	(607)	(6)	(3)
24	371-OTHER EQUIPMENT	PLT371	0	0	0	0	0	0	0
25	371-OTHER EQUIPMENT - ACQ ADJ	PLT371	(883)	(482)	(204)	(117)	(78)	(1)	(0)
26	TOTAL TRANS PLT DEPR EXP		332,308	181,580	76,729	44,201	29,365	284	148
27									
28	DISTRIBUTION PLT DEPR EXP								
29	375-STRUCTURES & IMPROV	PLT375	1,294	707	299	172	114	1	1
30	375-STRUCTURES & IMPROV - ACQ ADJ	PLT375	(195)	(107)	(45)	(26)	(17)	(0)	(0)
31	376-MAINS	PLT376	3,218,602	1,758,712	743,169	428,117	284,419	2,747	1,437
32	376-MAINS - ACQ ADJ	PLT376	(380,982)	(208,177)	(87,968)	(50,676)	(33,666)	(325)	(170)
33	378-MEAS. & REG. EQUIP-GEN	PLT378	66,014	36,072	15,243	8,781	5,834	56	29
34	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	PLT378	(5,833)	(3,187)	(1,347)	(776)	(515)	(5)	(3)
35	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	63,591	34,747	14,683	8,458	5,619	54	28
36	379-MEAS. & REG. EQ-CITY GATE - ACQ ADJ	PLT379	(5,862)	(3,203)	(1,354)	(780)	(518)	(5)	(3)
37	380-SERVICES	PLT380	2,228,476	2,035,436	175,911	452	16,600	0	77
38	380-SERVICES - ACQ ADJ	PLT380	(195,164)	(178,258)	(15,406)	(40)	(1,454)	0	(7)
39	381-METERS	PLT381	250,749	227,179	20,572	821	2,167	0	9
40	381-METERS - ACQ ADJ	PLT381	(24,340)	(22,053)	(1,997)	(80)	(210)	0	(1)
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	DEPRECIATION & AMORT EXPENSE							
2								
3	**DEPRECIATION AND AMORITIZATION EXPENSE**							
4								
5	407-AMOR Y2K EXP; GPS & PRESC GAIN	PAYXAG	5,219	396	55	1,658	787	581
6	407-AMORTIZATION OF C.A.R.E.S.	PLANT	24,810	2,861	589	12,533	4,660	4,393
7								
8	INTANGIBLE PLT DEPRECIATION EXPENSE							
9	302-FRANCHISES & CONSENTS	PLT302	1,742	132	18	553	263	194
10	302-FRANCHISES & CONSENTS - ACQ ADJ	PLT302	(168)	(13)	(2)	(53)	(25)	(19)
11	303-MISC. INTANGIBLE PLANT	PLT303	136,266	10,335	1,437	43,300	20,548	15,163
12	303-MISC. INTANGIBLE PLANT - ACQ ADJ	PLT303	(230)	(17)	(2)	(73)	(35)	(26)
13	TOTAL INTANGIBLE PLT DEPR EXP		137,610	10,437	1,451	43,727	20,750	15,312
14								
15	TRANSMISSION PLT DEPR EXP							
16	365-LAND & LAND RIGHTS	PLT365	154	20	3	97	33	34
17	365-LAND & LAND RIGHTS - ACQ ADJ	PLT365	(26)	(3)	(1)	(17)	(6)	(6)
18	366-STRUCTURES & IMPROVEMENTS	PLT366	123	16	2	78	27	27
19	366-STRUCTURES & IMPROVE - ACQ ADJ	PLT366	(19)	(3)	(0)	(12)	(4)	(4)
20	367-MAINS	PLT367	63,995	8,386	1,268	40,428	13,738	13,963
21	367-MAINS - ACQ ADJ	PLT367	(5,249)	(688)	(104)	(3,316)	(1,127)	(1,145)
22	369-MEASURING & REG STATION EQ.	PLT369	10,444	1,369	207	6,598	2,242	2,279
23	369-MEASURING & REG STA EQ - ACQ ADJ	PLT369	(1,402)	(184)	(28)	(886)	(301)	(306)
24	371-OTHER EQUIPMENT	PLT371	0	0	0	0	0	0
25	371-OTHER EQUIPMENT - ACQ ADJ	PLT371	(180)	(24)	(4)	(114)	(39)	(39)
26	TOTAL TRANS PLT DEPR EXP		67,840	8,890	1,344	42,857	14,563	14,802
27								
28	DISTRIBUTION PLT DEPR EXP							
29	375-STRUCTURES & IMPROV	PLT375	264	35	5	167	57	58
30	375-STRUCTURES & IMPROV - ACQ ADJ	PLT375	(40)	(5)	(1)	(25)	(9)	(9)
31	376-MAINS	PLT376	657,068	86,102	13,022	415,096	141,053	143,367
32	376-MAINS - ACQ ADJ	PLT376	(77,776)	(10,192)	(1,541)	(49,134)	(16,696)	(16,970)
33	378-MEAS. & REG. EQUIP-GEN	PLT378	13,477	1,766	267	8,514	2,893	2,940
34	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	PLT378	(1,191)	(156)	(24)	(752)	(256)	(260)
35	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	12,982	1,701	257	8,201	2,787	2,833
36	379-MEAS. & REG. EQ-CITY GATE - ACQ ADJ	PLT379	(1,197)	(157)	(24)	(756)	(257)	(261)
37	380-SERVICES	PLT380	175,508	403	308	144	16,523	77
38	380-SERVICES - ACQ ADJ	PLT380	(15,371)	(35)	(27)	(13)	(1,447)	(7)
39	381-METERS	PLT381	19,589	983	34	787	1,844	323
40	381-METERS - ACQ ADJ	PLT381	(1,902)	(95)	(3)	(76)	(179)	(31)
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	DEPRECIATION & AMORT EXPENSE						
2							
3	**DEPRECIATION AND AMORITIZATION EXPENSE**						
4							
5	407-AMOR Y2K EXP; GPS & PRESC GAIN	PAYXAG	35,807	1,998	5,219	149	247
6	407-AMORTIZATION OF C.A.R.E.S.	PLANT	108,315	5,909	24,810	1,046	1,815
7							
8	INTANGIBLE PLT DEPRECIATION EXPENSE						
9	302-FRANCHISES & CONSENTS	PLT302	11,950	667	1,742	50	82
10	302-FRANCHISES & CONSENTS - ACQ ADJ	PLT302	(1,150)	(64)	(168)	(5)	(8)
11	303-MISC. INTANGIBLE PLANT	PLT303	934,989	52,183	136,266	3,880	6,454
12	303-MISC. INTANGIBLE PLANT - ACQ ADJ	PLT303	(1,577)	(88)	(230)	(7)	(11)
13	TOTAL INTANGIBLE PLT DEPR EXP		944,212	52,698	137,610	3,919	6,518
14							
15	TRANSMISSION PLT DEPR EXP						
16	365-LAND & LAND RIGHTS	PLT365	392	20	154	7	13
17	365-LAND & LAND RIGHTS - ACQ ADJ	PLT365	(67)	(3)	(26)	(1)	(2)
18	366-STRUCTURES & IMPROVEMENTS	PLT366	314	16	123	6	11
19	366-STRUCTURES & IMPROVE - ACQ ADJ	PLT366	(49)	(3)	(19)	(1)	(2)
20	367-MAINS	PLT367	162,810	8,480	63,995	2,854	5,532
21	367-MAINS - ACQ ADJ	PLT367	(13,355)	(696)	(5,249)	(234)	(454)
22	369-MEASURING & REG STATION EQ.	PLT369	26,572	1,384	10,444	466	903
23	369-MEASURING & REG STA EQ - ACQ ADJ	PLT369	(3,568)	(186)	(1,402)	(63)	(121)
24	371-OTHER EQUIPMENT	PLT371	0	0	0	0	0
25	371-OTHER EQUIPMENT - ACQ ADJ	PLT371	(458)	(24)	(180)	(8)	(16)
26	TOTAL TRANS PLT DEPR EXP		172,591	8,989	67,840	3,025	5,865
27							
28	DISTRIBUTION PLT DEPR EXP						
29	375-STRUCTURES & IMPROV	PLT375	672	35	264	12	23
30	375-STRUCTURES & IMPROV - ACQ ADJ	PLT375	(101)	(5)	(40)	(2)	(3)
31	376-MAINS	PLT376	1,671,644	87,068	657,068	29,298	56,803
32	376-MAINS - ACQ ADJ	PLT376	(197,870)	(10,306)	(77,776)	(3,468)	(6,724)
33	378-MEAS. & REG. EQUIP-GEN	PLT378	34,286	1,786	13,477	601	1,165
34	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	PLT378	(3,030)	(158)	(1,191)	(53)	(103)
35	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	33,027	1,720	12,982	579	1,122
36	379-MEAS. & REG. EQ-CITY GATE - ACQ ADJ	PLT379	(3,045)	(159)	(1,197)	(53)	(103)
37	380-SERVICES	PLT380	1,926,339	109,097	175,508	403	0
38	380-SERVICES - ACQ ADJ	PLT380	(168,704)	(9,554)	(15,371)	(35)	0
39	381-METERS	PLT381	215,003	12,177	19,589	551	433
40	381-METERS - ACQ ADJ	PLT381	(20,871)	(1,182)	(1,902)	(53)	(42)
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	DEPRECIATION & AMORT EXPENSE				
2					
3	**DEPRECIATION AND AMORITIZATION EXPENSE**				
4					
5	407-AMOR Y2K EXP; GPS & PRESC GAIN	PAYXAG	55	105	1,554
6	407-AMORTIZATION OF C.A.R.E.S.	PLANT	589	767	11,766
7					
8	INTANGIBLE PLT DEPRECIATION EXPENSE				
9	302-FRANCHISES & CONSENTS	PLT302	18	35	518
10	302-FRANCHISES & CONSENTS - ACQ ADJ	PLT302	(2)	(3)	(50)
11	303-MISC. INTANGIBLE PLANT	PLT303	1,437	2,732	40,568
12	303-MISC. INTANGIBLE PLANT - ACQ ADJ	PLT303	(2)	(5)	(68)
13	TOTAL INTANGIBLE PLT DEPR EXP		1,451	2,759	40,968
14					
15	TRANSMISSION PLT DEPR EXP				
16	365-LAND & LAND RIGHTS	PLT365	3	6	92
17	365-LAND & LAND RIGHTS - ACQ ADJ	PLT365	(1)	(1)	(16)
18	366-STRUCTURES & IMPROVEMENTS	PLT366	2	4	74
19	366-STRUCTURES & IMPROVE - ACQ ADJ	PLT366	(0)	(1)	(12)
20	367-MAINS	PLT367	1,268	2,315	38,114
21	367-MAINS - ACQ ADJ	PLT367	(104)	(190)	(3,126)
22	369-MEASURING & REG STATION EQ.	PLT369	207	378	6,220
23	369-MEASURING & REG STA EQ - ACQ ADJ	PLT369	(28)	(51)	(835)
24	371-OTHER EQUIPMENT	PLT371	0	0	0
25	371-OTHER EQUIPMENT - ACQ ADJ	PLT371	(4)	(7)	(107)
26	TOTAL TRANS PLT DEPR EXP		1,344	2,454	40,403
27					
28	DISTRIBUTION PLT DEPR EXP				
29	375-STRUCTURES & IMPROV	PLT375	5	10	157
30	375-STRUCTURES & IMPROV - ACQ ADJ	PLT375	(1)	(1)	(24)
31	376-MAINS	PLT376	13,022	23,767	391,329
32	376-MAINS - ACQ ADJ	PLT376	(1,541)	(2,813)	(46,321)
33	378-MEAS. & REG. EQUIP-GEN	PLT378	267	487	8,026
34	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	PLT378	(24)	(43)	(709)
35	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	257	470	7,732
36	379-MEAS. & REG. EQ-CITY GATE - ACQ ADJ	PLT379	(24)	(43)	(713)
37	380-SERVICES	PLT380	308	144	0
38	380-SERVICES - ACQ ADJ	PLT380	(27)	(13)	0
39	381-METERS	PLT381	34	197	590
40	381-METERS - ACQ ADJ	PLT381	(3)	(19)	(57)
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UNS GAS COMPANY
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		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	DEPRECIATION & AMORT EXPENSE						
2							
3	**DEPRECIATION AND AMORITIZATION EXPENSE**						
4							
5	407-AMOR Y2K EXP; GPS & PRESC GAIN	PAYXAG	787	109	472	11	7
6	407-AMORTIZATION OF C.A.R.E.S.	PLANT	4,660	876	3,517	81	45
7							
8	INTANGIBLE PLT DEPRECIATION EXPENSE						
9	302-FRANCHISES & CONSENTS	PLT302	263	36	157	4	2
10	302-FRANCHISES & CONSENTS - ACQ ADJ	PLT302	(25)	(4)	(15)	(0)	(0)
11	303-MISC. INTANGIBLE PLANT	PLT303	20,548	2,851	12,312	278	176
12	303-MISC. INTANGIBLE PLANT - ACQ ADJ	PLT303	(35)	(5)	(21)	(0)	(0)
13	TOTAL INTANGIBLE PLT DEPR EXP		20,750	2,879	12,434	281	177
14							
15	TRANSMISSION PLT DEPR EXP						
16	365-LAND & LAND RIGHTS	PLT365	33	7	27	1	0
17	365-LAND & LAND RIGHTS - ACQ ADJ	PLT365	(6)	(1)	(5)	(0)	(0)
18	366-STRUCTURES & IMPROVEMENTS	PLT366	27	5	22	1	0
19	366-STRUCTURES & IMPROVE - ACQ ADJ	PLT366	(4)	(1)	(3)	(0)	(0)
20	367-MAINS	PLT367	13,738	2,715	11,248	268	140
21	367-MAINS - ACQ ADJ	PLT367	(1,127)	(223)	(923)	(22)	(11)
22	369-MEASURING & REG STATION EQ.	PLT369	2,242	443	1,836	44	23
23	369-MEASURING & REG STA EQ - ACQ ADJ	PLT369	(301)	(60)	(246)	(6)	(3)
24	371-OTHER EQUIPMENT	PLT371	0	0	0	0	0
25	371-OTHER EQUIPMENT - ACQ ADJ	PLT371	(39)	(8)	(32)	(1)	(0)
26	TOTAL TRANS PLT DEPR EXP		14,563	2,879	11,923	284	148
27							
28	DISTRIBUTION PLT DEPR EXP						
29	375-STRUCTURES & IMPROV	PLT375	57	11	46	1	1
30	375-STRUCTURES & IMPROV - ACQ ADJ	PLT375	(9)	(2)	(7)	(0)	(0)
31	376-MAINS	PLT376	141,053	27,881	115,486	2,747	1,437
32	376-MAINS - ACQ ADJ	PLT376	(16,696)	(3,300)	(13,670)	(325)	(170)
33	378-MEAS. & REG. EQUIP-GEN	PLT378	2,893	572	2,369	56	29
34	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	PLT378	(256)	(51)	(209)	(5)	(3)
35	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	2,787	551	2,282	54	28
36	379-MEAS. & REG. EQ-CITY GATE - ACQ ADJ	PLT379	(257)	(51)	(210)	(5)	(3)
37	380-SERVICES	PLT380	16,523	77	0	0	77
38	380-SERVICES - ACQ ADJ	PLT380	(1,447)	(7)	0	0	(7)
39	381-METERS	PLT381	1,844	9	315	0	9
40	381-METERS - ACQ ADJ	PLT381	(179)	(1)	(31)	0	(1)
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	DEPREC & AMORT EXP CONT.								
2	DISTRIBUTION PLT DEPR EXP CONTINUED								
3	382-METER INSTALLATIONS	PLT382	185,804	168,339	15,244	608	1,606	0	6
4	382-METER INSTALLATIONS - ACQ ADJ	PLT382	(18,340)	(16,616)	(1,505)	(60)	(159)	0	(1)
5	383-REGULATORS	PLT383	67,574	62,210	5,364	0	0	0	0
6	383-REGULATORS - ACQ ADJ	PLT383	(4,774)	(4,395)	(379)	0	0	0	0
7	384-REGULATOR INSTALLATIONS	PLT384	34,830	32,065	2,765	0	0	0	0
8	384-REGULATOR INSTALLATIONS - ACQ ADJ	PLT384	(2,387)	(2,197)	(189)	0	0	0	0
9	385-INDUSTRIAL MEAS. EQUIP.	PLT385	20,338	0	6,519	10,430	3,390	0	0
10	385-INDUSTRIAL MEAS. EQUIP. - ACQ ADJ	PLT385	(2,924)	0	(937)	(1,500)	(487)	0	0
11	387-OTHER EQUIPMENT	PLT387	(12,250)	(6,694)	(2,829)	(1,629)	(1,083)	(10)	(5)
12	387-OTHER EQUIPMENT - ACQ ADJ	PLT387	(4,617)	(2,523)	(1,066)	(614)	(408)	(4)	(2)
13	TOTAL DISTRIBUTION PLT DEPR EXP		5,479,601	3,908,056	884,747	401,660	281,232	2,509	1,396
14									
15	GENERAL PLANT DEPR EXP								
16	390-STRUCTURES & IMPROVE	PLT390	211,692	172,043	25,549	7,797	6,224	49	31
17	390-STRUCTURES & IMPROVE - ACQ ADJ	PLT390	(6,895)	(5,604)	(832)	(254)	(203)	(2)	(1)
18	391-OFFICE FURN & EQUIPMENT	PLT391	613,706	498,762	74,069	22,603	18,042	141	89
19	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	PLT391	(97,872)	(79,541)	(11,812)	(3,605)	(2,877)	(22)	(14)
20	392-TRANSPORTATION EQUIP	PLT392	(17,941)	(14,581)	(2,165)	(661)	(527)	(4)	(3)
21	392-TRANSPORTATION EQUIP - ACQ ADJ	PLT392	0	0	0	0	0	0	0
22	393-STORES EQUIPMENT	PLT393	4,974	4,042	600	183	146	1	1
23	393-STORES EQUIPMENT - ACQ ADJ	PLT393	(537)	(436)	(65)	(20)	(16)	(0)	(0)
24	394-TOOLS, SHOP & GARAGE EQ	PLT394	78,999	64,203	9,535	2,910	2,323	18	11
25	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	PLT394	(9,163)	(7,447)	(1,106)	(337)	(269)	(2)	(1)
26	395-LABORATORY EQUIPMENT	PLT395	68,667	55,806	8,287	2,529	2,019	16	10
27	395-LABORATORY EQUIPMENT - ACQ ADJ	PLT395	(8,445)	(6,863)	(1,019)	(311)	(248)	(2)	(1)
28	396-POWER OPERATED EQUIPMENT	PLT396	91,483	74,349	11,041	3,369	2,690	21	13
29	396-POWER OPERATED EQUIP - ACQ ADJ	PLT396	(453)	(368)	(55)	(17)	(13)	(0)	(0)
30	397-COMMUNICATION EQUIP	PLT397	63,664	51,740	7,684	2,345	1,872	15	9
31	397-COMMUNICATION EQUIP - ACQ ADJ	PLT397	(10,194)	(8,285)	(1,230)	(375)	(300)	(2)	(1)
32	398-MISCELLANEOUS EQUIP	PLT398	10,264	8,342	1,239	378	302	2	1
33	398-MISCELLANEOUS EQUIP - ACQ ADJ	PLT398	(1,223)	(994)	(148)	(45)	(36)	(0)	(0)
34	399-OTHER TANGIBLE PROPERTY	PLT399	0	0	0	0	0	0	0
35	TOTAL GENERAL PLT DEPR EXP		990,727	805,170	119,572	36,488	29,127	227	143
36									
37	TOTAL DEPRECIATION & AMORTIZATION EXPENSE		$8,240,005	$6,043,745	$1,262,380	$542,363	$386,207	$3,393	$1,917
38									
39	TOTAL ACQUISITION ADJUSTMENT DEPR EXPENSE		(817,431)	(571,540)	(136,666)	(64,126)	(44,479)	(400)	(221)
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	DEPREC & AMORT EXP CONT.							
2	DISTRIBUTION PLT DEPR EXP CONTINUED							
3	382-METER INSTALLATIONS	PLT382	14,515	729	25	583	1,367	240
4	382-METER INSTALLATIONS - ACQ ADJ	PLT382	(1,433)	(72)	(3)	(58)	(135)	(24)
5	383-REGULATORS	PLT383	5,364	0	0	0	0	0
6	383-REGULATORS - ACQ ADJ	PLT383	(379)	0	0	0	0	0
7	384-REGULATOR INSTALLATIONS	PLT384	2,765	0	0	0	0	0
8	384-REGULATOR INSTALLATIONS - ACQ ADJ	PLT384	(189)	0	0	0	0	0
9	385-INDUSTRIAL MEAS. EQUIP.	PLT385	0	6,519	5,215	5,215	0	3,390
10	385-INDUSTRIAL MEAS. EQUIP. - ACQ ADJ	PLT385	0	(937)	(750)	(750)	0	(487)
11	387-OTHER EQUIPMENT	PLT387	(2,501)	(328)	(50)	(1,580)	(537)	(546)
12	387-OTHER EQUIPMENT - ACQ ADJ	PLT387	(943)	(124)	(19)	(595)	(202)	(206)
13	TOTAL DISTRIBUTION PLT DEPR EXP		798,611	86,136	16,694	384,966	146,806	134,427
14								
15	GENERAL PLANT DEPR EXP							
16	390-STRUCTURES & IMPROVE	PLT390	23,748	1,801	250	7,546	3,581	2,643
17	390-STRUCTURES & IMPROVE - ACQ ADJ	PLT390	(774)	(59)	(8)	(246)	(117)	(86)
18	391-OFFICE FURN & EQUIPMENT	PLT391	68,847	5,221	726	21,877	10,382	7,661
19	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	PLT391	(10,980)	(833)	(116)	(3,489)	(1,656)	(1,222)
20	392-TRANSPORTATION EQUIP	PLT392	(2,013)	(153)	(21)	(640)	(303)	(224)
21	392-TRANSPORTATION EQUIP - ACQ ADJ	PLT392	0	0	0	0	0	0
22	393-STORES EQUIPMENT	PLT393	558	42	6	177	84	62
23	393-STORES EQUIPMENT - ACQ ADJ	PLT393	(60)	(5)	(1)	(19)	(9)	(7)
24	394-TOOLS, SHOP & GARAGE EQ	PLT394	8,862	672	93	2,816	1,336	986
25	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	PLT394	(1,028)	(78)	(11)	(327)	(155)	(114)
26	395-LABORATORY EQUIPMENT	PLT395	7,703	584	81	2,448	1,162	857
27	395-LABORATORY EQUIPMENT - ACQ ADJ	PLT395	(947)	(72)	(10)	(301)	(143)	(105)
28	396-POWER OPERATED EQUIPMENT	PLT396	10,263	778	108	3,261	1,548	1,142
29	396-POWER OPERATED EQUIP - ACQ ADJ	PLT396	(51)	(4)	(1)	(16)	(8)	(6)
30	397-COMMUNICATION EQUIP	PLT397	7,142	542	75	2,269	1,077	795
31	397-COMMUNICATION EQUIP - ACQ ADJ	PLT397	(1,144)	(87)	(12)	(363)	(172)	(127)
32	398-MISCELLANEOUS EQUIP	PLT398	1,151	87	12	366	174	128
33	398-MISCELLANEOUS EQUIP - ACQ ADJ	PLT398	(137)	(10)	(1)	(44)	(21)	(15)
34	399-OTHER TANGIBLE PROPERTY	PLT399	0	0	0	0	0	0
35	TOTAL GENERAL PLT DEPR EXP		111,143	8,429	1,172	35,317	16,759	12,367
36								
37	TOTAL DEPRECIATION & AMORTIZATION EXPENSE		$1,145,232	$117,148	$21,305	$521,058	$204,325	$181,882
38								
39	TOTAL ACQUISITION ADJUSTMENT DEPR EXPENSE		(122,815)	(13,851)	(2,691)	(61,435)	(22,997)	(21,482)
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
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		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	DEPREC & AMORT EXP CONT.						
2	DISTRIBUTION PLT DEPR EXP CONTINUED						
3	382-METER INSTALLATIONS	PLT382	159,316	9,023	14,515	408	321
4	382-METER INSTALLATIONS - ACQ ADJ	PLT382	(15,725)	(891)	(1,433)	(40)	(32)
5	383-REGULATORS	PLT383	58,875	3,334	5,364	0	0
6	383-REGULATORS - ACQ ADJ	PLT383	(4,160)	(236)	(379)	0	0
7	384-REGULATOR INSTALLATIONS	PLT384	30,346	1,719	2,765	0	0
8	384-REGULATOR INSTALLATIONS - ACQ ADJ	PLT384	(2,079)	(118)	(189)	0	0
9	385-INDUSTRIAL MEAS. EQUIP.	PLT385	0	0	0	3,650	2,868
10	385-INDUSTRIAL MEAS. EQUIP. - ACQ ADJ	PLT385	0	0	0	(525)	(412)
11	387-OTHER EQUIPMENT	PLT387	(6,362)	(331)	(2,501)	(112)	(216)
12	387-OTHER EQUIPMENT - ACQ ADJ	PLT387	(2,398)	(125)	(943)	(42)	(81)
13	TOTAL DISTRIBUTION PLT DEPR EXP		3,705,162	202,894	798,611	31,118	55,018
14							
15	GENERAL PLANT DEPR EXP						
16	390-STRUCTURES & IMPROVE	PLT390	162,949	9,094	23,748	676	1,125
17	390-STRUCTURES & IMPROVE - ACQ ADJ	PLT390	(5,308)	(296)	(774)	(22)	(37)
18	391-OFFICE FURN & EQUIPMENT	PLT391	472,397	26,365	68,847	1,961	3,261
19	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	PLT391	(75,336)	(4,205)	(10,980)	(313)	(520)
20	392-TRANSPORTATION EQUIP	PLT392	(13,810)	(771)	(2,013)	(57)	(95)
21	392-TRANSPORTATION EQUIP - ACQ ADJ	PLT392	0	0	0	0	0
22	393-STORES EQUIPMENT	PLT393	3,829	214	558	16	26
23	393-STORES EQUIPMENT - ACQ ADJ	PLT393	(413)	(23)	(60)	(2)	(3)
24	394-TOOLS, SHOP & GARAGE EQ	PLT394	60,809	3,394	8,862	252	420
25	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	PLT394	(7,053)	(394)	(1,028)	(29)	(49)
26	395-LABORATORY EQUIPMENT	PLT395	52,856	2,950	7,703	219	365
27	395-LABORATORY EQUIPMENT - ACQ ADJ	PLT395	(6,500)	(363)	(947)	(27)	(45)
28	396-POWER OPERATED EQUIPMENT	PLT396	70,418	3,930	10,263	292	486
29	396-POWER OPERATED EQUIP - ACQ ADJ	PLT396	(349)	(19)	(51)	(1)	(2)
30	397-COMMUNICATION EQUIP	PLT397	49,005	2,735	7,142	203	338
31	397-COMMUNICATION EQUIP - ACQ ADJ	PLT397	(7,847)	(438)	(1,144)	(33)	(54)
32	398-MISCELLANEOUS EQUIP	PLT398	7,901	441	1,151	33	55
33	398-MISCELLANEOUS EQUIP - ACQ ADJ	PLT398	(941)	(53)	(137)	(4)	(6)
34	399-OTHER TANGIBLE PROPERTY	PLT399	0	0	0	0	0
35	TOTAL GENERAL PLT DEPR EXP		762,607	42,562	111,143	3,165	5,264
36							
37	TOTAL DEPRECIATION & AMORTIZATION EXPENSE		$5,728,693	$315,051	$1,145,232	$42,422	$74,727
38							
39	TOTAL ACQUISITION ADJUSTMENT DEPR EXPENSE		(541,953)	(29,587)	(122,815)	(5,021)	(8,831)
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
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		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	DEPREC & AMORT EXP CONT.				
2	DISTRIBUTION PLT DEPR EXP CONTINUED				
3	382-METER INSTALLATIONS	PLT382	25	146	437
4	382-METER INSTALLATIONS - ACQ ADJ	PLT382	(3)	(14)	(43)
5	383-REGULATORS	PLT383	0	0	0
6	383-REGULATORS - ACQ ADJ	PLT383	0	0	0
7	384-REGULATOR INSTALLATIONS	PLT384	0	0	0
8	384-REGULATOR INSTALLATIONS - ACQ ADJ	PLT384	0	0	0
9	385-INDUSTRIAL MEAS. EQUIP.	PLT385	5,215	1,304	3,911
10	385-INDUSTRIAL MEAS. EQUIP. - ACQ ADJ	PLT385	(750)	(187)	(562)
11	387-OTHER EQUIPMENT	PLT387	(50)	(90)	(1,489)
12	387-OTHER EQUIPMENT - ACQ ADJ	PLT387	(19)	(34)	(561)
13	TOTAL DISTRIBUTION PLT DEPR EXP		16,694	23,264	361,702
14					
15	GENERAL PLANT DEPR EXP				
16	390-STRUCTURES & IMPROVE	PLT390	250	476	7,070
17	390-STRUCTURES & IMPROVE - ACQ ADJ	PLT390	(8)	(16)	(230)
18	391-OFFICE FURN & EQUIPMENT	PLT391	726	1,380	20,497
19	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	PLT391	(116)	(220)	(3,269)
20	392-TRANSPORTATION EQUIP	PLT392	(21)	(40)	(599)
21	392-TRANSPORTATION EQUIP - ACQ ADJ	PLT392	0	0	0
22	393-STORES EQUIPMENT	PLT393	6	11	166
23	393-STORES EQUIPMENT - ACQ ADJ	PLT393	(1)	(1)	(18)
24	394-TOOLS, SHOP & GARAGE EQ	PLT394	93	178	2,638
25	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	PLT394	(11)	(21)	(306)
26	395-LABORATORY EQUIPMENT	PLT395	81	154	2,293
27	395-LABORATORY EQUIPMENT - ACQ ADJ	PLT395	(10)	(19)	(282)
28	396-POWER OPERATED EQUIPMENT	PLT396	108	206	3,055
29	396-POWER OPERATED EQUIP - ACQ ADJ	PLT396	(1)	(1)	(15)
30	397-COMMUNICATION EQUIP	PLT397	75	143	2,126
31	397-COMMUNICATION EQUIP - ACQ ADJ	PLT397	(12)	(23)	(340)
32	398-MISCELLANEOUS EQUIP	PLT398	12	23	343
33	398-MISCELLANEOUS EQUIP - ACQ ADJ	PLT398	(1)	(3)	(41)
34	399-OTHER TANGIBLE PROPERTY	PLT399	0	0	0
35	TOTAL GENERAL PLT DEPR EXP		1,172	2,228	33,088
36					
37	TOTAL DEPRECIATION & AMORTIZATION EXPENSE		$21,305	$31,577	$489,481
38					
39	TOTAL ACQUISITION ADJUSTMENT DEPR EXPENSE		(2,691)	(3,729)	(57,707)
40					
41					
42					
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44					
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	DEPREC & AMORT EXP CONT.						
2	DISTRIBUTION PLT DEPR EXP CONTINUED						
3	382-METER INSTALLATIONS	PLT382	1,367	6	233	0	6
4	382-METER INSTALLATIONS - ACQ ADJ	PLT382	(135)	(1)	(23)	0	(1)
5	383-REGULATORS	PLT383	0	0	0	0	0
6	383-REGULATORS - ACQ ADJ	PLT383	0	0	0	0	0
7	384-REGULATOR INSTALLATIONS	PLT384	0	0	0	0	0
8	384-REGULATOR INSTALLATIONS - ACQ ADJ	PLT384	0	0	0	0	0
9	385-INDUSTRIAL MEAS. EQUIP.	PLT385	0	1,304	2,086	0	0
10	385-INDUSTRIAL MEAS. EQUIP. - ACQ ADJ	PLT385	0	(187)	(300)	0	0
11	387-OTHER EQUIPMENT	PLT387	(537)	(106)	(440)	(10)	(5)
12	387-OTHER EQUIPMENT - ACQ ADJ	PLT387	(202)	(40)	(166)	(4)	(2)
13	TOTAL DISTRIBUTION PLT DEPR EXP		146,806	26,665	107,761	2,509	1,396
14							
15	GENERAL PLANT DEPR EXP						
16	390-STRUCTURES & IMPROVE	PLT390	3,581	497	2,146	49	31
17	390-STRUCTURES & IMPROVE - ACQ ADJ	PLT390	(117)	(16)	(70)	(2)	(1)
18	391-OFFICE FURN & EQUIPMENT	PLT391	10,382	1,440	6,221	141	89
19	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	PLT391	(1,656)	(230)	(992)	(22)	(14)
20	392-TRANSPORTATION EQUIP	PLT392	(303)	(42)	(182)	(4)	(3)
21	392-TRANSPORTATION EQUIP - ACQ ADJ	PLT392	0	0	0	0	0
22	393-STORES EQUIPMENT	PLT393	84	12	50	1	1
23	393-STORES EQUIPMENT - ACQ ADJ	PLT393	(9)	(1)	(5)	(0)	(0)
24	394-TOOLS, SHOP & GARAGE EQ	PLT394	1,336	185	801	18	11
25	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	PLT394	(155)	(22)	(93)	(2)	(1)
26	395-LABORATORY EQUIPMENT	PLT395	1,162	161	696	16	10
27	395-LABORATORY EQUIPMENT - ACQ ADJ	PLT395	(143)	(20)	(86)	(2)	(1)
28	396-POWER OPERATED EQUIPMENT	PLT396	1,548	215	927	21	13
29	396-POWER OPERATED EQUIP - ACQ ADJ	PLT396	(8)	(1)	(5)	(0)	(0)
30	397-COMMUNICATION EQUIP	PLT397	1,077	149	645	15	9
31	397-COMMUNICATION EQUIP - ACQ ADJ	PLT397	(172)	(24)	(103)	(2)	(1)
32	398-MISCELLANEOUS EQUIP	PLT398	174	24	104	2	1
33	398-MISCELLANEOUS EQUIP - ACQ ADJ	PLT398	(21)	(3)	(12)	(0)	(0)
34	399-OTHER TANGIBLE PROPERTY	PLT399	0	0	0	0	0
35	TOTAL GENERAL PLT DEPR EXP		16,759	2,325	10,042	227	143
36							
37	TOTAL DEPRECIATION & AMORTIZATION EXPENSE		$204,325	$35,733	$146,149	$3,393	$1,917
38							
39	TOTAL ACQUISITION ADJUSTMENT DEPR EXPENSE		(22,997)	(4,255)	(17,227)	(400)	(221)
40							
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	STATE & FED TAXES & OTHER EXPENSE								
2									
3	**TAXES OTHER THAN INCOME**								
4	PROPERTY TAXES - TRANSMISSION	TRANPLT	$217,294	$118,734	$50,173	$28,903	$19,202	$185	$97
5	PROPERTY TAXES - DISTRIBUTION	DISTRPLT	3,203,226	2,228,639	539,408	256,268	176,457	1,582	872
6	PROPERTY TAXES - GENERAL	GENPLT	189,559	154,056	22,878	6,981	5,573	43	27
7	PAYROLL TAXES	LABOR	560,124	455,216	67,602	20,629	16,467	128	81
8	OTHER TAXES	PLANT	171,875	119,566	28,965	13,736	9,476	85	47
9	TOTAL TAX OTHER THAN INCOME		4,342,079	3,076,211	709,027	326,518	227,175	2,024	1,124
10									
11	TOTAL OPERATING EXPENSE BEFORE INCOME TAX		$37,698,831	$29,099,735	$5,262,242	$1,876,706	$1,416,005	$17,598	$26,545
12	**FEDERAL & STATE TAX CALCULATION**								
13									
14	OPERATING REVENUES		$52,902,507	$37,906,597	$10,497,835	$1,929,075	$2,465,675	$67,573	$35,753
15	OPERATING EXPENSES								
16	OPERATION & MAINTENANCE EXP		25,116,748	19,979,779	3,290,835	1,007,825	802,622	12,181	23,504
17	DEPRECIATION		8,240,005	6,043,745	1,262,380	542,363	386,207	3,393	1,917
18	TAXES OTHER THAN INCOME		4,342,079	3,076,211	709,027	326,518	227,175	2,024	1,124
19	OPERATING INCOME BEFORE INCOME TAXES		15,203,676	8,806,862	5,235,593	52,368	1,049,670	49,975	9,208
20									
21	INTEREST EXPENSE		(5,821,563)	(3,990,440)	(1,006,915)	(484,417)	(334,353)	(3,163)	(2,277)
22									
23	BOOK TAXABLE INCOME		9,382,113	4,816,423	4,228,678	(432,049)	715,317	46,812	6,931
24									
25	STATE TAX @ 0.00%		0	0	0	0	0	0	0
26									
27	STATE AND FEDERAL TAXABLE BASIS		9,382,111	4,816,423	4,228,676	(432,049)	715,317	46,812	6,931
28									
29	STATE AND FEDERAL INCOME TAX @ 38.41%		3,603,671	1,849,989	1,624,236	(165,950)	274,754	17,980	2,662
30	AMORTIZATION OF ITC	PLANT	0	0	0	0	0	0	0
31	BLANK.	PLANT	0	0	0	0	0	0	0
32	TOTAL STATE AND FEDERAL TAXES		3,603,671	1,849,989	1,624,236	(165,950)	274,754	17,980	2,662
33									
34	TOTAL STATE & FEDERAL INCOME TAX		3,603,671	1,849,989	1,624,236	(165,950)	274,754	17,980	2,662
35									
36	NET INCOME AFTER TAX		$11,600,005	$6,956,873	$3,611,357	$218,318	$774,916	$31,994	$6,546
37									

UNS GAS COMPANY
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		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	STATE & FED TAXES & OTHER EXPENSE							
2								
3	**TAXES OTHER THAN INCOME**							
4	PROPERTY TAXES - TRANSMISSION	TRANPLT	$44,360	$5,813	$879	$28,024	$9,523	$9,679
5	PROPERTY TAXES - DISTRIBUTION	DISTRPLT	483,184	56,225	12,023	244,245	90,708	85,749
6	PROPERTY TAXES - GENERAL	GENPLT	21,265	1,613	224	6,757	3,207	2,366
7	PAYROLL TAXES	LABOR	62,836	4,766	663	19,967	9,475	6,992
8	OTHER TAXES	PLANT	25,970	2,995	616	13,120	4,878	4,598
9	TOTAL TAX OTHER THAN INCOME		637,615	71,411	14,406	312,113	117,790	109,385
10								
11	TOTAL OPERATING EXPENSE BEFORE INCOME TAX		$4,830,272	$431,970	$69,185	$1,807,521	$778,465	$637,540
12	**FEDERAL & STATE TAX CALCULATION**							
13								
14	OPERATING REVENUES		$9,708,828	$789,007	$135,827	$1,793,248	$1,646,961	$818,713
15	OPERATING EXPENSES							
16	OPERATION & MAINTENANCE EXP		3,047,425	243,411	33,475	974,351	456,349	346,273
17	DEPRECIATION		1,145,232	117,148	21,305	521,058	204,325	181,882
18	TAXES OTHER THAN INCOME		637,615	71,411	14,406	312,113	117,790	109,385
19	OPERATING INCOME BEFORE INCOME TAXES		4,878,556	357,037	66,642	(14,273)	868,497	181,173
20								
21	INTEREST EXPENSE		(903,516)	(103,399)	(19,399)	(465,017)	(171,887)	(162,466)
22								
23	BOOK TAXABLE INCOME		3,975,040	253,638	47,242	(479,291)	696,610	18,707
24								
25	STATE TAX @ 0.00%		0	0	0	0	0	0
26								
27	STATE AND FEDERAL TAXABLE BASIS		3,975,040	253,636	47,242	(479,291)	696,610	18,707
28								
29	STATE AND FEDERAL INCOME TAX @ 38.41%		1,526,814	97,422	18,146	(184,096)	267,568	7,185
30	AMORTIZATION OF ITC	PLANT	0	0	0	0	0	0
31	BLANK.	PLANT	0	0	0	0	0	0
32	TOTAL STATE AND FEDERAL TAXES		1,526,814	97,422	18,146	(184,096)	267,568	7,185
33								
34	TOTAL STATE & FEDERAL INCOME TAX		1,526,814	97,422	18,146	(184,096)	267,568	7,185
35								
36	NET INCOME AFTER TAX		$3,351,742	$259,615	$48,496	$169,822	$600,929	$173,988
37								

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
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		ALLOC	RESIDENTIAL RESIDENTIAL SERVICE (14)	RESIDENTIAL CARES (15)	COMMERCIAL SM. VOL. (16)	COMMERCIAL LG. VOL. (17)	COMMERCIAL TRANS-PORTATION (18)
1	STATE & FED TAXES & OTHER EXPENSE						
2							
3	**TAXES OTHER THAN INCOME**						
4	PROPERTY TAXES - TRANSMISSION	TRANPLT	$112,856	$5,878	$44,360	$1,978	$3,835
5	PROPERTY TAXES - DISTRIBUTION	DISTRPLT	2,113,330	115,309	483,184	20,674	35,551
6	PROPERTY TAXES - GENERAL	GENPLT	145,912	8,144	21,265	606	1,007
7	PAYROLL TAXES	LABOR	431,153	24,063	62,836	1,789	2,976
8	OTHER TAXES	PLANT	113,380	6,186	25,970	1,095	1,900
9	TOTAL TAX OTHER THAN INCOME		2,916,631	159,579	637,615	26,142	45,269
10							
11	TOTAL OPERATING EXPENSE BEFORE INCOME TAX		$27,597,058	$1,502,677	$4,830,272	$153,553	$278,418
12	**FEDERAL & STATE TAX CALCULATION**						
13							
14	OPERATING REVENUES		$36,447,887	$1,458,710	$9,708,828	$250,303	$538,704
15	OPERATING EXPENSES						
16	OPERATION & MAINTENANCE EXP		18,951,733	1,028,046	3,047,425	84,990	158,421
17	DEPRECIATION		5,728,693	315,051	1,145,232	42,422	74,727
18	TAXES OTHER THAN INCOME		2,916,631	159,579	637,615	26,142	45,269
19	OPERATING INCOME BEFORE INCOME TAXES		8,850,830	(43,967)	4,878,556	96,750	260,287
20							
21	INTEREST EXPENSE		(3,784,517)	(205,923)	(903,516)	(37,060)	(66,338)
22							
23	BOOK TAXABLE INCOME		5,066,312	(249,890)	3,975,040	59,690	193,948
24							
25	STATE TAX @ 0.00%		0	0	0	0	0
26							
27	STATE AND FEDERAL TAXABLE BASIS		5,066,312	(249,890)	3,975,040	59,688	193,948
28							
29	STATE AND FEDERAL INCOME TAX @ 38.41%		1,945,972	(95,983)	1,526,814	22,926	74,496
30	AMORTIZATION OF ITC	PLANT	0	0	0	0	0
31	BLANK.	PLANT	0	0	0	0	0
32	TOTAL STATE AND FEDERAL TAXES		1,945,972	(95,983)	1,526,814	22,926	74,496
33							
34	TOTAL STATE & FEDERAL INCOME TAX		1,945,972	(95,983)	1,526,814	22,926	74,496
35							
36	NET INCOME AFTER TAX		$6,904,858	$52,015	$3,351,742	$73,824	$185,791
37							

UNS GAS COMPANY
COST OF SERVICE STUDY
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		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	STATE & FED TAXES & OTHER EXPENSE				
2					
3	**TAXES OTHER THAN INCOME**				
4	PROPERTY TAXES - TRANSMISSION	TRANPLT	$879	$1,605	$26,419
5	PROPERTY TAXES - DISTRIBUTION	DISTRPLT	12,023	15,043	229,202
6	PROPERTY TAXES - GENERAL	GENPLT	224	426	6,331
7	PAYROLL TAXES	LABOR	663	1,260	18,707
8	OTHER TAXES	PLANT	616	803	12,316
9	TOTAL TAX OTHER THAN INCOME		14,406	19,137	292,975
10					
11	TOTAL OPERATING EXPENSE BEFORE INCOME TAX		$69,185	$107,475	$1,700,047
12	**FEDERAL & STATE TAX CALCULATION**				
13					
14	OPERATING REVENUES		$135,827	$124,155	$1,669,093
15	OPERATING EXPENSES				
16	OPERATION & MAINTENANCE EXP		33,475	56,760	917,590
17	DEPRECIATION		21,305	31,577	489,481
18	TAXES OTHER THAN INCOME		14,406	19,137	292,975
19	OPERATING INCOME BEFORE INCOME TAXES		66,642	16,681	(30,954)
20					
21	INTEREST EXPENSE		(19,399)	(27,973)	(437,044)
22					
23	BOOK TAXABLE INCOME		47,242	(11,293)	(467,998)
24					
25	STATE TAX @ 0.00%		0	0	0
26					
27	STATE AND FEDERAL TAXABLE BASIS		47,242	(11,293)	(467,998)
28					
29	STATE AND FEDERAL INCOME TAX @ 38.41%		18,146	(4,338)	(179,758)
30	AMORTIZATION OF ITC	PLANT	0	0	0
31	BLANK.	PLANT	0	0	0
32	TOTAL STATE AND FEDERAL TAXES		18,146	(4,338)	(179,758)
33					
34	TOTAL STATE & FEDERAL INCOME TAX		18,146	(4,338)	(179,758)
35					
36	NET INCOME AFTER TAX		$48,496	$21,018	$148,804
37					

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	STATE & FED TAXES & OTHER EXPENSE						
2							
3	**TAXES OTHER THAN INCOME**						
4	PROPERTY TAXES - TRANSMISSION	TRANPLT	$9,523	$1,882	$7,797	$185	$97
5	PROPERTY TAXES - DISTRIBUTION	DISTRPLT	90,708	17,185	68,564	1,582	872
6	PROPERTY TAXES - GENERAL	GENPLT	3,207	445	1,921	43	27
7	PAYROLL TAXES	LABOR	9,475	1,314	5,678	128	81
8	OTHER TAXES	PLANT	4,878	917	3,681	85	47
9	TOTAL TAX OTHER THAN INCOME		117,790	21,744	87,641	2,024	1,124
10							
11	TOTAL OPERATING EXPENSE BEFORE INCOME TAX		$778,465	$117,830	$519,711	$17,598	$26,545
12	**FEDERAL & STATE TAX CALCULATION**						
13							
14	OPERATING REVENUES		$1,646,961	$151,836	$666,877	$67,573	$35,753
15	OPERATING EXPENSES						
16	OPERATION & MAINTENANCE EXP		456,349	60,353	285,920	12,181	23,504
17	DEPRECIATION		204,325	35,733	146,149	3,393	1,917
18	TAXES OTHER THAN INCOME		117,790	21,744	87,641	2,024	1,124
19	OPERATING INCOME BEFORE INCOME TAXES		868,497	34,006	147,167	49,975	9,208
20							
21	INTEREST EXPENSE		(171,887)	(32,091)	(130,375)	(3,163)	(2,277)
22							
23	BOOK TAXABLE INCOME		696,610	1,916	16,792	46,812	6,931
24							
25	STATE TAX @ 0.00%		0	0	0	0	0
26							
27	STATE AND FEDERAL TAXABLE BASIS		696,610	1,916	16,792	46,812	6,931
28							
29	STATE AND FEDERAL INCOME TAX @ 38.41%		267,568	736	6,450	17,980	2,662
30	AMORTIZATION OF ITC	PLANT	0	0	0	0	0
31	BLANK.	PLANT	0	0	0	0	0
32	TOTAL STATE AND FEDERAL TAXES		267,568	736	6,450	17,980	2,662
33							
34	TOTAL STATE & FEDERAL INCOME TAX		267,568	736	6,450	17,980	2,662
35							
36	NET INCOME AFTER TAX		$600,929	$33,271	$140,717	$31,994	$6,546
37							

UNS GAS COMPANY
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			TOTAL COMPANY	CAPACITY	COMMODITY	CUSTOMER
1	DEVELOPMENT OF RATE BASE					
2						
3	**GAS PLANT IN SERVICE**					
4						
5	INTANGIBLE PLANT					
6	302-FRANCHISES & CONSENTS	LABOR	$362,992	$97,335	$0	$265,657
7	302-FRANCHISES & CONSENTS - ACQ ADJ	LABOR	(36,464)	(9,778)	(0)	(26,687)
8	303-MISC. INTANGIBLE PLANT	LABOR	777,500	208,483	0	569,016
9	303-MISC. INTANGIBLE PLANT - ACQ ADJ	LABOR	(36,142)	(9,691)	(0)	(26,451)
10	TOTAL INTANGIBLE PLANT		1,067,886	286,349	0	781,537
11						
12	TRANSMISSION PLANT					
13	365-LAND & LAND RIGHTS	TRANS	86,073	86,073	0	0
14	365-LAND & LAND RIGHTS - ACQ ADJ	TRANS	(15,425)	(15,425)	0	0
15	366-STRUCTURES & IMPROVEMENTS	TRANS	15,792	15,792	0	0
16	366-STRUCTURES & IMPROVE - ACQ ADJ	TRANS	(2,352)	(2,352)	0	0
17	367-MAINS	TRANS	17,486,880	17,486,880	0	0
18	367-MAINS - ACQ ADJ	TRANS	(1,604,647)	(1,604,647)	0	0
19	369-MEASURING & REG STATION EQUIP.	TRANS	792,065	792,065	0	0
20	369-MEAS & REG STA EQUIP - ACQ ADJ	TRANS	(424,444)	(424,444)	0	0
21	371-OTHER EQUIPMENT	TRANS	0	0	0	0
22	371-OTHER EQUIPMENT - ACQ ADJ	TRANS	(24,187)	(24,187)	0	0
23	TOTAL TRANSMISSION PLANT		16,309,754	16,309,754	0	0
24						
25	DISTRIBUTION PLANT					
26	374-LAND & LAND RIGHTS	DISTR	241,754	241,754	0	0
27	374-LAND & LAND RIGHTS - ACQ ADJ	DISTR	(38,784)	(38,784)	0	0
28	375-STRUCTURES & IMPROV	DISTR	10,258	10,258	0	0
29	375-STRUCTURES & IMPROV - ACQ ADJ	DISTR	(247)	(247)	0	0
30	376-MAINS	DISTMAIN	157,127,396	157,127,396	0	0
31	376-MAINS - ACQ ADJ	DISTMAIN	(17,621,607)	(17,621,607)	0	0
32	378-MEAS. & REG. EQUIP-GEN	DISTREG	2,344,082	2,344,082	0	0
33	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	DISTREG	(188,503)	(188,503)	0	0
34	379-MEAS. & REG. EQUIP-CITY GATE	DISTREG	2,437,071	2,437,071	0	0
35	379-MEAS & REG EQ-CITY GATE - ACQ ADJ	DISTREG	(239,569)	(239,569)	0	0
36	380-SERVICES	CUST380	86,448,392	0	0	86,448,392
37	380-SERVICES - ACQ ADJ	CUST380	(6,640,413)	0	0	(6,640,413)
38	381-METERS	CUST381	13,780,226	0	0	13,780,226
39	381-METERS - ACQ ADJ	CUST381	(1,160,990)	0	0	(1,160,990)
40	382-METER INSTALLATIONS	CUST382	8,633,492	0	0	8,633,492
41	382-METER INSTALLATIONS - ACQ ADJ	CUST382	(744,797)	0	0	(744,797)
42						
43						
44						
45						

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			TOTAL COMPANY	CAPACITY	COMMODITY	CUSTOMER
1	DEVELOPMENT OF RATE BASE					
2						
3	**GAS PLANT IN SERVICE CONTINUED**					
4						
5	DISTRIBUTION PLANT CONTINUED					
6	383-REGULATORS	CUST383	2,886,748	0	0	2,886,748
7	383-REGULATORS - ACQ ADJ	CUST383	(178,700)	0	0	(178,700)
8	384-REGULATOR INSTALLATIONS	CUST384	1,352,659	0	0	1,352,659
9	384-REGULATOR INSTALLATIONS - ACQ ADJ	CUST384	(82,263)	0	0	(82,263)
10	385-INDUSTRIAL MEAS. EQUIP	CUST385	1,433,311	0	0	1,433,311
11	385-INDUSTRIAL MEAS. EQUIP - ACQ ADJ	CUST385	(106,448)	0	0	(106,448)
12	387-OTHER EQUIPMENT	DISTMAIN	1,069,684	1,069,684	0	0
13	387-OTHER EQUIPMENT - ACQ ADJ	DISTMAIN	(146,048)	(146,048)	0	0
14	TOTAL DISTRIBUTION PLANT		250,616,704	144,995,488	0	105,621,216
15						
16	GENERAL PLANT					
17	389-LAND & LAND RIGHTS	LABOR	394,121	105,682	0	288,439
18	389-LAND & LAND RIGHTS - ACQ ADJ	LABOR	(49,201)	(13,193)	(0)	(36,008)
19	390-STRUCTURES & IMPROVE	LABOR	5,345,351	1,433,334	1	3,912,017
20	390-STRUCTURES & IMPROVE - ACQ ADJ	LABOR	(123,017)	(32,987)	(0)	(90,031)
21	391-OFFICE FURN & EQUIPMENT	LABOR	2,102,879	563,878	0	1,539,001
22	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	LABOR	(643,851)	(172,646)	(0)	(471,205)
23	392-TRANSPORTATION EQUIP	LABOR	7,181,119	1,925,587	1	5,255,532
24	392-TRANSPORTATION EQUIP - ACQ ADJ	LABOR	(85,465)	(22,917)	(0)	(62,548)
25	393-STORES EQUIPMENT	LABOR	200,996	53,896	0	147,100
26	393-STORES EQUIPMENT - ACQ ADJ	LABOR	(17,775)	(4,766)	(0)	(13,008)
27	394-TOOLS, SHOP & GARAGE EQUIP	LABOR	2,271,486	609,090	0	1,662,396
28	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	LABOR	(230,699)	(61,861)	(0)	(168,838)
29	395-LABORATORY EQUIPMENT	LABOR	786,828	210,985	0	575,843
30	395-LABORATORY EQUIPMENT - ACQ ADJ	LABOR	(78,875)	(21,150)	(0)	(57,725)
31	396-POWER OPERATED EQUIP	LABOR	1,279,076	342,979	0	936,097
32	396-POWER OPERATED EQUIP - ACQ ADJ	LABOR	(5,511)	(1,478)	(0)	(4,033)
33	397-COMMUNICATION EQUIP	LABOR	1,101,825	295,450	0	806,376
34	397-COMMUNICATION EQUIP - ACQ ADJ	LABOR	(153,703)	(41,215)	(0)	(112,488)
35	398-MISCELLANEOUS EQUIP	LABOR	277,567	74,428	0	203,139
36	398-MISCELLANEOUS EQUIP - ACQ ADJ	LABOR	(29,611)	(7,940)	(0)	(21,671)
37	399-OTHER TANGIBLE PROPERTY	LABOR	0	0	0	0
38	TOTAL GENERAL PLANT		19,523,542	5,235,157	2	14,288,386
39						
40	COMMON PLANT	LABOR	0	0	0	0
41						
42	TOTAL GAS PLANT IN SERVICE		287,517,886	166,826,748	2	120,691,139
43						
44	TOTAL GAS PLANT IN SERVICE ACQ ADJ		(30,709,737)	(20,705,435)	(0)	(10,004,303)
45						

UNS GAS COMPANY
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			TOTAL COMPANY	CAPACITY	COMMODITY	CUSTOMER
1	DEVELOPMENT OF RATE BASE CONT.					
2						
3	**DEPRECIATION RESERVE CONTINUED**					
4						
5	**DEPRECIATION RESERVE**					
6	INTANGIBLE RESERVE					
7	302-FRANCHISES & CONSENTS	PLT302	185,148	49,647	0	135,501
8	302-FRANCHISES & CONSENTS - ACQ ADJ	PLT302	(7,030)	(1,885)	(0)	(5,145)
9	303-MISC. INTANGIBLE PLANT	PLT303	289,837	77,719	0	212,118
10	303-MISC. INTANGIBLE PLANT - ACQ ADJ	PLT303	(7,363)	(1,974)	(0)	(5,389)
11	TOTAL INTANGIBLE PLANT		460,590	123,505	0	337,085
12						
13	TRANSMISSION RESERVE					
14	365-LAND & LAND RIGHTS	PLT365	15,259	15,259	0	0
15	365-LAND & LAND RIGHTS - ACQ ADJ	PLT365	(125)	(125)	0	0
16	366-STRUCTURES & IMPROVEMENTS	PLT366	4,130	4,130	0	0
17	366-STRUCTURES & IMPROV - ADQ ADJ	PLT366	(759)	(759)	0	0
18	367-MAINS	PLT367	3,670,676	3,670,676	0	0
19	367-MAINS - ACQ ADJ	PLT367	(124,060)	(124,060)	0	0
20	369-MEASURING & REG STATION EQUIP.	PLT369	318,418	318,418	0	0
21	369-MEASURING & REG STA EQ - ACQ ADJ	PLT369	(33,265)	(33,265)	0	0
22	371-OTHER EQUIPMENT	PLT371	0	0	0	0
23	371-OTHER EQUIPMENT - ACQ ADJ	PLT371	(5,565)	(5,565)	0	0
24	TOTAL TRANSMISSION PLANT		3,844,709	3,844,709	0	0
25						
26	DISTRIBUTION RESERVE					
27	374.1-LAND	PLT374	31,809	31,809	0	0
28	374.1-LAND - ACQ ADJ	PLT374	(182)	(182)	0	0
29	375-STRUCTURES & IMPROV	PLT375	7,027	7,027	0	0
30	375-STRUCTURES & IMPROV - ACQ ADJ	PLT375	(39)	(39)	0	0
31	376-MAINS	PLT376	37,521,357	37,521,357	0	0
32	376-MAINS - ACQ ADJ	PLT376	(1,835,978)	(1,835,978)	0	0
33	378-MEAS. & REG. EQUIP-GEN	PLT378	657,026	657,026	0	0
34	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	PLT378	(28,040)	(28,040)	0	0
35	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	485,438	485,438	0	0
36	379-MEAS & REG EQ-CITY GATE - ACQ ADJ	PLT379	(28,168)	(28,168)	0	0
37	380-SERVICES	PLT380	26,830,743	0	0	26,830,743
38	380-SERVICES - ACQ ADJ	PLT380	(937,682)	0	0	(937,682)
39	381-METERS	PLT381	6,164,614	0	0	6,164,614
40	381-METERS - ACQ ADJ	PLT381	(116,507)	0	0	(116,507)
41	382-METER INSTALLATIONS	PLT382	1,826,540	0	0	1,826,540
42	382-METER INSTALLATIONS - ACQ ADJ	PLT382	(88,125)	0	0	(88,125)
43						
44						
45						

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			TOTAL COMPANY	CAPACITY	COMMODITY	CUSTOMER
1	DEVELOPMENT OF RATE BASE CONT.					
2						
3	**DEPRECIATION RESERVE CONTINUED**					
4	DISTRIBUTION RESERVE CONTINUED					
5	383-REGULATORS	PLT383	1,048,907	0	0	1,048,907
6	383-REGULATORS - ACQ ADJ	PLT383	(22,959)	0	0	(22,959)
7	384-REGULATOR INSTALLATIONS	PLT384	190,999	0	0	190,999
8	384-REGULATOR INSTALLATIONS - ACQ ADJ	PLT384	(11,380)	0	0	(11,380)
9	385-INDUSTRIAL MEAS. EQUIP	PLT385	665,131	0	0	665,131
10	385-INDUSTRIAL MEAS. EQUIP - ACQ ADJ	PLT385	(13,537)	0	0	(13,537)
11	387-OTHER EQUIPMENT	PLT387	503,177	503,177	0	0
12	387-OTHER EQUIPMENT - ACQ ADJ	PLT387	(22,146)	(22,146)	0	0
13	TOTAL DISTRIBUTION RESERVE		72,828,026	37,291,281	0	35,536,745
14						
15	GENERAL PLANT RESERVE					
16	389-LAND AND LAND RIGHTS	PLT389	13,475	3,613	0	9,862
17	389-LAND AND LAND RIGHTS - ACQ ADJ	PLT389	(1,253)	(336)	(0)	(917)
18	390-STRUCTURES & IMPROVE	PLT390	284,256	76,222	0	208,034
19	390-STRUCTURES & IMPROVE - ACQ ADJ	PLT390	(23,370)	(6,267)	(0)	(17,103)
20	391-OFFICE FURN & EQUIPMENT	PLT391	1,461,457	391,883	0	1,069,573
21	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	PLT391	(392,983)	(105,377)	(0)	(287,607)
22	392-TRANSPORTATION EQUIP	PLT392	3,410,962	914,635	0	2,496,327
23	392-TRANSPORTATION EQUIP - ACQ ADJ	PLT392	(101,555)	(27,232)	(0)	(74,324)
24	393-STORES EQUIPMENT	PLT393	35,647	9,559	0	26,088
25	393-STORES EQUIPMENT - ACQ ADJ	PLT393	(2,606)	(699)	(0)	(1,907)
26	394-TOOLS, SHOP & GARAGE EQUIPMENT	PLT394	720,244	193,131	0	527,114
27	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	PLT394	(40,385)	(10,829)	(0)	(29,556)
28	395-LABORATORY EQUIPMENT	PLT395	330,922	88,735	0	242,186
29	395-LABORATORY EQUIPMENT - ACQ ADJ	PLT395	(36,929)	(9,902)	(0)	(27,026)
30	396-POWER OPERATED EQUIPMENT	PLT396	231,788	62,153	0	169,635
31	396-POWER OPERATED EQUIP - ACQ ADJ	PLT396	(1,490)	(399)	(0)	(1,090)
32	397-COMMUNICATION EQUIP	PLT397	542,215	145,393	0	396,822
33	397-COMMUNICATION EQUIP - ACQ ADJ	PLT397	(46,354)	(12,430)	(0)	(33,925)
34	398-MISCELLANEOUS EQUIP	PLT398	96,341	25,834	0	70,508
35	398-MISCELLANEOUS EQUIP - ACQ ADJ	PLT398	(5,811)	(1,558)	(0)	(4,252)
36	399-OTHER TANGIBLE PROPERTY	PLT399	0	0	0	0
37	TOTAL GENERAL PLANT RESERVE		6,474,571	1,736,129	1	4,738,442
38						
39	COMMON PLANT	PLTCOMN	0	0	0	0
40						
41	TOTAL DEPRECIATION RESERVE		83,607,897	42,995,625	1	40,612,272
42						
43	TOTAL DEPRECIATION RESERVE ACQ ADJ		(3,935,647)	(2,257,215)	(0)	(1,678,431)
44						
45	NET PLANT IN SERVICE		$203,909,989	$123,831,122	$1	$80,078,867
46						

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			TOTAL COMPANY	CAPACITY	COMMODITY	CUSTOMER
1	DEVELOPMENT OF RATE BASE CONT.					
2						
3	**OTHER RATE BASE ITEMS**					
4						
5	WORKING CAPITAL					
6	CASH WORKING CAPITAL					
7	PLANT	PLANT	$1,568	$910	$0	$658
8	COMMODITY	WCGC	0	0	0	0
9	OPERATIONS & MAINTENANCE	WCOTH	0	0	0	0
10	OTHER	WCOTH	0	0	0	0
11	TOTAL CASH WORKING CAPITAL		1,568	910	0	658
12	MATERIALS & SUPPLIES	PLANT	2,010,788	1,166,721	0	844,067
13	PREPAYMENTS	PLANT	352,564	204,569	0	147,996
14	TOTAL WORKING CAPITAL		2,364,921	1,372,200	0	992,721
15						
16	LESS: CUSTOMER CONTRIBUTIONS					
17	CUST ADVANCES FOR CONSTRUCTION	PLANT	(11,235,876)	(6,519,402)	(0)	(4,716,474)
18	CUSTOMER DEPOSITS	PLANT	(2,609,271)	(1,513,980)	(0)	(1,095,291)
19						
20	OTHER RATE BASE					
21	CWIP	DISTRPLT	0	0	0	0
22	Y2K COSTS & GIC DEF	PAYXAG	0	0	0	0
23	C.A.R.E.S.	THERMS	492,590	0	492,590	0
24	OTHER - WARM SPIRIT	RESNTPT	(22,372)	(10,806)	(0)	(11,566)
25	TOTAL OTHER		470,218	(10,806)	492,590	(11,566)
26						
27	LESS					
28	ACCUMULATED DEFERRED INC. TAXES	PLANT	(10,606,875)	(6,154,436)	(0)	(4,452,439)
29						
30						
31	TOTAL RATE BASE		$182,293,105	$111,004,698	$492,591	$70,795,817
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			TOTAL COMPANY	CAPACITY	COMMODITY	CUSTOMER
1	OPERATING REVENUES					
2						
3	**REVENUES**					
4						
5	GAS OPERATING REVENUES					
6						
7	SALES REVENUES					
8	FIRM SALES OF GAS		$51,157,764	23,141,675	51,626	27,967,274
9	INTERR SALES GAS COST REV	GASSALES	0	0	0	0
10	INTERR SALES PROFIT MARGINS	DEMGAS	0	0	0	0
11	INTERRUPTIBLE TRANSPORTATION	DISTR	0	0	0	0
12	SALES FOR RESALE	DEMGAS	0	0	0	0
13	TOTAL SALES OF GAS		51,157,764	23,141,675	51,626	27,967,274
14						
15	OTHER OPERATING REVENUES					
16	FORFEITED DISCOUNTS	PLANT	495,690	287,615	0	208,075
17	MISCELLANEOUS SERVICE REV	CUST487B	1,211,079	0	0	1,211,079
18	OTHER REVENUE	DEMGAS	37,974	37,974	0	0
19	OTHER REVENUE	PLANT	0	0	0	0
20	OTHER REVENUE	PLANT	0	0	0	0
21	TOTAL OTHER OPERATING REV		1,744,743	325,589	0	1,419,154
22						
23	TOTAL GAS OPERATING REVENUE		$52,902,507	$23,467,263	$51,626	$29,386,428
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			TOTAL COMPANY	CAPACITY	COMMODITY	CUSTOMER
1	OPERATION & MAINTENANCE EXPENSE					
2						
3	**OPERATION & MAINTENANCE EXPENSE**					
4	PRODUCTION EXPENSE					
5	421-PURCHASED POWER	DEMGAS	0	0	0	0
6	805-PURCHASED GAS EXPENSES	DEMGAS	0	0	0	0
7	807-PURCHASED GAS COST EXPENSES					
8	NON-RECONCILABLE	DEMGAS	397,635	397,635	0	0
9	CAPACITY RELATED	DEMGAS	0	0	0	0
10	COMMODITY RELATED	GASSALES	0	0	0	0
11	TOTAL ACCOUNT 807		397,635	397,635	0	0
12	TOTAL PURCHASED GAS SUPPLY		397,635	397,635	0	0
13						
14	TRANSMISSION EXPENSE					
15	856-MAINS EXPENSE	TRANS	14,172	14,172	0	0
16	857-MEASURING & REG. STATION	TRANS	0	0	0	0
17	864-MAINTENANCE OF COMPRESSOR STATION EC	TRANS	0	0	0	0
18	870-OPERATION SUPERVISION AND ENGINEERING	TRANS	349,645	349,645	0	0
19	TOTAL TRANSMISSION		363,817	363,817	0	0
20						
21	DISTRIBUTION EXPENSE					
22	431-INTEREST ON CUSTOMER DEPOSITS	LABDO	137,200	42,667	0	94,533
23	871-LOAD DISPATCHING	DISTR	0	0	0	0
24	874-MAINS & SERVICING EXPENSE	PLT376380	1,540,668	980,021	0	560,647
25	875-MEAS./REG. STATION EXPENSE	PLT378	229,538	229,538	0	0
26	876-MEAS./REG. STATION EXPENSE	PLT379	188,393	188,393	0	0
27	877-MEAS./REG. STATION EXPENSE	PLT383	28,503	0	0	28,503
28	878-METER EXPENSE	PLT381	1,485,403	0	0	1,485,403
29	879-CUSTOMER INSTALL EXP	PLT38284	798,365	0	0	798,365
30	880-OTHER EXPENSES	EXP87479	1,991,424	651,838	0	1,339,586
31	881-RENTS	DISTR	12,217	12,217	0	0
32	885-MAINT. SUPERV. & ENG.	LABDM	241,622	125,497	0	116,125
33	886-MAINT. OF STRUCTURES	PLT375	973,099	973,099	0	0
34	887-MAINT. OF MAINS	PLT376	143	143	0	0
35	889-MAINT. MEAS./REG	PLT378	32,400	32,400	0	0
36	890-MAINT. MEAS./REG	PLT379	10,950	10,950	0	0
37	891-MAINT. MEAS./REG	PLT383	2,845	0	0	2,845
38	892-MAINT. OF SERVICES	PLT380	586,448	0	0	586,448
39	893-MAINT. OF METER	PLT381	333,085	0	0	333,085
40	894-MAINT. OF OTHER EQUIP.	PLT387	53,271	53,271	0	0
41	TOTAL DISTRIBUTION EXP		8,645,572	3,300,033	0	5,345,539
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			TOTAL COMPANY	CAPACITY	COMMODITY	CUSTOMER
1	OPERATION & MAINT EXP CONT.					
2						
3	**OPERATION & MAINTENANCE EXPENSE CONTINUED**					
4	CUSTOMER ACCOUNT					
5	901-SUPERVISION	LABCA	50,009	4	0	50,005
6	902-METER READING EXPENSE	CUST902	983,242	0	0	983,242
7	903-CUST RECORDS & COLLECT	CUST903	4,002,584	0	0	4,002,584
8	904-UNCOLLECTIBLE ACCOUNTS	BADDEBT	688,379	400,850	2,240	287,952
9	905-MISC CUST ACCTS EXP	EXP9024	20,265	1,432	8	18,835
10	906-CUSTOMER SERVICE & INFO	CUST10	0	0	0	0
11	907-SUPERV. CUSTOMER SERV.	LABCS	0	0	0	0
12	908-CUSTOMER ASSISTANCE	CUST10	69,987	0	0	69,987
13	909-INFO & INSTRUCTIONAL ADVERT.	CUST10	104,336	0	0	104,336
14	910-MISC. CUST. SERV. & INFO.	EXP9089	700	0	0	700
15	CARES DISCOUNTS	THERMS	0	0	0	0
16	CARES EXPENSES	THERMS	0	0	0	0
17	TOTAL CUSTOMER ACCTS EXP		5,919,503	402,285	2,248	5,517,642
18						
19	SALES EXPENSE					
20	912-DEMONSTRATING & SELLING	CDA912	0	0	0	0
21	913-ADVERTISING EXPENSES	CDA913	170	0	0	170
22	TOTAL SALES EXPENSE		170	0	0	170
23						
24	ADMINISTRATIVE & GENERAL EXPENSE					
25	920-ADMIN & GENERAL SALARY	PAYXAG	3,335,674	894,447	0	2,441,227
26	921-OFFICE SUPPLIES & EXP	PAYXAG	1,408,798	377,763	0	1,031,035
27	923-OUTSIDE SERV EMPLOYED	PAYXAG	(543,925)	(145,851)	(0)	(398,074)
28	924-PROPERTY INSURANCE	PAYXAG	934,046	250,461	0	683,585
29	925-INJURIES & DAMAGES	PAYXAG	11,505	3,085	0	8,420
30	926-EMPLOYED PENSION & BENF	PAYXAG	576,216	154,510	0	421,706
31	928-REGULATORY COMM EXPENSE	TOTREV	2,622,675	1,163,404	2,559	1,456,851
32	930-MISCELLANEOUS GEN EXP	PAYXAG	992,161	266,044	0	726,117
33	931-RENTS	PAYXAG	102,113	27,381	0	74,732
34	932-MAINT OF GENERAL PLT	GENPLT	350,787	94,062	0	256,725
35	TOTAL ADMIN & GEN EXPENSE		9,790,050	3,085,306	2,560	6,702,324
36						
37	TOTAL GAS O & M EXPENSE		$25,116,748	$7,549,077	$4,808	$17,565,675
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			TOTAL COMPANY	CAPACITY	COMMODITY	CUSTOMER
1	DEPRECIATION & AMORT EXPENSE					
2						
3	**DEPRECIATION AND AMORITIZATION EXPENSE**					
4						
5	407-AMOR Y2K EXP; GPS & PRESC GAIN	PAYXAG	46,518	12,474	0	34,044
6	407-AMORTIZATION OF C.A.R.E.S.	PLANT	164,197	95,272	0	68,925
7						
8	INTANGIBLE PLT DEPRECIATION EXPENSE					
9	302-FRANCHISES & CONSENTS	PLT302	15,524	4,163	0	11,361
10	302-FRANCHISES & CONSENTS - ACQ ADJ	PLT302	(1,493)	(400)	(0)	(1,093)
11	303-MISC. INTANGIBLE PLANT	PLT303	1,214,673	325,710	0	888,963
12	303-MISC. INTANGIBLE PLANT - ACQ ADJ	PLT303	(2,049)	(549)	(0)	(1,499)
13	TOTAL INTANGIBLE PLT DEPR EXP		1,226,655	328,922	0	897,733
14						
15	TRANSMISSION PLT DEPR EXP					
16	365-LAND & LAND RIGHTS	PLT365	754	754	0	0
17	365-LAND & LAND RIGHTS - ACQ ADJ	PLT365	(129)	(129)	0	0
18	366-STRUCTURES & IMPROVEMENTS	PLT366	605	605	0	0
19	366-STRUCTURES & IMPROVE - ACQ ADJ	PLT366	(95)	(95)	0	0
20	367-MAINS	PLT367	313,477	313,477	0	0
21	367-MAINS - ACQ ADJ	PLT367	(25,713)	(25,713)	0	0
22	369-MEASURING & REG STATION EQ.	PLT369	51,161	51,161	0	0
23	369-MEASURING & REG STA EQ - ACQ ADJ	PLT369	(6,869)	(6,869)	0	0
24	371-OTHER EQUIPMENT	PLT371	0	0	0	0
25	371-OTHER EQUIPMENT - ACQ ADJ	PLT371	(883)	(883)	0	0
26	TOTAL TRANS PLT DEPR EXP		332,308	332,308	0	0
27						
28	DISTRIBUTION PLT DEPR EXP					
29	375-STRUCTURES & IMPROV	PLT375	1,294	1,294	0	0
30	375-STRUCTURES & IMPROV - ACQ ADJ	PLT375	(195)	(195)	0	0
31	376-MAINS	PLT376	3,218,602	3,218,602	0	0
32	376-MAINS - ACQ ADJ	PLT376	(380,982)	(380,982)	0	0
33	378-MEAS. & REG. EQUIP-GEN	PLT378	66,014	66,014	0	0
34	378-MEAS. & REG. EQUIP-GEN - ACQ ADJ	PLT378	(5,833)	(5,833)	0	0
35	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	63,591	63,591	0	0
36	379-MEAS. & REG. EQ-CITY GATE - ACQ ADJ	PLT379	(5,862)	(5,862)	0	0
37	380-SERVICES	PLT380	2,228,476	0	0	2,228,476
38	380-SERVICES - ACQ ADJ	PLT380	(195,164)	0	0	(195,164)
39	381-METERS	PLT381	250,749	0	0	250,749
40	381-METERS - ACQ ADJ	PLT381	(24,340)	0	0	(24,340)
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			TOTAL COMPANY	CAPACITY	COMMODITY	CUSTOMER
1	DEPREC & AMORT EXP CONT.					
2	DISTRIBUTION PLT DEPR EXP CONTINUED					
3	382-METER INSTALLATIONS	PLT382	185,804	0	0	185,804
4	382-METER INSTALLATIONS - ACQ ADJ	PLT382	(18,340)	0	0	(18,340)
5	383-REGULATORS	PLT383	67,574	0	0	67,574
6	383-REGULATORS - ACQ ADJ	PLT383	(4,774)	0	0	(4,774)
7	384-REGULATOR INSTALLATIONS	PLT384	34,830	0	0	34,830
8	384-REGULATOR INSTALLATIONS - ACQ ADJ	PLT384	(2,387)	0	0	(2,387)
9	385-INDUSTRIAL MEAS. EQUIP.	PLT385	20,338	0	0	20,338
10	385-INDUSTRIAL MEAS. EQUIP. - ACQ ADJ	PLT385	(2,924)	0	0	(2,924)
11	387-OTHER EQUIPMENT	PLT387	(12,250)	(12,250)	0	0
12	387-OTHER EQUIPMENT - ACQ ADJ	PLT387	(4,617)	(4,617)	0	0
13	TOTAL DISTRIBUTION PLT DEPR EXP		5,479,601	2,939,760	0	2,539,840
14						
15	GENERAL PLANT DEPR EXP					
16	390-STRUCTURES & IMPROVE	PLT390	211,692	56,764	0	154,928
17	390-STRUCTURES & IMPROVE - ACQ ADJ	PLT390	(6,895)	(1,849)	(0)	(5,046)
18	391-OFFICE FURN & EQUIPMENT	PLT391	613,706	164,563	0	449,143
19	391-OFFICE FURN & EQUIPMENT - ACQ ADJ	PLT391	(97,872)	(26,244)	(0)	(71,628)
20	392-TRANSPORTATION EQUIP	PLT392	(17,941)	(4,811)	(0)	(13,131)
21	392-TRANSPORTATION EQUIP - ACQ ADJ	PLT392	0	0	0	0
22	393-STORES EQUIPMENT	PLT393	4,974	1,334	0	3,640
23	393-STORES EQUIPMENT - ACQ ADJ	PLT393	(537)	(144)	(0)	(393)
24	394-TOOLS, SHOP & GARAGE EQ	PLT394	78,999	21,183	0	57,816
25	394-TOOLS, SHOP & GARAGE EQ - ACQ ADJ	PLT394	(9,163)	(2,457)	(0)	(6,706)
26	395-LABORATORY EQUIPMENT	PLT395	68,667	18,413	0	50,254
27	395-LABORATORY EQUIPMENT - ACQ ADJ	PLT395	(8,445)	(2,264)	(0)	(6,180)
28	396-POWER OPERATED EQUIPMENT	PLT396	91,483	24,531	0	66,952
29	396-POWER OPERATED EQUIP - ACQ ADJ	PLT396	(453)	(121)	(0)	(332)
30	397-COMMUNICATION EQUIP	PLT397	63,664	17,071	0	46,593
31	397-COMMUNICATION EQUIP - ACQ ADJ	PLT397	(10,194)	(2,733)	(0)	(7,460)
32	398-MISCELLANEOUS EQUIP	PLT398	10,264	2,752	0	7,512
33	398-MISCELLANEOUS EQUIP - ACQ ADJ	PLT398	(1,223)	(328)	(0)	(895)
34	399-OTHER TANGIBLE PROPERTY	PLT399	0	0	0	0
35	TOTAL GENERAL PLT DEPR EXP		990,727	265,659	0	725,068
36						
37	TOTAL DEPRECIATION & AMORTIZATION EXPENSE		$8,240,005	$3,974,395	$0	$4,265,610
38						
39	TOTAL ACQUISITION ADJUSTMENT DEPR EXPENSE		(817,431)	(468,269)	(0)	(349,162)
40						
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			TOTAL COMPANY	CAPACITY	COMMODITY	CUSTOMER
1	STATE & FED TAXES & OTHER EXPENSE					
2						
3	**TAXES OTHER THAN INCOME**					
4	PROPERTY TAXES - TRANSMISSION	TRANPLT	$217,294	$217,294	$0	$0
5	PROPERTY TAXES - DISTRIBUTION	DISTRPLT	3,203,226	1,853,242	0	1,349,984
6	PROPERTY TAXES - GENERAL	GENPLT	189,559	50,829	0	138,730
7	PAYROLL TAXES	LABOR	560,124	150,195	0	409,929
8	OTHER TAXES	PLANT	171,875	99,727	0	72,148
9	TOTAL TAX OTHER THAN INCOME		4,342,079	2,371,287	0	1,970,791
10						
11	TOTAL OPERATING EXPENSE BEFORE INCOME TAX		$37,698,831	$13,894,760	$4,809	$23,802,076
12	**FEDERAL & STATE TAX CALCULATION**					
13						
14	OPERATING REVENUES		$52,902,507	$23,467,263	$51,626	$29,386,428
15	OPERATING EXPENSES					
16	OPERATION & MAINTENANCE EXP		25,116,748	7,549,077	4,808	17,565,675
17	DEPRECIATION		8,240,005	3,974,395	0	4,265,610
18	TAXES OTHER THAN INCOME		4,342,079	2,371,287	0	1,970,791
19	OPERATING INCOME BEFORE INCOME TAXES		15,203,676	9,572,503	46,817	5,584,353
20						
21	INTEREST EXPENSE		(5,821,563)	(3,544,955)	(15,731)	(2,260,877)
22						
23	BOOK TAXABLE INCOME		9,382,113	6,027,548	31,086	3,323,476
24						
25	STATE TAX @ 0.00%		0	0	0	0
26						
27	STATE AND FEDERAL TAXABLE BASIS		9,382,111	6,027,546	31,084	3,323,474
28						
29	STATE AND FEDERAL INCOME TAX @ 38.41%		3,603,671	2,315,182	11,939	1,276,547
30	AMORTIZATION OF ITC	PLANT	0	0	0	0
31	BLANK.	PLANT	0	0	0	0
32	TOTAL STATE AND FEDERAL TAXES		3,603,671	2,315,182	11,939	1,276,547
33						
34	TOTAL STATE & FEDERAL INCOME TAX		3,603,671	2,315,182	11,939	1,276,547
35						
36	NET INCOME AFTER TAX		$11,600,005	$7,257,321	$34,878	$4,307,806
37						
38						
39	EFFECTIVE STATE TAX RATE- Included in Federal		0.0000%	0.0000%	0.0000%	0.0000%
40	FEDERAL TAX RATE - CURRENT		38.4100%	38.4100%	38.4100%	38.4100%
41	UNCOLLECTIBLE FACTOR		0.4870%	0.4870%	0.4870%	0.4870%
42	1 - INCREMENTAL TAX RATE		0.618899	0.618899	0.618899	0.618899
43	FACTOR FOR TAXABLE BASIS		1.636600	1.636600	1.636600	1.636600
44	INTEREST EXPENSE PERCENTAGE		-3.19%	-3.19%	-3.19%	-3.19%
45	INCREMENTAL RETURN TAX RATE		1.6366	1.6366	1.6366	1.6366

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)	
	CLAIMED RATE OF RETURN SUMMARY SCHEDULE - COMPONENT FORMAT									
	RATE OF RETURN		9.54%	9.54%	9.54%	9.54%	9.54%	9.54%	9.54%	
	REVENUES REQUIRED									
1	**CAPACITY COMPONENTS**	29,352,429	29,352,429	16,261,857	6,699,106	3,798,156	2,532,150	30,518	30,642	
2	**PRODUCTION DEMAND COMP**		567,074	405,826	109,657	6,312	22,454	4,266	18,559	
3	PROD DEM GAS COST		567,074	405,826	109,657	6,312	22,454	4,266	18,559	
4										
5	**TRANSMISSION DEMAND COMP**		2,725,834	1,543,805	603,303	345,789	229,410	2,422	1,106	
6	TRANSMISSION PLANT		2,725,834	1,543,805	603,303	345,789	229,410	2,422	1,106	
7										
8	**DISTRIBUTION DEMAND COMP**	26,059,521	26,059,521	14,312,226	5,986,146	3,446,055	2,280,286	23,830	10,977	
9	DISTRIBUTION MAINS		22,721,752	12,365,966	5,283,667	3,031,328	2,009,931	21,174	9,685	
10	DISTRIBUTION REGULATORS		2,118,257	1,216,395	456,230	267,861	175,187	1,745	839	
11	DISTRIBUTION OTHER		1,219,512	729,865	246,249	146,865	95,168	911	454	
12										
13	**COMMODITY COMPONENTS**	218,724	218,724	185,245	17,403	6,678	6,063	703	2,632	0
14	COMMODITY GAS COST COMP		0	0	0	0	0	0	0	
15	COMMODITY OTHER COMP		218,724	185,245	17,403	6,678	6,063	703	2,632	
16										
17	**CUSTOMER COMPONENTS**	33,011,799	33,011,799	30,000,386	2,640,962	99,405	269,966	12	1,067	
18	CUST SERVICE DROP COMPONENT		13,385,843	12,220,829	1,062,633	2,676	99,262	0	443	
19	CUST METER COMPONENT		10,195,659	9,244,137	830,349	33,695	87,147	0	331	
20	CUST REGULATOR COMPONENT		1,242,251	1,044,943	116,993	60,524	19,790	0	(0)	
21	CUST DEPOSITS COMPONENT		149,562	149,564	(1)	0	0	0	(0)	
22	CUST MISC REV COMP		(1,060,447)	(1,006,492)	(52,849)	(161)	(944)	0	(0)	
23	CUST METER READING COMP		2,459,225	2,258,056	182,838	897	17,357	0	77	
24	CUST RECORDS & COLL COMP		6,151,680	5,630,817	474,252	1,685	44,727	0	199	
25	CUST SALES		488,026	458,532	26,748	90	2,626	12	18	
26	**TOTAL COMPANY**	62,582,951	62,582,951	46,447,487	9,357,472	3,904,239	2,808,179	31,233	34,341	
27										
28										
29	**TOTAL PRODUCTION**		785,798	591,070	127,060	12,990	28,516	4,969	21,191	
30										
31	**TOTAL DELIVERY SERVICE**		61,797,154	45,856,417	9,230,411	3,891,249	2,779,662	26,264	13,150	
32										
33	**TRAND & DISTR COMPONENT $/THERM**		$0.2099	$0.2215	$0.1957	$0.2841	$0.2104	$0.0220	$0.0022	
34										
35	**CUSTOMER COMPONENT $/MO/CUST**		$19.03	$18.93	$19.29	$217.99	$20.91	$0.20	$11.12	
36										
37	**TOTAL THRUPUT THERM**		137,141,116	71,600,398	33,670,786	13,348,945	11,931,026	1,192,130	5,397,831	
38										
39	**TOTAL ANNUAL CUSTOMERS**		144,571	132,036	11,408	38	1,076	5	8	
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			COMMERCIAL		INDUSTRIAL		PUBLIC AUTHORITY			
			SM. VOL.	LG. VOL.	SM. VOL.	LG. VOL.	SM. VOL.	LG. VOL.		
			(8)	(9)	(10)	(11)	(12)	(13)		
	CLAIMED RATE OF RETURN SUMMARY SCHEDULE - COMPONENT									
	RATE OF RETURN		9.54%	9.54%	9.54%	9.54%	9.54%	9.54%		
	REVENUES REQUIRED									
1	**CAPACITY COMPONENTS**	29,352,429	5,917,577	781,535	115,353	3,682,802	1,253,474	1,278,676		
2	**PRODUCTION DEMAND COMP**		104,821	4,836	1,974	4,338	18,336	4,118		
3	PROD DEM GAS COST		104,821	4,836	1,974	4,338	18,336	4,118		
4										
5	**TRANSMISSION DEMAND COMP**		532,276	71,026	10,368	335,420	113,080	116,330		
6	TRANSMISSION PLANT		532,276	71,026	10,368	335,420	113,080	116,330		
7										
8	**DISTRIBUTION DEMAND COMP**	26,059,521	5,280,479	705,670	103,011	3,343,044	1,122,058	1,158,228		
9	DISTRIBUTION MAINS		4,661,438	622,229	90,831	2,940,497	990,348	1,019,583		
10	DISTRIBUTION REGULATORS		402,131	54,099	7,897	259,965	85,535	89,652		
11	DISTRIBUTION OTHER		216,910	29,339	4,282	142,583	46,175	48,993		
12										
13	**COMMODITY COMPONENTS**	218,724	15,119	2,285	279	6,400	2,636	3,426	0	0
14	COMMODITY GAS COST COMP		0	0	0	0	0	0		
15	COMMODITY OTHER COMP		15,119	2,285	279	6,400	2,636	3,426		
16										
17	**CUSTOMER COMPONENTS**	33,011,799	2,557,682	83,290	34,437	64,968	232,754	37,212		
18	CUST SERVICE DROP COMPONENT		1,060,219	2,414	1,834	842	98,810	452		
19	CUST METER COMPONENT		789,911	40,437	1,376	32,318	73,696	13,451		
20	CUST REGULATOR COMPONENT		78,270	38,723	30,195	30,329	0	19,790		
21	CUST DEPOSITS COMPONENT		0	(1)	0	0	0	0		
22	CUST MISC REV COMP		(52,847)	(1)	(161)	0	(944)	0		
23	CUST METER READING COMP		182,246	592	319	579	17,011	346		
24	CUST RECORDS & COLL COMP		473,189	1,063	828	857	44,173	554		
25	CUST SALES		26,694	54	47	43	8	2,618		
26	**TOTAL COMPANY**	62,582,951	8,490,377	867,112	150,069	3,754,170	1,488,864	1,319,314		
27										
28										
29	**TOTAL PRODUCTION**		119,940	7,120	2,253	10,738	20,972	7,544		
30										
31	**TOTAL DELIVERY SERVICE**		8,370,437	859,986	147,816	3,743,432	1,467,892	1,311,770		
32										
33	**TRAND & DISTR COMPONENT $/THERM**		$0.1984	$0.1774	$0.2047	$0.2875	$0.2390	$0.1884		
34										
35	**CUSTOMER COMPONENT $/MO/CUST**		$18.72	$301.78	$143.49	$300.78	$6,465.39	$2.89		
36										
37	**TOTAL THRUPUT THERM**		29,291,657	4,379,129	553,766	12,795,179	5,167,584	6,763,442		
38										
39	**TOTAL ANNUAL CUSTOMERS**		11,385	23	20	18	3	1,073		
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			RESIDENTIAL				COMMERCIAL			
			RESIDENTIAL SERVICE	CARES			SM. VOL.	LG. VOL.	TRANS-PORTATION	
			(14)	(15)			(16)	(17)	(18)	
	CLAIMED RATE OF RETURN SUMMARY SCHEDULE - COMPONENT									
	RATE OF RETURN		9.54%	9.54%			9.54%	9.54%	9.54%	
	REVENUES REQUIRED									
1	**CAPACITY COMPONENTS**	29,352,429	14,908,585	755,018			5,917,577	261,885	519,650	
2	**PRODUCTION DEMAND COMP**		393,228	12,598			104,821	4,836	0	
3	PROD DEM GAS COST		393,228	12,598			104,821	4,836	0	
4										
5	**TRANSMISSION DEMAND COMP**		1,476,059	67,746			532,276	23,489	47,537	
6	TRANSMISSION PLANT		1,476,059	67,746			532,276	23,489	47,537	
7										
8	**DISTRIBUTION DEMAND COMP**	26,059,521	13,338,425	674,674			5,280,479	233,558	472,112	
9	DISTRIBUTION MAINS		11,772,165	593,801			4,661,438	205,817	416,412	
10	DISTRIBUTION REGULATORS		1,164,116	52,279			402,131	17,967	36,132	
11	DISTRIBUTION OTHER		701,271	28,594			216,910	9,771	19,568	
12										
13	**COMMODITY COMPONENTS**	218,724	183,532	1,712	0	0	15,119	673	1,611	0
14	COMMODITY GAS COST COMP		0	0			0	0	0	
15	COMMODITY OTHER COMP		183,532	1,712			15,119	673	1,611	
16										
17	**CUSTOMER COMPONENTS**	33,011,799	27,427,181	1,526,260			2,557,682	46,814	36,476	
18	CUST SERVICE DROP COMPONENT		11,584,368	636,460			1,060,219	2,414	0	
19	CUST METER COMPONENT		8,761,086	483,051			789,911	22,288	18,149	
20	CUST REGULATOR COMPONENT		997,586	47,357			78,270	21,263	17,461	
21	CUST DEPOSITS COMPONENT		149,564	0			0	(1)	0	
22	CUST MISC REV COMP		(944,789)	(61,704)			(52,847)	(1)	0	
23	CUST METER READING COMP		2,145,711	112,345			182,246	225	367	
24	CUST RECORDS & COLL COMP		5,338,534	292,283			473,189	586	477	
25	CUST SALES		442,065	16,467			26,694	32	22	
26	**TOTAL COMPANY**	62,582,951	42,220,170	2,282,989			8,490,377	309,375	557,737	
27										
28										
29	**TOTAL PRODUCTION**		576,760	14,310			119,940	5,509	1,611	
30										
31	**TOTAL DELIVERY SERVICE**		42,241,665	2,268,680			8,370,437	303,861	556,126	
32										
33	**TRAND & DISTR COMPONENT $/THERM**		$0.2176	$0.2101			$0.1984	$0.1921	$0.1709	
34										
35	**CUSTOMER COMPONENT $/MO/CUST**		$18.29	$17.97			$18.72	$278.65	$337.74	
36										
37	**TOTAL THRUPUT THERM**		68,066,962	3,533,436			29,291,657	1,338,244	3,040,885	
38										
39	**TOTAL ANNUAL CUSTOMERS**		124,959	7,077			11,385	14	9	
40										
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			INDUSTRIAL							
			SM. VOL.		LG. VOL.	TRANS-PORTATION				
			(19)		(20)	(21)				
	CLAIMED RATE OF RETURN SUMMARY SCHEDULE - COMPONENT									
	RATE OF RETURN		9.54%		9.54%	9.54%				
	REVENUES REQUIRED									
1	**CAPACITY COMPONENTS**	29,352,429	115,353		207,641	3,475,161				
2	**PRODUCTION DEMAND COMP**		1,974		4,338	0				
3	PROD DEM GAS COST		1,974		4,338	0				
4										
5	**TRANSMISSION DEMAND COMP**		10,368		18,549	316,872				
6	TRANSMISSION PLANT		10,368		18,549	316,872				
7										
8	**DISTRIBUTION DEMAND COMP**	26,059,521	103,011		184,754	3,158,290				
9	DISTRIBUTION MAINS		90,831		162,588	2,777,909				
10	DISTRIBUTION REGULATORS		7,897		14,326	245,638				
11	DISTRIBUTION OTHER		4,282		7,840	134,742				
12										
13	**COMMODITY COMPONENTS**	218,724	279	0	589	5,811	0	0	0	0
14	COMMODITY GAS COST COMP		0		0	0				
15	COMMODITY OTHER COMP		279		589	5,811				
16										
17	**CUSTOMER COMPONENTS**	33,011,799	34,437		16,353	48,615				
18	CUST SERVICE DROP COMPONENT		1,834		842	0				
19	CUST METER COMPONENT		1,376		7,834	24,484				
20	CUST REGULATOR COMPONENT		30,195		7,379	22,950				
21	CUST DEPOSITS COMPONENT		0		0	0				
22	CUST MISC REV COMP		(161)		0	0				
23	CUST METER READING COMP		319		80	499				
24	CUST RECORDS & COLL COMP		828		207	649				
25	CUST SALES		47		12	32				
26	**TOTAL COMPANY**	62,582,951	150,069		224,583	3,529,587				
27										
28										
29	**TOTAL PRODUCTION**		2,253		4,927	5,811				
30										
31	**TOTAL DELIVERY SERVICE**		147,816		219,657	3,523,776				
32										
33	**TRAND & DISTR COMPONENT $/THERM**		$0.2047		$0.1677	$0.3000				
34										
35	**CUSTOMER COMPONENT $/MO/CUST**		$143.49		$272.56	$311.63				
36										
37	**TOTAL THRUPUT THERM**		553,766		1,212,653	11,582,526				
38										
39	**TOTAL ANNUAL CUSTOMERS**		20		5	13				
40										
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

	CLAIMED RATE OF RETURN SUMMARY SCHEDULE - COMPONENT		PUBLIC AUTHORITY SM. VOL. (22)		PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)		SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
	RATE OF RETURN		9.54%		9.54%	9.54%		9.54%	9.54%
	REVENUES REQUIRED								
1	**CAPACITY COMPONENTS**	29,352,429	1,253,474		243,367	1,035,309		30,518	30,642
2	**PRODUCTION DEMAND COMP**		18,336		4,118	0		4,266	18,559
3	PROD DEM GAS COST		18,336		4,118	0		4,266	18,559
4									
5	**TRANSMISSION DEMAND COMP**		113,080		21,836	94,494		2,422	1,106
6	TRANSMISSION PLANT		113,080		21,836	94,494		2,422	1,106
7									
8	**DISTRIBUTION DEMAND COMP**	26,059,521	1,122,058		217,413	940,814		23,830	10,977
9	DISTRIBUTION MAINS		990,348		191,383	828,200		21,174	9,685
10	DISTRIBUTION REGULATORS		85,535		16,831	72,821		1,745	839
11	DISTRIBUTION OTHER		46,175		9,199	39,794		911	454
12									
13	**COMMODITY COMPONENTS**	218,724	2,636	0	562	2,864	0	703	2,632
14	COMMODITY GAS COST COMP		0		0	0		0	0
15	COMMODITY OTHER COMP		2,636		562	2,864		703	2,632
16									
17	**CUSTOMER COMPONENTS**	33,011,799	232,754		8,493	28,720		12	1,067
18	CUST SERVICE DROP COMPONENT		98,810		452	0		0	443
19	CUST METER COMPONENT		73,696		343	13,108		0	331
20	CUST REGULATOR COMPONENT		0		7,408	12,383		0	(0)
21	CUST DEPOSITS COMPONENT		0		0	0		0	(0)
22	CUST MISC REV COMP		(944)		0	0		0	(0)
23	CUST METER READING COMP		17,011		80	267		0	77
24	CUST RECORDS & COLL COMP		44,173		207	347		0	199
25	CUST SALES		8		2	2,616		12	18
26	**TOTAL COMPANY**	62,582,951	1,488,864		252,422	1,066,892		31,233	34,341
27									
28									
29	**TOTAL PRODUCTION**		20,972		4,680	2,864		4,969	21,191
30									
31	**TOTAL DELIVERY SERVICE**		1,467,892		247,742	1,064,028		26,264	13,150
32									
33	**TRAND & DISTR COMPONENT $/THERM**		$0.2390		$0.2078	$0.1845		$0.0220	$0.0022
34									
35	**CUSTOMER COMPONENT $/MO/CUST**		$6,465.39		$707.72	$2.23		$0.20	$11.12
36									
37	**TOTAL THRUPUT THERM**		5,167,584		1,151,133	5,612,308		1,192,130	5,397,831
38									
39	**TOTAL ANNUAL CUSTOMERS**		3		1	1,072		5	8
40									
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

CLAIMED RATE OF RETURN SUMMARY SCHEDULE - FUNCTION FORMAT

			TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
	RATE OF RETURN		9.54%	9.54%	9.54%	9.54%	9.54%	9.54%	9.54%
	$/THERM								
1	**CAPACITY COMPONENTS**	0.2118	0.2097	0.2188	0.1990	0.2845	0.2122	0.0256	0.0057
2	**PRODUCTION DEMAND COMP**		0.0041	0.0057	0.0033	0.0005	0.0019	0.0036	0.0034
3	PROD DEM GAS COST		0.0041	0.0057	0.0033	0.0005	0.0019	0.0036	0.0034
4									
5	**TRANSMISSION DEMAND COMP**		0.0199	0.0216	0.0179	0.0259	0.0192	0.0020	0.0002
6	TRANSMISSION PLANT		0.0199	0.0216	0.0179	0.0259	0.0192	0.0020	0.0002
7									
8	**DISTRIBUTION DEMAND COMP**	0.1900	0.1878	0.1957	0.1778	0.2582	0.1911	0.0200	0.0020
9	DISTRIBUTION MAINS		0.1657	0.1727	0.1569	0.2271	0.1685	0.0178	0.0018
10	DISTRIBUTION REGULATORS		0.0154	0.0170	0.0135	0.0201	0.0147	0.0015	0.0002
11	DISTRIBUTION OTHER		0.0089	0.0102	0.0073	0.0110	0.0080	0.0008	0.0001
12									
13	**COMMODITY COMPONENTS**	0.0027	0.0016	0.0026	0.0005	0.0005	0.0005	0.0006	0.0005
14	COMMODITY GAS COST COMP		0.0011	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000
15	COMMODITY OTHER COMP		0.0016	0.0026	0.0005	0.0005	0.0005	0.0006	0.0005
16									
17	**CUSTOMER COMPONENTS**	0.2407	0.2331	0.4044	0.0784	0.0074	0.0226	0.0000	0.0002
18	CUST SERVICE DROP COMPONENT		0.0976	0.1707	0.0316	0.0002	0.0083	0.0000	0.0001
19	CUST METER COMPONENT		0.0743	0.1291	0.0247	0.0025	0.0073	0.0000	0.0001
20	CUST REGULATOR COMPONENT		0.0091	0.0146	0.0035	0.0045	0.0017	0.0000	0.0000
21	CUST DEPOSITS COMPONENT		0.0011	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000
22	CUST MISC REV COMP		-0.0077	-0.0141	-0.0016	0.0000	-0.0001	0.0000	0.0000
23	CUST METER READING COMP		0.0179	0.0315	0.0054	0.0001	0.0015	0.0000	0.0000
24	CUST RECORDS & COLL COMP		0.0449	0.0786	0.0141	0.0001	0.0037	0.0000	0.0000
25	CUST SALES		0.0036	0.0064	0.0008	0.0000	0.0002	0.0000	0.0000
26	**TOTAL COMPANY**		0.4422	0.6215	0.2779	0.2925	0.2354	0.0262	0.0064
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			COMMERCIAL		INDUSTRIAL		PUBLIC AUTHORITY	
			SM. VOL. (8)	LG. VOL. (9)	SM. VOL. (10)	LG. VOL. (11)	SM. VOL. (12)	LG. VOL. (13)
	CLAIMED RATE OF RETURN SUMMARY SCHEDULE - FUNCTION FO							
	RATE OF RETURN		9.54%	9.54%	9.54%	9.54%	9.54%	9.54%
	$/THERM							
1	**CAPACITY COMPONENTS**	0.2118	0.2020	0.1785	0.2083	0.2878	0.2426	0.1891
2	**PRODUCTION DEMAND COMP**		0.0036	0.0011	0.0036	0.0003	0.0035	0.0006
3	PROD DEM GAS COST		0.0036	0.0011	0.0036	0.0003	0.0035	0.0006
4								
5	**TRANSMISSION DEMAND COMP**		0.0182	0.0162	0.0187	0.0262	0.0219	0.0172
6	TRANSMISSION PLANT		0.0182	0.0162	0.0187	0.0262	0.0219	0.0172
7								
8	**DISTRIBUTION DEMAND COMP**	0.1900	0.1803	0.1611	0.1860	0.2613	0.2171	0.1712
9	DISTRIBUTION MAINS		0.1591	0.1421	0.1640	0.2298	0.1916	0.1507
10	DISTRIBUTION REGULATORS		0.0137	0.0124	0.0143	0.0203	0.0166	0.0133
11	DISTRIBUTION OTHER		0.0074	0.0067	0.0077	0.0111	0.0089	0.0072
12								
13	**COMMODITY COMPONENTS**	0.0027	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
14	COMMODITY GAS COST COMP		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
15	COMMODITY OTHER COMP		0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
16								
17	**CUSTOMER COMPONENTS**	0.2407	0.0873	0.0190	0.0622	0.0051	0.0450	0.0055
18	CUST SERVICE DROP COMPONENT		0.0362	0.0006	0.0033	0.0001	0.0191	0.0001
19	CUST METER COMPONENT		0.0270	0.0092	0.0025	0.0025	0.0143	0.0020
20	CUST REGULATOR COMPONENT		0.0027	0.0088	0.0545	0.0024	0.0000	0.0029
21	CUST DEPOSITS COMPONENT		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
22	CUST MISC REV COMP		-0.0018	0.0000	-0.0003	0.0000	-0.0002	0.0000
23	CUST METER READING COMP		0.0062	0.0001	0.0006	0.0000	0.0033	0.0001
24	CUST RECORDS & COLL COMP		0.0162	0.0002	0.0015	0.0001	0.0085	0.0001
25	CUST SALES		0.0009	0.0000	0.0001	0.0000	0.0000	0.0004
26	**TOTAL COMPANY**		0.2899	0.1980	0.2710	0.2934	0.2881	0.1951
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
	CLAIMED RATE OF RETURN SUMMARY SCHEDULE - FUNCTION FO						
	RATE OF RETURN		9.54%	9.54%	9.54%	9.54%	9.54%
	$/THERM						
1	**CAPACITY COMPONENTS**	0.2118	0.2190	0.2137	0.2020	0.1957	0.1709
2	***PRODUCTION DEMAND COMP***		0.0058	0.0036	0.0036	0.0036	0.0000
3	PROD DEM GAS COST		0.0058	0.0036	0.0036	0.0036	0.0000
4							
5	**TRANSMISSION DEMAND COMP**		0.0217	0.0192	0.0182	0.0176	0.0156
6	TRANSMISSION PLANT		0.0217	0.0192	0.0182	0.0176	0.0156
7							
8	**DISTRIBUTION DEMAND COMP**	0.1900	0.1960	0.1909	0.1803	0.1745	0.1553
9	DISTRIBUTION MAINS		0.1729	0.1681	0.1591	0.1538	0.1369
10	DISTRIBUTION REGULATORS		0.0171	0.0148	0.0137	0.0134	0.0119
11	DISTRIBUTION OTHER		0.0103	0.0081	0.0074	0.0073	0.0064
12							
13	**COMMODITY COMPONENTS**	0.0027	0.0027	0.0005	0.0005	0.0005	0.0005
14	COMMODITY GAS COST COMP		0.0022	0.0000	0.0000	0.0000	0.0000
15	COMMODITY OTHER COMP		0.0027	0.0005	0.0005	0.0005	0.0005
16							
17	**CUSTOMER COMPONENTS**	0.2407	0.4029	0.4319	0.0873	0.0350	0.0120
18	CUST SERVICE DROP COMPONENT		0.1702	0.1801	0.0362	0.0018	0.0000
19	CUST METER COMPONENT		0.1287	0.1367	0.0270	0.0167	0.0060
20	CUST REGULATOR COMPONENT		0.0147	0.0134	0.0027	0.0159	0.0057
21	CUST DEPOSITS COMPONENT		0.0022	0.0000	0.0000	0.0000	0.0000
22	CUST MISC REV COMP		-0.0139	-0.0175	-0.0018	0.0000	0.0000
23	CUST METER READING COMP		0.0315	0.0318	0.0062	0.0002	0.0001
24	CUST RECORDS & COLL COMP		0.0784	0.0827	0.0162	0.0004	0.0002
25	CUST SALES		0.0065	0.0047	0.0009	0.0000	0.0000
26	**TOTAL COMPANY**		0.6203	0.6461	0.2899	0.2312	0.1834
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			INDUSTRIAL		
			SM. VOL.	LG. VOL.	TRANS-PORTATION
			(19)	(20)	(21)
	CLAIMED RATE OF RETURN SUMMARY SCHEDULE - FUNCTION FO				
	RATE OF RETURN		9.54%	9.54%	9.54%
	$/THERM				
1	**CAPACITY COMPONENTS**	0.2118	0.2083	0.1712	0.3000
2	**PRODUCTION DEMAND COMP**		0.0036	0.0036	0.0000
3	PROD DEM GAS COST		0.0036	0.0036	0.0000
4					
5	**TRANSMISSION DEMAND COMP**		0.0187	0.0153	0.0274
6	TRANSMISSION PLANT		0.0187	0.0153	0.0274
7					
8	**DISTRIBUTION DEMAND COMP**	0.1900	0.1860	0.1524	0.2727
9	DISTRIBUTION MAINS		0.1640	0.1341	0.2398
10	DISTRIBUTION REGULATORS		0.0143	0.0118	0.0212
11	DISTRIBUTION OTHER		0.0077	0.0065	0.0116
12					
13	**COMMODITY COMPONENTS**	0.0027	0.0005	0.0005	0.0005
14	COMMODITY GAS COST COMP		0.0000	0.0000	0.0000
15	COMMODITY OTHER COMP		0.0005	0.0005	0.0005
16					
17	**CUSTOMER COMPONENTS**	0.2407	0.0622	0.0135	0.0042
18	CUST SERVICE DROP COMPONENT		0.0033	0.0007	0.0000
19	CUST METER COMPONENT		0.0025	0.0065	0.0021
20	CUST REGULATOR COMPONENT		0.0545	0.0061	0.0020
21	CUST DEPOSITS COMPONENT		0.0000	0.0000	0.0000
22	CUST MISC REV COMP		-0.0003	0.0000	0.0000
23	CUST METER READING COMP		0.0006	0.0001	0.0000
24	CUST RECORDS & COLL COMP		0.0015	0.0002	0.0001
25	CUST SALES		0.0001	0.0000	0.0000
26	**TOTAL COMPANY**		0.2710	0.1852	0.3047
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			PUBLIC AUTHORITY				
			SM. VOL.	LG. VOL.	TRANS-PORTATION	SPECIAL GAS LIGHT SERVICE	IRRIGATION
			(22)	(23)	(24)	(25)	(26)
	CLAIMED RATE OF RETURN SUMMARY SCHEDULE - FUNCTION FO						
	RATE OF RETURN		9.54%	9.54%	9.54%	9.54%	9.54%
	$/THERM						
1	**CAPACITY COMPONENTS**	0.2118	0.2426	0.2114	0.1845	0.0256	0.0057
2	**PRODUCTION DEMAND COMP**		0.0035	0.0036	0.0000	0.0036	0.0034
3	PROD DEM GAS COST		0.0035	0.0036	0.0000	0.0036	0.0034
4							
5	**TRANSMISSION DEMAND COMP**		0.0219	0.0190	0.0168	0.0020	0.0002
6	TRANSMISSION PLANT		0.0219	0.0190	0.0168	0.0020	0.0002
7							
8	**DISTRIBUTION DEMAND COMP**	0.1900	0.2171	0.1889	0.1676	0.0200	0.0020
9	DISTRIBUTION MAINS		0.1916	0.1663	0.1476	0.0178	0.0018
10	DISTRIBUTION REGULATORS		0.0166	0.0146	0.0130	0.0015	0.0002
11	DISTRIBUTION OTHER		0.0089	0.0080	0.0071	0.0008	0.0001
12							
13	**COMMODITY COMPONENTS**	0.0027	0.0005	0.0005	0.0005	0.0006	0.0005
14	COMMODITY GAS COST COMP		0.0000	0.0000	0.0000	0.0000	0.0000
15	COMMODITY OTHER COMP		0.0005	0.0005	0.0005	0.0006	0.0005
16							
17	**CUSTOMER COMPONENTS**	0.2407	0.0450	0.0074	0.0051	0.0000	0.0002
18	CUST SERVICE DROP COMPONENT		0.0191	0.0004	0.0000	0.0000	0.0001
19	CUST METER COMPONENT		0.0143	0.0003	0.0023	0.0000	0.0001
20	CUST REGULATOR COMPONENT		0.0000	0.0064	0.0022	0.0000	0.0000
21	CUST DEPOSITS COMPONENT		0.0000	0.0000	0.0000	0.0000	0.0000
22	CUST MISC REV COMP		-0.0002	0.0000	0.0000	0.0000	0.0000
23	CUST METER READING COMP		0.0033	0.0001	0.0000	0.0000	0.0000
24	CUST RECORDS & COLL COMP		0.0085	0.0002	0.0001	0.0000	0.0000
25	CUST SALES		0.0000	0.0000	0.0005	0.0000	0.0000
26	**TOTAL COMPANY**		0.2881	0.2193	0.1901	0.0262	0.0064
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1) (0)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	DEVELOPMENT OF LABOR ALLOCATOR								
2									
3	**EXPENSED LABOR**								
4	PRODUCTION LABOR								
5	421-PURCHASED POWER	EXP421	0	0	0	0	0	0	0
6	805-PURCHASED GAS EXPENSE	EXP805	0	0	0	0	0	0	0
7	807-PURCHASED GAS COST EXPENSES								
8	DEMAND RELATED	EXP807D	0	0	0	0	0	0	0
9	COMMODITY RELATED	EXP807C	0	0	0	0	0	0	0
10	TOTAL ACCOUNT 807		0	0	0	0	0	0	0
11	TOTAL PURCHASED GAS SUPPLY		0	0	0	0	0	0	0
12									
13	TRANSMISSION LABOR								
14	856-MAINS EXPENSE	EXP856	9,902	5,411	2,286	1,317	875	8	4
15	857-MEASURING & REG. STATION	EXP857	0	0	0	0	0	0	0
16	864-MAINT. OF STATION EQUIP.	EXP864	0	0	0	0	0	0	0
17	867-MAINT. OF OTHER EQUIP.	EXP867	0	0	0	0	0	0	0
18	TOTAL TRANSMISSION LABOR		9,902	5,411	2,286	1,317	875	8	4
19									
20	DISTRIBUTION LABOR								
21	870-OPERATION SUPERV. & ENG.	LABDO	268,584	213,692	34,338	11,580	8,860	71	43
22	871-LOAD DISPATCHING	EXP871	0	0	0	0	0	0	0
23	874-MAINS & SERVICING EXPENSE	EXP874	1,106,445	752,333	194,292	93,698	65,193	601	328
24	875-MEAS./REG. STATION EXPENSE	EXP875	142,569	77,903	32,919	18,964	12,598	122	64
25	876-MEAS./REG. STATION EXPENSE	EXP876	130,857	71,503	30,215	17,406	11,563	112	58
26	877-MEAS./REG. STATION EXPENSE	EXP877	21,280	19,590	1,689	0	0	0	0
27	878-METER EXPENSE	EXP878	1,131,412	1,025,064	92,825	3,705	9,780	0	39
28	879-CUSTOMER INSTALL EXP	EXP879	636,661	578,107	51,999	1,796	4,740	0	19
29	880-OTHER EXPENSES	EXP880	509,833	402,640	66,417	23,060	17,488	142	86
30	881-RENTS	EXP881	0	0	0	0	0	0	0
31	885-MAINT. SUPERV. & ENG.	LABDM	176,301	127,295	27,889	12,253	8,742	78	44
32	886-MAINT. OF STRUCTURES	EXP886	0	0	0	0	0	0	0
33	887-MAINT. OF MAINS	EXP887	493,797	269,821	114,017	65,682	43,636	421	220
34	889-MAINT. MEAS./REG	EXP889	12,111	6,618	2,796	1,611	1,070	10	5
35	890-MAINT. MEAS./REG	EXP890	0	0	0	0	0	0	0
36	891-MAINT. MEAS./REG	EXP891	2,131	1,962	169	0	0	0	0
37	892-MAINT. OF SERVICES	EXP892	368,420	336,506	29,082	75	2,744	0	13
38	893-MAINT. OF METER	EXP893	102,102	92,505	8,377	334	883	0	4
39	894-MAINT. OF OTHER EQUIP.	EXP894	4,892	2,673	1,129	651	432	4	2
40	TOTAL DISTRIBUTION LABOR		5,107,395	3,978,212	688,152	250,815	187,729	1,562	925
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	DEVELOPMENT OF LABOR ALLOCATOR							
2								
3	**EXPENSED LABOR**							
4	PRODUCTION LABOR							
5	421-PURCHASED POWER	EXP421	0	0	0	0	0	0
6	805-PURCHASED GAS EXPENSE	EXP805	0	0	0	0	0	0
7	807-PURCHASED GAS COST EXPENSES							
8	DEMAND RELATED	EXP807D	0	0	0	0	0	0
9	COMMODITY RELATED	EXP807C	0	0	0	0	0	0
10	TOTAL ACCOUNT 807		0	0	0	0	0	0
11	TOTAL PURCHASED GAS SUPPLY		0	0	0	0	0	0
12								
13	TRANSMISSION LABOR							
14	856-MAINS EXPENSE	EXP856	2,021	265	40	1,277	434	441
15	857-MEASURING & REG. STATION	EXP857	0	0	0	0	0	0
16	864-MAINT. OF STATION EQUIP.	EXP864	0	0	0	0	0	0
17	867-MAINT. OF OTHER EQUIP.	EXP867	0	0	0	0	0	0
18	TOTAL TRANSMISSION LABOR		2,021	265	40	1,277	434	441
19								
20	DISTRIBUTION LABOR							
21	870-OPERATION SUPERV. & ENG.	LABDO	31,542	2,796	362	11,218	4,956	3,904
22	871-LOAD DISPATCHING	EXP871	0	0	0	0	0	0
23	874-MAINS & SERVICING EXPENSE	EXP874	175,391	18,901	2,903	90,795	33,829	31,364
24	875-MEAS./REG. STATION EXPENSE	EXP875	29,105	3,814	577	18,387	6,248	6,350
25	876-MEAS./REG. STATION EXPENSE	EXP876	26,714	3,501	529	16,876	5,735	5,829
26	877-MEAS./REG. STATION EXPENSE	EXP877	1,689	0	0	0	0	0
27	878-METER EXPENSE	EXP878	88,387	4,437	155	3,550	8,321	1,459
28	879-CUSTOMER INSTALL EXP	EXP879	49,848	2,151	75	1,720	4,033	707
29	880-OTHER EXPENSES	EXP880	60,923	5,494	720	22,340	9,717	7,770
30	881-RENTS	EXP881	0	0	0	0	0	0
31	885-MAINT. SUPERV. & ENG.	LABDM	25,355	2,533	382	11,871	4,637	4,105
32	886-MAINT. OF STRUCTURES	EXP886	0	0	0	0	0	0
33	887-MAINT. OF MAINS	EXP887	100,807	13,210	1,998	63,684	21,640	21,995
34	889-MAINT. MEAS./REG	EXP889	2,472	324	49	1,562	531	539
35	890-MAINT. MEAS./REG	EXP890	0	0	0	0	0	0
36	891-MAINT. MEAS./REG	EXP891	169	0	0	0	0	0
37	892-MAINT. OF SERVICES	EXP892	29,016	67	51	24	2,732	13
38	893-MAINT. OF METER	EXP893	7,976	400	14	320	751	132
39	894-MAINT. OF OTHER EQUIP.	EXP894	999	131	20	631	214	218
40	TOTAL DISTRIBUTION LABOR		630,395	57,757	7,836	242,979	103,345	84,385
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	DEVELOPMENT OF LABOR ALLOCATOR						
2							
3	**EXPENSED LABOR**						
4	PRODUCTION LABOR						
5	421-PURCHASED POWER	EXP421	0	0	0	0	0
6	805-PURCHASED GAS EXPENSE	EXP805	0	0	0	0	0
7	807-PURCHASED GAS COST EXPENSES						
8	DEMAND RELATED	EXP807D	0	0	0	0	0
9	COMMODITY RELATED	EXP807C	0	0	0	0	0
10	TOTAL ACCOUNT 807		0	0	0	0	0
11	TOTAL PURCHASED GAS SUPPLY		0	0	0	0	0
12							
13	TRANSMISSION LABOR						
14	856-MAINS EXPENSE	EXP856	5,143	268	2,021	90	175
15	857-MEASURING & REG. STATION	EXP857	0	0	0	0	0
16	864-MAINT. OF STATION EQUIP.	EXP864	0	0	0	0	0
17	867-MAINT. OF OTHER EQUIP.	EXP867	0	0	0	0	0
18	TOTAL TRANSMISSION LABOR		5,143	268	2,021	90	175
19							
20	DISTRIBUTION LABOR						
21	870-OPERATION SUPERV. & ENG.	LABDO	202,425	11,267	31,542	1,077	1,718
22	871-LOAD DISPATCHING	EXP871	0	0	0	0	0
23	874-MAINS & SERVICING EXPENSE	EXP874	713,583	38,751	175,391	6,479	12,421
24	875-MEAS./REG. STATION EXPENSE	EXP875	74,046	3,857	29,105	1,298	2,516
25	876-MEAS./REG. STATION EXPENSE	EXP876	67,963	3,540	26,714	1,191	2,309
26	877-MEAS./REG. STATION EXPENSE	EXP877	18,540	1,050	1,689	0	0
27	878-METER EXPENSE	EXP878	970,121	54,942	88,387	2,485	1,952
28	879-CUSTOMER INSTALL EXP	EXP879	547,122	30,986	49,848	1,204	946
29	880-OTHER EXPENSES	EXP880	381,432	21,208	60,923	2,101	3,393
30	881-RENTS	EXP881	0	0	0	0	0
31	885-MAINT. SUPERV. & ENG.	LABDM	120,677	6,618	25,355	886	1,648
32	886-MAINT. OF STRUCTURES	EXP886	0	0	0	0	0
33	887-MAINT. OF MAINS	EXP887	256,463	13,358	100,807	4,495	8,715
34	889-MAINT. MEAS./REG	EXP889	6,290	328	2,472	110	214
35	890-MAINT. MEAS./REG	EXP890	0	0	0	0	0
36	891-MAINT. MEAS./REG	EXP891	1,857	105	169	0	0
37	892-MAINT. OF SERVICES	EXP892	318,470	18,036	29,016	67	0
38	893-MAINT. OF METER	EXP893	87,547	4,958	7,976	224	176
39	894-MAINT. OF OTHER EQUIP.	EXP894	2,541	132	999	45	86
40	TOTAL DISTRIBUTION LABOR		3,769,076	209,136	630,395	21,662	36,095
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	DEVELOPMENT OF LABOR ALLOCATOR				
2					
3	**EXPENSED LABOR**				
4	PRODUCTION LABOR				
5	421-PURCHASED POWER	EXP421	0	0	0
6	805-PURCHASED GAS EXPENSE	EXP805	0	0	0
7	807-PURCHASED GAS COST EXPENSES				
8	DEMAND RELATED	EXP807D	0	0	0
9	COMMODITY RELATED	EXP807C	0	0	0
10	TOTAL ACCOUNT 807		0	0	0
11	TOTAL PURCHASED GAS SUPPLY		0	0	0
12					
13	TRANSMISSION LABOR				
14	856-MAINS EXPENSE	EXP856	40	73	1,204
15	857-MEASURING & REG. STATION	EXP857	0	0	0
16	864-MAINT. OF STATION EQUIP.	EXP864	0	0	0
17	867-MAINT. OF OTHER EQUIP.	EXP867	0	0	0
18	TOTAL TRANSMISSION LABOR		40	73	1,204
19					
20	DISTRIBUTION LABOR				
21	870-OPERATION SUPERV. & ENG.	LABDO	362	730	10,488
22	871-LOAD DISPATCHING	EXP871	0	0	0
23	874-MAINS & SERVICING EXPENSE	EXP874	2,903	5,223	85,572
24	875-MEAS./REG. STATION EXPENSE	EXP875	577	1,053	17,334
25	876-MEAS./REG. STATION EXPENSE	EXP876	529	966	15,910
26	877-MEAS./REG. STATION EXPENSE	EXP877	0	0	0
27	878-METER EXPENSE	EXP878	155	887	2,662
28	879-CUSTOMER INSTALL EXP	EXP879	75	430	1,290
29	880-OTHER EXPENSES	EXP880	720	1,440	20,900
30	881-RENTS	EXP881	0	0	0
31	885-MAINT. SUPERV. & ENG.	LABDM	382	695	11,176
32	886-MAINT. OF STRUCTURES	EXP886	0	0	0
33	887-MAINT. OF MAINS	EXP887	1,998	3,646	60,038
34	889-MAINT. MEAS./REG	EXP889	49	89	1,473
35	890-MAINT. MEAS./REG	EXP890	0	0	0
36	891-MAINT. MEAS./REG	EXP891	0	0	0
37	892-MAINT. OF SERVICES	EXP892	51	24	0
38	893-MAINT. OF METER	EXP893	14	80	240
39	894-MAINT. OF OTHER EQUIP.	EXP894	20	36	595
40	TOTAL DISTRIBUTION LABOR		7,836	15,300	227,679
41					
42					
43					
44					
45					

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	DEVELOPMENT OF LABOR ALLOCATOR						
2							
3	**EXPENSED LABOR**						
4	PRODUCTION LABOR						
5	421-PURCHASED POWER	EXP421	0	0	0	0	0
6	805-PURCHASED GAS EXPENSE	EXP805	0	0	0	0	0
7	807-PURCHASED GAS COST EXPENSES						
8	DEMAND RELATED	EXP807D	0	0	0	0	0
9	COMMODITY RELATED	EXP807C	0	0	0	0	0
10	TOTAL ACCOUNT 807		0	0	0	0	0
11	TOTAL PURCHASED GAS SUPPLY		0	0	0	0	0
12							
13	TRANSMISSION LABOR						
14	856-MAINS EXPENSE	EXP856	434	86	355	8	4
15	857-MEASURING & REG. STATION	EXP857	0	0	0	0	0
16	864-MAINT. OF STATION EQUIP.	EXP864	0	0	0	0	0
17	867-MAINT. OF OTHER EQUIP.	EXP867	0	0	0	0	0
18	TOTAL TRANSMISSION LABOR		434	86	355	8	4
19							
20	DISTRIBUTION LABOR						
21	870-OPERATION SUPERV. & ENG.	LABDO	4,956	730	3,175	71	43
22	871-LOAD DISPATCHING	EXP871	0	0	0	0	0
23	874-MAINS & SERVICING EXPENSE	EXP874	33,829	6,111	25,253	601	328
24	875-MEAS./REG. STATION EXPENSE	EXP875	6,248	1,235	5,115	122	64
25	876-MEAS./REG. STATION EXPENSE	EXP876	5,735	1,134	4,695	112	58
26	877-MEAS./REG. STATION EXPENSE	EXP877	0	0	0	0	0
27	878-METER EXPENSE	EXP878	8,321	39	1,420	0	39
28	879-CUSTOMER INSTALL EXP	EXP879	4,033	19	688	0	19
29	880-OTHER EXPENSES	EXP880	9,717	1,457	6,313	142	86
30	881-RENTS	EXP881	0	0	0	0	0
31	885-MAINT. SUPERV. & ENG.	LABDM	4,637	796	3,309	78	44
32	886-MAINT. OF STRUCTURES	EXP886	0	0	0	0	0
33	887-MAINT. OF MAINS	EXP887	21,640	4,277	17,718	421	220
34	889-MAINT. MEAS./REG	EXP889	531	105	435	10	5
35	890-MAINT. MEAS./REG	EXP890	0	0	0	0	0
36	891-MAINT. MEAS./REG	EXP891	0	0	0	0	0
37	892-MAINT. OF SERVICES	EXP892	2,732	13	0	0	13
38	893-MAINT. OF METER	EXP893	751	4	128	0	4
39	894-MAINT. OF OTHER EQUIP.	EXP894	214	42	176	4	2
40	TOTAL DISTRIBUTION LABOR		103,345	15,960	68,425	1,562	925
41							
42							
43							
44							
45							

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	DEVEL OF LABOR ALLOC CON'T.								
2	**EXPENSED LABOR CONTINUED**								
3	CUSTOMER ACCOUNT LABOR								
4	901-SUPERVISION	LABCA	34,768	31,748	2,745	12	262	0	1
5	902-METER READING EXPENSE	EXP902	676,938	618,078	53,463	257	5,116	0	23
6	903-CUST RECORDS & COLLECT	EXP903	945,972	863,923	74,656	262	7,098	0	33
7	904-UNCOLLECTIBLE ACCOUNTS	EXP904	0	0	0	0	0	0	0
8	905-MISC CUST ACCTS EXP	EXP905	1,845	1,609	163	46	26	0	0
9	906-CUSTOMER SERVICE & INFO	EXP906	0	0	0	0	0	0	0
10	907-SUPERV. CUSTOMER SERV.	LABCS	0	0	0	0	0	0	0
11	908-CUSTOMER ASSISTANCE	EXP908	67,190	61,364	5,302	18	500	2	4
12	909-INFO & INSTRUCTIONAL ADVERT.	EXP909	18,101	16,532	1,428	5	135	1	1
13	910-MISC. CUST. SERV. & INFO.	EXP910	0	0	0	0	0	0	0
14	TOTAL CUSTOMER ACCTS LABOR		1,744,813	1,593,253	137,758	600	13,136	3	62
15									
16	SALES LABOR								
17	912-DEMONSTRATING & SELLING	EXP912	0	0	0	0	0	0	0
18	913-ADVERTISING EXPENSES	EXP913	0	0	0	0	0	0	0
19	TOTAL SALES LABOR		0	0	0	0	0	0	0
20									
21	ADMINISTRATIVE & GENERAL LABOR								
22	920-ADMIN & GENERAL SALARY	EXP920	2,650,446	2,154,032	319,886	97,616	77,921	608	383
23	921-OFFICE SUPPLIES & EXP	EXP921	0	0	0	0	0	0	0
24	923-OUTSIDE SERV EMPLOYED	EXP923	0	0	0	0	0	0	0
25	924-PROPERTY INSURANCE	EXP924	0	0	0	0	0	0	0
26	925-INJURIES & DAMAGES	EXP925	21,755	17,681	2,626	801	640	5	3
27	926-EMPLOYED PENSION & BENF	EXP926	102,325	83,160	12,350	3,769	3,008	23	15
28	928-REGULATORY COMM EXPENSE	EXP928	0	0	0	0	0	0	0
29	930-MISCELLANEOUS GEN EXP	EXP930	30,746	24,987	3,711	1,132	904	7	4
30	931-RENTS	EXP931	0	0	0	0	0	0	0
31	932-MAINT OF GENERAL PLT	EXP932	12,210	9,923	1,474	450	359	3	2
32	TOTAL ADMIN & GEN LABOR		2,817,481	2,289,783	340,045	103,768	82,832	646	407
33									
34	**CAPITALIZED LABOR**								
35	371	CAPLABX	0	0	0	0	0	0	0
36	376-MAINS	PLT376	0	0	0	0	0	0	0
37	378-MEAS. & REG. EQUIP-GEN	PLT378	0	0	0	0	0	0	0
38	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	0	0	0	0	0	0	0
39	380-SERVICES	PLT380	0	0	0	0	0	0	0
40	382-METER INSTALLATIONS	PLT382	0	0	0	0	0	0	0
41	384-REGULATOR INSTALLATIONS	PLT384	0	0	0	0	0	0	0
42	385-INDUSTRIAL MEAS. EQUIP.	PLT385	0	0	0	0	0	0	0
43	387-OTHER EQUIPMENT	PLT387	0	0	0	0	0	0	0
44	390-STRUCTURES & IMPROVE.	PLT390	0	0	0	0	0	0	0
45	391-OFFICE FURN & EQUIP	PLT391	0	0	0	0	0	0	0
46	TOTAL CAPITALIZED LABOR		0	0	0	0	0	0	0
47									
48	SUM OF ALLOCATED LABOR EXP		9,679,590	7,866,658	1,168,242	356,499	284,573	2,219	1,399

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	DEVEL OF LABOR ALLOC CON'T.							
2	**EXPENSED LABOR CONTINUED**							
3	CUSTOMER ACCOUNT LABOR							
4	901-SUPERVISION	LABCA	2,738	7	5	7	258	4
5	902-METER READING EXPENSE	EXP902	53,295	169	94	164	5,017	98
6	903-CUST RECORDS & COLLECT	EXP903	74,493	164	131	131	7,013	85
7	904-UNCOLLECTIBLE ACCOUNTS	EXP904	0	0	0	0	0	0
8	905-MISC CUST ACCTS EXP	EXP905	155	9	0	46	12	14
9	906-CUSTOMER SERVICE & INFO	EXP906	0	0	0	0	0	0
10	907-SUPERV. CUSTOMER SERV.	LABCS	0	0	0	0	0	0
11	908-CUSTOMER ASSISTANCE	EXP908	5,291	11	9	8	1	499
12	909-INFO & INSTRUCTIONAL ADVERT.	EXP909	1,425	3	3	2	0	134
13	910-MISC. CUST. SERV. & INFO.	EXP910	0	0	0	0	0	0
14	TOTAL CUSTOMER ACCTS LABOR		137,397	361	241	359	12,302	834
15								
16	SALES LABOR							
17	912-DEMONSTRATING & SELLING	EXP912	0	0	0	0	0	0
18	913-ADVERTISING EXPENSES	EXP913	0	0	0	0	0	0
19	TOTAL SALES LABOR		0	0	0	0	0	0
20								
21	ADMINISTRATIVE & GENERAL LABOR							
22	920-ADMIN & GENERAL SALARY	EXP920	297,335	22,550	3,135	94,481	44,835	33,086
23	921-OFFICE SUPPLIES & EXP	EXP921	0	0	0	0	0	0
24	923-OUTSIDE SERV EMPLOYED	EXP923	0	0	0	0	0	0
25	924-PROPERTY INSURANCE	EXP924	0	0	0	0	0	0
26	925-INJURIES & DAMAGES	EXP925	2,441	185	26	776	368	272
27	926-EMPLOYED PENSION & BENF	EXP926	11,479	871	121	3,648	1,731	1,277
28	928-REGULATORY COMM EXPENSE	EXP928	0	0	0	0	0	0
29	930-MISCELLANEOUS GEN EXP	EXP930	3,449	262	36	1,096	520	384
30	931-RENTS	EXP931	0	0	0	0	0	0
31	932-MAINT OF GENERAL PLT	EXP932	1,370	104	14	435	207	152
32	TOTAL ADMIN & GEN LABOR		316,074	23,971	3,333	100,435	47,661	35,171
33								
34	**CAPITALIZED LABOR**							
35	371	CAPLABX	0	0	0	0	0	0
36	376-MAINS	PLT376	0	0	0	0	0	0
37	378-MEAS. & REG. EQUIP-GEN	PLT378	0	0	0	0	0	0
38	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	0	0	0	0	0	0
39	380-SERVICES	PLT380	0	0	0	0	0	0
40	382-METER INSTALLATIONS	PLT382	0	0	0	0	0	0
41	384-REGULATOR INSTALLATIONS	PLT384	0	0	0	0	0	0
42	385-INDUSTRIAL MEAS. EQUIP.	PLT385	0	0	0	0	0	0
43	387-OTHER EQUIPMENT	PLT387	0	0	0	0	0	0
44	390-STRUCTURES & IMPROVE.	PLT390	0	0	0	0	0	0
45	391-OFFICE FURN & EQUIP	PLT391	0	0	0	0	0	0
46	TOTAL CAPITALIZED LABOR		0	0	0	0	0	0
47								
48	SUM OF ALLOCATED LABOR EXP		1,085,887	82,355	11,450	345,050	163,741	120,831

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL RESIDENTIAL SERVICE (14)	RESIDENTIAL CARES (15)	COMMERCIAL SM. VOL. (16)	COMMERCIAL LG. VOL. (17)	COMMERCIAL TRANS-PORTATION (18)
1	DEVEL OF LABOR ALLOC CON'T.						
2	**EXPENSED LABOR CONTINUED**						
3	CUSTOMER ACCOUNT LABOR						
4	901-SUPERVISION	LABCA	30,046	1,702	2,738	3	4
5	902-METER READING EXPENSE	EXP902	584,950	33,128	53,295	66	103
6	903-CUST RECORDS & COLLECT	EXP903	817,618	46,305	74,493	92	72
7	904-UNCOLLECTIBLE ACCOUNTS	EXP904	0	0	0	0	0
8	905-MISC CUST ACCTS EXP	EXP905	1,523	86	155	1	7
9	906-CUSTOMER SERVICE & INFO	EXP906	0	0	0	0	0
10	907-SUPERV. CUSTOMER SERV.	LABCS	0	0	0	0	0
11	908-CUSTOMER ASSISTANCE	EXP908	58,075	3,289	5,291	7	4
12	909-INFO & INSTRUCTIONAL ADVERT.	EXP909	15,646	886	1,425	2	1
13	910-MISC. CUST. SERV. & INFO.	EXP910	0	0	0	0	0
14	TOTAL CUSTOMER ACCTS LABOR		1,507,857	85,396	137,397	170	192
15							
16	SALES LABOR						
17	912-DEMONSTRATING & SELLING	EXP912	0	0	0	0	0
18	913-ADVERTISING EXPENSES	EXP913	0	0	0	0	0
19	TOTAL SALES LABOR		0	0	0	0	0
20							
21	ADMINISTRATIVE & GENERAL LABOR						
22	920-ADMIN & GENERAL SALARY	EXP920	2,040,168	113,865	297,335	8,467	14,083
23	921-OFFICE SUPPLIES & EXP	EXP921	0	0	0	0	0
24	923-OUTSIDE SERV EMPLOYED	EXP923	0	0	0	0	0
25	924-PROPERTY INSURANCE	EXP924	0	0	0	0	0
26	925-INJURIES & DAMAGES	EXP925	16,746	935	2,441	70	116
27	926-EMPLOYED PENSION & BENF	EXP926	78,764	4,396	11,479	327	544
28	928-REGULATORY COMM EXPENSE	EXP928	0	0	0	0	0
29	930-MISCELLANEOUS GEN EXP	EXP930	23,666	1,321	3,449	98	163
30	931-RENTS	EXP931	0	0	0	0	0
31	932-MAINT OF GENERAL PLT	EXP932	9,398	525	1,370	39	65
32	TOTAL ADMIN & GEN LABOR		2,168,742	121,041	316,074	9,001	14,971
33							
34	**CAPITALIZED LABOR**						
35	371	CAPLABX	0	0	0	0	0
36	376-MAINS	PLT376	0	0	0	0	0
37	378-MEAS. & REG. EQUIP-GEN	PLT378	0	0	0	0	0
38	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	0	0	0	0	0
39	380-SERVICES	PLT380	0	0	0	0	0
40	382-METER INSTALLATIONS	PLT382	0	0	0	0	0
41	384-REGULATOR INSTALLATIONS	PLT384	0	0	0	0	0
42	385-INDUSTRIAL MEAS. EQUIP.	PLT385	0	0	0	0	0
43	387-OTHER EQUIPMENT	PLT387	0	0	0	0	0
44	390-STRUCTURES & IMPROVE.	PLT390	0	0	0	0	0
45	391-OFFICE FURN & EQUIP	PLT391	0	0	0	0	0
46	TOTAL CAPITALIZED LABOR		0	0	0	0	0
47							
48	*SUM OF ALLOCATED LABOR EXP*		7,450,818	415,841	1,085,887	30,923	51,432

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	DEVEL OF LABOR ALLOC CON'T.				
2	**EXPENSED LABOR CONTINUED**				
3	CUSTOMER ACCOUNT LABOR				
4	901-SUPERVISION	LABCA	5	1	6
5	902-METER READING EXPENSE	EXP902	94	23	140
6	903-CUST RECORDS & COLLECT	EXP903	131	33	98
7	904-UNCOLLECTIBLE ACCOUNTS	EXP904	0	0	0
8	905-MISC CUST ACCTS EXP	EXP905	0	0	46
9	906-CUSTOMER SERVICE & INFO	EXP906	0	0	0
10	907-SUPERV. CUSTOMER SERV.	LABCS	0	0	0
11	908-CUSTOMER ASSISTANCE	EXP908	9	2	6
12	909-INFO & INSTRUCTIONAL ADVERT.	EXP909	3	1	2
13	910-MISC. CUST. SERV. & INFO.	EXP910	0	0	0
14	TOTAL CUSTOMER ACCTS LABOR		241	60	298
15					
16	SALES LABOR				
17	912-DEMONSTRATING & SELLING	EXP912	0	0	0
18	913-ADVERTISING EXPENSES	EXP913	0	0	0
19	TOTAL SALES LABOR		0	0	0
20					
21	ADMINISTRATIVE & GENERAL LABOR				
22	920-ADMIN & GENERAL SALARY	EXP920	3,135	5,961	88,520
23	921-OFFICE SUPPLIES & EXP	EXP921	0	0	0
24	923-OUTSIDE SERV EMPLOYED	EXP923	0	0	0
25	924-PROPERTY INSURANCE	EXP924	0	0	0
26	925-INJURIES & DAMAGES	EXP925	26	49	727
27	926-EMPLOYED PENSION & BENF	EXP926	121	230	3,417
28	928-REGULATORY COMM EXPENSE	EXP928	0	0	0
29	930-MISCELLANEOUS GEN EXP	EXP930	36	69	1,027
30	931-RENTS	EXP931	0	0	0
31	932-MAINT OF GENERAL PLT	EXP932	14	27	408
32	TOTAL ADMIN & GEN LABOR		3,333	6,337	94,098
33					
34	**CAPITALIZED LABOR**				
35	371	CAPLABX	0	0	0
36	376-MAINS	PLT376	0	0	0
37	378-MEAS. & REG. EQUIP-GEN	PLT378	0	0	0
38	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	0	0	0
39	380-SERVICES	PLT380	0	0	0
40	382-METER INSTALLATIONS	PLT382	0	0	0
41	384-REGULATOR INSTALLATIONS	PLT384	0	0	0
42	385-INDUSTRIAL MEAS. EQUIP.	PLT385	0	0	0
43	387-OTHER EQUIPMENT	PLT387	0	0	0
44	390-STRUCTURES & IMPROVE.	PLT390	0	0	0
45	391-OFFICE FURN & EQUIP	PLT391	0	0	0
46	TOTAL CAPITALIZED LABOR		0	0	0
47					
48	SUM OF ALLOCATED LABOR EXP		11,450	21,771	323,279

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	LG. VOL. (23)	TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	DEVEL OF LABOR ALLOC CON'T.						
2	**EXPENSED LABOR CONTINUED**						
3	CUSTOMER ACCOUNT LABOR						
4	901-SUPERVISION	LABCA	258	1	3	0	1
5	902-METER READING EXPENSE	EXP902	5,017	23	75	0	23
6	903-CUST RECORDS & COLLECT	EXP903	7,013	33	52	0	33
7	904-UNCOLLECTIBLE ACCOUNTS	EXP904	0	0	0	0	0
8	905-MISC CUST ACCTS EXP	EXP905	12	0	14	0	0
9	906-CUSTOMER SERVICE & INFO	EXP906	0	0	0	0	0
10	907-SUPERV. CUSTOMER SERV.	LABCS	0	0	0	0	0
11	908-CUSTOMER ASSISTANCE	EXP908	1	0	498	2	4
12	909-INFO & INSTRUCTIONAL ADVERT.	EXP909	0	0	134	1	1
13	910-MISC. CUST. SERV. & INFO.	EXP910	0	0	0	0	0
14	TOTAL CUSTOMER ACCTS LABOR		12,302	58	776	3	62
15							
16	SALES LABOR						
17	912-DEMONSTRATING & SELLING	EXP912	0	0	0	0	0
18	913-ADVERTISING EXPENSES	EXP913	0	0	0	0	0
19	TOTAL SALES LABOR		0	0	0	0	0
20							
21	ADMINISTRATIVE & GENERAL LABOR						
22	920-ADMIN & GENERAL SALARY	EXP920	44,835	6,220	26,866	608	383
23	921-OFFICE SUPPLIES & EXP	EXP921	0	0	0	0	0
24	923-OUTSIDE SERV EMPLOYED	EXP923	0	0	0	0	0
25	924-PROPERTY INSURANCE	EXP924	0	0	0	0	0
26	925-INJURIES & DAMAGES	EXP925	368	51	221	5	3
27	926-EMPLOYED PENSION & BENF	EXP926	1,731	240	1,037	23	15
28	928-REGULATORY COMM EXPENSE	EXP928	0	0	0	0	0
29	930-MISCELLANEOUS GEN EXP	EXP930	520	72	312	7	4
30	931-RENTS	EXP931	0	0	0	0	0
31	932-MAINT OF GENERAL PLT	EXP932	207	29	124	3	2
32	TOTAL ADMIN & GEN LABOR		47,661	6,612	28,559	646	407
33							
34	**CAPITALIZED LABOR**						
35	371	CAPLABX	0	0	0	0	0
36	376-MAINS	PLT376	0	0	0	0	0
37	378-MEAS. & REG. EQUIP-GEN	PLT378	0	0	0	0	0
38	379-MEAS. & REG. EQUIP-CITY GATE	PLT379	0	0	0	0	0
39	380-SERVICES	PLT380	0	0	0	0	0
40	382-METER INSTALLATIONS	PLT382	0	0	0	0	0
41	384-REGULATOR INSTALLATIONS	PLT384	0	0	0	0	0
42	385-INDUSTRIAL MEAS. EQUIP.	PLT385	0	0	0	0	0
43	387-OTHER EQUIPMENT	PLT387	0	0	0	0	0
44	390-STRUCTURES & IMPROVE.	PLT390	0	0	0	0	0
45	391-OFFICE FURN & EQUIP	PLT391	0	0	0	0	0
46	TOTAL CAPITALIZED LABOR		0	0	0	0	0
47							
48	SUM OF ALLOCATED LABOR EXP		163,741	22,716	98,115	2,219	1,399

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	ALLOCATION FACTOR TABLE								
2	DEMAND RELATED								
3									
4	*PRODUCTION ALLOCATORS*								
5	ANNUAL FIRM THERM THROUGHPUT	DEMGAS	116,905,397	71,600,398	30,629,902	1,766,419	6,318,718	1,192,130	5,397,831
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22	TRANSMISSION ALLOCATORS								
23									
24	PROPORTIONAL RESPONSIBILITY	TRANS	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
25									
26									
27									
28									
29									
30									
31	DISTRIBUTION ALLOCATORS								
32									
33	PROPORTIONAL RESPONSIBILITY	DISTR	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
34	DISTRIBUTION MAINS	DISTMAIN	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
35	DISTRIBUTION REGULATORS	DISTREG	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
36									
37									
38									
39									
40									
41									
42									
43	PROPORTIONAL RESPONSIBILITY		1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
44									
45									

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			COMMERCIAL		INDUSTRIAL		PUBLIC AUTHORITY	
		ALLOC	SM. VOL. (8)	LG. VOL. (9)	SM. VOL. (10)	LG. VOL. (11)	SM. VOL. (12)	LG. VOL. (13)
1	ALLOCATION FACTOR TABLE							
2	DEMAND RELATED							
3								
4	PRODUCTION ALLOCATORS							
5	ANNUAL FIRM THERM THROUGHPUT	DEMGAS	29,291,657	1,338,244	553,766	1,212,653	5,167,584	1,151,133
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22	TRANSMISSION ALLOCATORS							
23								
24	PROPORTIONAL RESPONSIBILITY	TRANS	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
25								
26								
27								
28								
29								
30								
31	DISTRIBUTION ALLOCATORS							
32								
33	PROPORTIONAL RESPONSIBILITY	DISTR	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
34	DISTRIBUTION MAINS	DISTMAIN	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
35	DISTRIBUTION REGULATORS	DISTREG	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
36								
37								
38								
39								
40								
41								
42								
43	PROPORTIONAL RESPONSIBILITY		0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
44								
45								

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			RESIDENTIAL		COMMERCIAL		
		ALLOC	RESIDENTIAL SERVICE (14)	CARES (15)	SM. VOL. (16)	LG. VOL. (17)	TRANS-PORTATION (18)
1	ALLOCATION FACTOR TABLE						
2	DEMAND RELATED						
3							
4	PRODUCTION ALLOCATORS						
5	ANNUAL FIRM THERM THROUGHPUT	DEMGAS	68,066,962	3,533,436	29,291,657	1,338,244	0
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22	TRANSMISSION ALLOCATORS						
23							
24	PROPORTIONAL RESPONSIBILITY	TRANS	0.51937	0.02705	0.20415	0.00910	0.01765
25							
26							
27							
28							
29							
30							
31	DISTRIBUTION ALLOCATORS						
32							
33	PROPORTIONAL RESPONSIBILITY	DISTR	0.51937	0.02705	0.20415	0.00910	0.01765
34	DISTRIBUTION MAINS	DISTMAIN	0.51937	0.02705	0.20415	0.00910	0.01765
35	DISTRIBUTION REGULATORS	DISTREG	0.51937	0.02705	0.20415	0.00910	0.01765
36							
37							
38							
39							
40							
41							
42							
43	PROPORTIONAL RESPONSIBILITY		0.51937	0.02705	0.20415	0.00910	0.01765
44							
45							

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			INDUSTRIAL		
		ALLOC	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(19)	(20)	(21)
1	ALLOCATION FACTOR TABLE				
2	DEMAND RELATED				
3					
4	PRODUCTION ALLOCATORS				
5	ANNUAL FIRM THERM THROUGHPUT	DEMGAS	553,766	1,212,653	0
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22	TRANSMISSION ALLOCATORS				
23					
24	PROPORTIONAL RESPONSIBILITY	TRANS	0.00405	0.00738	0.12158
25					
26					
27					
28					
29					
30					
31	DISTRIBUTION ALLOCATORS				
32					
33	PROPORTIONAL RESPONSIBILITY	DISTR	0.00405	0.00738	0.12158
34	DISTRIBUTION MAINS	DISTMAIN	0.00405	0.00738	0.12158
35	DISTRIBUTION REGULATORS	DISTREG	0.00405	0.00738	0.12158
36					
37					
38					
39					
40					
41					
42					
43	PROPORTIONAL RESPONSIBILITY		0.00405	0.00738	0.12158
44					
45					

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			PUBLIC AUTHORITY				
		ALLOC	SM. VOL. (22)	LG. VOL. (23)	TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	ALLOCATION FACTOR TABLE						
2	DEMAND RELATED						
3							
4	PRODUCTION ALLOCATORS						
5	ANNUAL FIRM THERM THROUGHPUT	DEMGAS	5,167,584	1,151,133	0	1,192,130	5,397,831
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22	TRANSMISSION ALLOCATORS						
23							
24	PROPORTIONAL RESPONSIBILITY	TRANS	0.04382	0.00866	0.03588	0.00085	0.00045
25							
26							
27							
28							
29							
30							
31	DISTRIBUTION ALLOCATORS						
32							
33	PROPORTIONAL RESPONSIBILITY	DISTR	0.04382	0.00866	0.03588	0.00085	0.00045
34	DISTRIBUTION MAINS	DISTMAIN	0.04382	0.00866	0.03588	0.00085	0.00045
35	DISTRIBUTION REGULATORS	DISTREG	0.04382	0.00866	0.03588	0.00085	0.00045
36							
37							
38							
39							
40							
41							
42							
43	PROPORTIONAL RESPONSIBILITY		0.04382	0.00866	0.03588	0.00085	0.00045
44							
45							

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	ALLOCATION FACTOR TABLE CONT								
2	COMMODITY RELATED								
3									
4	ANNUAL FIRM THERM THROUGHPUT	GASSALES	116,905,397	71,600,398	30,629,902	1,766,419	6,318,718	1,192,130	5,397,831
5									
6									
7	ANNUAL FIRM THERM THROUGHPUT	THERMS	137,141,116	71,600,398	33,670,786	13,348,945	11,931,026	1,192,130	5,397,831
8	CARES	CARES	133,607,680	68,066,962	33,670,786	13,348,945	11,931,026	1,192,130	5,397,831
9									
10									
11									
12									
13									
14									
15									
16	CUSTOMER RELATED								
17									
18	YEAR END NUMBER OF CUSTOMERS	CUST10	144,571	132,036	11,408	38	1,076	5	8
19	ACCT 380-SERVICES	CUST380	79,807,979	72,894,669	6,299,858	16,193	594,499	0	2,760
20	ACCT 381-METERS	CUST381	18,667,343	16,912,683	1,531,528	61,130	161,360	0	640
21	ACCT 382-METER INSTALLATIONS	CUST382	10,371,907	9,396,987	850,944	33,965	89,655	0	356
22	ACCT 383-HOUSE REGULATORS	CUST383	2,685,089	2,471,943	213,146	0	0	0	0
23	ACCT 384-HOUSE REG. INSTALLATION	CUST384	93,643	86,209	7,433	0	0	0	0
24	ACCT 385-INDUSTRIAL REG EQUIP	CUST385	1,313,325	0	420,938	673,500	218,888	0	0
25	CUSTOMER DEPOSITS	CUSTDEP	2,609,271	2,018,074	591,197	0	0	0	0
26									
27									
28	ACCT 487-MISC. SERVICE REVENUE	CUST487B	1,211,079	1,157,058	52,906	162	953	0	0
29									
30	ACCT 902-METER READ EXP	CUST902	983,242	897,750	77,654	374	7,430	0	34
31	ACCT 903-CUST RECORDS & COLL	CUST903	3,972,422	3,627,873	313,505	1,099	29,807	0	137
32	ACCT 912-DEMO & SELLING	CDA912	3,970,279	3,627,873	312,818	0	29,587	0	0
33	ACCT 913-ADVERTISING EXPENSES	CDA913	3,970,279	3,627,873	312,818	0	29,587	0	0
34									
35									
36									
37									
38									
39									
40									
41									
42									
43									
44									
45									

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	ALLOCATION FACTOR TABLE CONT							
2	COMMODITY RELATED							
3	---							
4	ANNUAL FIRM THERM THROUGHPUT	GASSALES	29,291,657	1,338,244	553,766	1,212,653	5,167,584	1,151,133
5								
6								
7	ANNUAL FIRM THERM THROUGHPUT	THERMS	29,291,657	4,379,129	553,766	12,795,179	5,167,584	6,763,442
8	CARES	CARES	29,291,657	4,379,129	553,766	12,795,179	5,167,584	6,763,442
9								
10								
11								
12								
13								
14								
15								
16	CUSTOMER RELATED							
17	---							
18	YEAR END NUMBER OF CUSTOMERS	CUST10	11,385	23	20	18	3	1,073
19	ACCT 380-SERVICES	CUST380	6,285,435	14,423	11,042	5,151	591,738	2,760
20	ACCT 381-METERS	CUST381	1,458,318	73,211	2,562	58,569	137,292	24,068
21	ACCT 382-METER INSTALLATIONS	CUST382	810,267	40,677	1,423	32,542	76,282	13,373
22	ACCT 383-HOUSE REGULATORS	CUST383	213,146	0	0	0	0	0
23	ACCT 384-HOUSE REG. INSTALLATION	CUST384	7,433	0	0	0	0	0
24	ACCT 385-INDUSTRIAL REG EQUIP	CUST385	0	420,938	336,750	336,750	0	218,888
25	CUSTOMER DEPOSITS	CUSTDEP	590,470	726	0	0	0	0
26								
27								
28	ACCT 487-MISC. SERVICE REVENUE	CUST487B	52,906	0	162	0	953	0
29								
30	ACCT 902-METER READ EXP	CUST902	77,410	245	136	238	7,288	143
31	ACCT 903-CUST RECORDS & COLL	CUST903	312,818	687	550	550	29,450	357
32	ACCT 912-DEMO & SELLING	CDA912	312,818	0	0	0	29,450	137
33	ACCT 913-ADVERTISING EXPENSES	CDA913	312,818	0	0	0	29,450	137
34								
35								
36								
37								
38								
39								
40								
41								
42								
43								
44								
45								

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	ALLOCATION FACTOR TABLE CONT						
2	COMMODITY RELATED						
3	----------						
4	ANNUAL FIRM THERM THROUGHPUT	GASSALES	68,066,962	3,533,436	29,291,657	1,338,244	0
5							
6							
7	ANNUAL FIRM THERM THROUGHPUT	THERMS	68,066,962	3,533,436	29,291,657	1,338,244	3,040,885
8	CARES	CARES	68,066,962	0	29,291,657	1,338,244	3,040,885
9							
10							
11							
12							
13							
14							
15							
16	CUSTOMER RELATED						
17	----------						
18	YEAR END NUMBER OF CUSTOMERS	CUST10	124,959	7,077	11,385	14	9
19	ACCT 380-SERVICES	CUST380	68,987,596	3,907,073	6,285,435	14,423	0
20	ACCT 381-METERS	CUST381	16,006,182	906,501	1,458,318	40,998	32,213
21	ACCT 382-METER INSTALLATIONS	CUST382	8,893,319	503,668	810,267	22,779	17,898
22	ACCT 383-HOUSE REGULATORS	CUST383	2,339,450	132,493	213,146	0	0
23	ACCT 384-HOUSE REG. INSTALLATION	CUST384	81,588	4,621	7,433	0	0
24	ACCT 385-INDUSTRIAL REG EQUIP	CUST385	0	0	0	235,725	185,213
25	CUSTOMER DEPOSITS	CUSTDEP	1,909,908	108,167	590,470	726	0
26							
27							
28	ACCT 487-MISC. SERVICE REVENUE	CUST487B	1,095,040	62,018	52,906	0	0
29							
30	ACCT 902-METER READ EXP	CUST902	849,631	48,118	77,410	95	150
31	ACCT 903-CUST RECORDS & COLL	CUST903	3,433,423	194,450	312,818	385	302
32	ACCT 912-DEMO & SELLING	CDA912	3,433,423	194,450	312,818	0	0
33	ACCT 913-ADVERTISING EXPENSES	CDA913	3,433,423	194,450	312,818	0	0
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	ALLOCATION FACTOR TABLE CONT				
2	COMMODITY RELATED				
3					
4	ANNUAL FIRM THERM THROUGHPUT	GASSALES	553,766	1,212,653	0
5					
6					
7	ANNUAL FIRM THERM THROUGHPUT	THERMS	553,766	1,212,653	11,582,526
8	CARES	CARES	553,766	1,212,653	11,582,526
9					
10					
11					
12					
13					
14					
15					
16	CUSTOMER RELATED				
17					
18	YEAR END NUMBER OF CUSTOMERS	CUST10	20	5	13
19	ACCT 380-SERVICES	CUST380	11,042	5,151	0
20	ACCT 381-METERS	CUST381	2,562	14,642	43,926
21	ACCT 382-METER INSTALLATIONS	CUST382	1,423	8,135	24,406
22	ACCT 383-HOUSE REGULATORS	CUST383	0	0	0
23	ACCT 384-HOUSE REG. INSTALLATION	CUST384	0	0	0
24	ACCT 385-INDUSTRIAL REG EQUIP	CUST385	336,750	84,188	252,563
25	CUSTOMER DEPOSITS	CUSTDEP	0	0	0
26					
27					
28	ACCT 487-MISC. SERVICE REVENUE	CUST487B	162	0	0
29					
30	ACCT 902-METER READ EXP	CUST902	136	34	204
31	ACCT 903-CUST RECORDS & COLL	CUST903	550	137	412
32	ACCT 912-DEMO & SELLING	CDA912	0	0	0
33	ACCT 913-ADVERTISING EXPENSES	CDA913	0	0	0
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	ALLOCATION FACTOR TABLE CONT						
2	COMMODITY RELATED						
3							
4	ANNUAL FIRM THERM THROUGHPUT	GASSALES	5,167,584	1,151,133	0	1,192,130	5,397,831
5							
6							
7	ANNUAL FIRM THERM THROUGHPUT	THERMS	5,167,584	1,151,133	5,612,308	1,192,130	5,397,831
8	CARES	CARES	5,167,584	1,151,133	5,612,308	1,192,130	5,397,831
9							
10							
11							
12							
13							
14							
15							
16	CUSTOMER RELATED						
17							
18	YEAR END NUMBER OF CUSTOMERS	CUST10	3	1	1,072	5	8
19	ACCT 380-SERVICES	CUST380	591,738	2,760	0	0	2,760
20	ACCT 381-METERS	CUST381	137,292	640	23,427	0	640
21	ACCT 382-METER INSTALLATIONS	CUST382	76,282	356	13,017	0	356
22	ACCT 383-HOUSE REGULATORS	CUST383	0	0	0	0	0
23	ACCT 384-HOUSE REG. INSTALLATION	CUST384	0	0	0	0	0
24	ACCT 385-INDUSTRIAL REG EQUIP	CUST385	0	84,188	134,700	0	0
25	CUSTOMER DEPOSITS	CUSTDEP	0	0	0	0	0
26							
27							
28	ACCT 487-MISC. SERVICE REVENUE	CUST487B	953	0	0	0	0
29							
30	ACCT 902-METER READ EXP	CUST902	7,288	34	109	0	34
31	ACCT 903-CUST RECORDS & COLL	CUST903	29,450	137	220	0	137
32	ACCT 912-DEMO & SELLING	CDA912	29,450	137	0	0	0
33	ACCT 913-ADVERTISING EXPENSES	CDA913	29,450	137	0	0	0
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	INTERNALLY DEVELOPED FACTORS								
2	----------								
3	TOTAL GAS PLANT IN SERVICE	PLANT	287,517,886	200,012,920	48,453,782	22,977,931	15,852,403	142,389	78,461
4	SUM OF ALLOCATED LABOR EXP	LABOR	9,679,590	7,866,658	1,168,242	356,499	284,573	2,219	1,399
5	ACCT 302-FRANCHISE & CONSENTS	PLT302	326,528	265,371	39,409	12,026	9,600	75	47
6	ACCT 303-MISC. INTANGIBLE PLANT	PLT303	741,358	602,506	89,475	27,304	21,795	170	107
7	ACCT 365-LAND & LAND RIGHTS	PLT365	70,648	38,603	16,312	9,397	6,243	60	32
8	ACCT 366-STRUCTURES & IMPROV.	PLT366	13,440	7,344	3,103	1,788	1,188	11	6
9	ACCT 367-MAINS	PLT367	15,882,233	8,678,387	3,667,179	2,112,550	1,403,471	13,555	7,091
10	ACCT 369-MEAS. & REG STATION EQ	PLT369	367,621	200,876	84,883	48,899	32,486	314	164
11	ACCT 371-OTHER TRANS EQUIP	PLT371	(24,187)	(13,216)	(5,585)	(3,217)	(2,137)	(21)	(11)
12	TOTAL TRANSMISSION PLANT	TRANPLT	16,309,754	8,911,994	3,765,893	2,169,416	1,441,250	13,920	7,282
13	ACCT 374-DISTR LAND & LAND RIGHTS	PLT374	202,970	110,907	46,865	26,998	17,936	173	91
14	ACCT 375-STRUCTURES & IMPROV	PLT375	10,011	5,470	2,312	1,332	885	9	4
15	ACCT 376-MAINS	PLT376	139,505,789	76,228,907	32,211,637	18,556,137	12,327,758	119,063	62,288
16	ACCT 378-MEAS & REG EQ - GEN	PLT378	2,155,579	1,177,854	497,719	286,721	190,483	1,840	962
17	ACCT 379-MEAS & REG EQ - CITY GATE	PLT379	2,197,502	1,200,761	507,399	292,297	194,187	1,875	981
18	ACCT 380-SERVICES	PLT380	79,807,979	72,894,669	6,299,858	16,193	594,499	0	2,760
19	ACCT 381-METERS	PLT381	12,619,237	11,433,076	1,035,322	41,325	109,081	0	433
20	ACCT 382-METER INSTALLATIONS	PLT382	7,888,695	7,147,187	647,214	25,833	68,190	0	271
21	ACCT 383-REGULATORS	PLT383	2,708,048	2,493,079	214,969	0	0	0	0
22	ACCT 384-REGULATOR INSTALLATIONS	PLT384	1,270,396	1,169,550	100,846	0	0	0	0
23	ACCT 385-INDUSTRIAL MEAS. EQUIP	PLT385	1,326,862	0	425,276	680,442	221,144	0	0
24	ACCT 387-OTHER EQUIPMENT	PLT387	923,636	504,694	213,266	122,856	81,619	788	412
25	ACCT 389-GEN PLT LAND	PLT389	344,920	280,319	41,629	12,703	10,140	79	50
26	ACCT 390-STRUCTURES & IMPROVE	PLT390	5,222,334	4,244,220	630,290	192,339	153,533	1,197	755
27	ACCT 391-OFFICE FURN & EQUIP	PLT391	1,459,028	1,185,761	176,092	53,736	42,894	335	211
28	ACCT 392-TRANSPORTATION EQUIP	PLT392	7,095,654	5,766,679	856,384	261,333	208,607	1,627	1,025
29	ACCT 393-STORES EQUIPMENT	PLT393	183,221	148,905	22,113	6,748	5,387	42	26
30	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	2,040,787	1,658,559	246,305	75,162	59,998	468	295
31	ACCT 395-LABORATORY EQUIPMENT	PLT395	707,953	575,358	85,444	26,074	20,813	162	102
32	ACCT 396-POWER OPER EQUIP	PLT396	1,273,566	1,035,034	153,708	46,905	37,442	292	184
33	ACCT 397-COMMUNICATION EQUIP	PLT397	948,123	770,545	114,430	34,919	27,874	217	137
34	ACCT 398-MISCELLANEOUS EQUIP	PLT398	247,956	201,515	29,926	9,132	7,290	57	36
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	0	0	0	0	0	0	0
36	ACCT 367 & 376 TOTAL MAINS	PLT367376	155,388,022	84,907,294	35,878,816	20,668,687	13,731,229	132,618	69,379
37	ACCT 376 MAINS + 380 SERVICES	PLT376380	219,313,768	149,123,576	38,511,495	18,572,330	12,922,257	119,063	65,048
38	TOTAL DISTRIBUTION PLANT	DISTRPLT	250,616,704	174,366,155	42,202,683	20,050,133	13,805,781	123,748	68,203
39									
40	ACCT 378 & 379 MEAS. & REG. EQUIP	PLT37879	4,353,081	2,378,615	1,005,119	579,018	384,670	3,715	1,944
41	ACCT 382 & 384 INSTALLATIONS	PLT38284	9,159,090	8,316,737	748,060	25,833	68,190	0	271
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	INTERNALLY DEVELOPED FACTORS							
2	----------							
3	TOTAL GAS PLANT IN SERVICE	PLANT	43,443,335	5,010,447	1,031,030	21,946,902	8,159,970	7,692,433
4	SUM OF ALLOCATED LABOR EXP	LABOR	1,085,887	82,355	11,450	345,050	163,741	120,831
5	ACCT 302-FRANCHISE & CONSENTS	PLT302	36,631	2,778	386	11,640	5,524	4,076
6	ACCT 303-MISC. INTANGIBLE PLANT	PLT303	83,168	6,308	877	26,427	12,541	9,254
7	ACCT 365-LAND & LAND RIGHTS	PLT365	14,422	1,890	286	9,111	3,096	3,147
8	ACCT 366-STRUCTURES & IMPROV.	PLT366	2,744	360	54	1,733	589	599
9	ACCT 367-MAINS	PLT367	3,242,309	424,870	64,255	2,048,295	696,026	707,445
10	ACCT 369-MEAS. & REG STATION EQ	PLT369	75,049	9,834	1,487	47,411	16,111	16,375
11	ACCT 371-OTHER TRANS EQUIP	PLT371	(4,938)	(647)	(98)	(3,119)	(1,060)	(1,077)
12	TOTAL TRANSMISSION PLANT	TRANPLT	3,329,586	436,307	65,985	2,103,431	714,762	726,488
13	ACCT 374-DISTR LAND & LAND RIGHTS	PLT374	41,436	5,430	821	26,177	8,895	9,041
14	ACCT 375-STRUCTURES & IMPROV	PLT375	2,044	268	41	1,291	439	446
15	ACCT 376-MAINS	PLT376	28,479,676	3,731,960	564,401	17,991,736	6,113,731	6,214,027
16	ACCT 378-MEAS & REG EQ - GEN	PLT378	440,055	57,665	8,721	278,000	94,467	96,016
17	ACCT 379-MEAS & REG EQ - CITY GATE	PLT379	448,613	58,786	8,890	283,407	96,304	97,884
18	ACCT 380-SERVICES	PLT380	6,285,435	14,423	11,042	5,151	591,738	2,760
19	ACCT 381-METERS	PLT381	985,831	49,491	1,732	39,593	92,810	16,270
20	ACCT 382-METER INSTALLATIONS	PLT382	616,275	30,938	1,083	24,751	58,019	10,171
21	ACCT 383-REGULATORS	PLT383	214,969	0	0	0	0	0
22	ACCT 384-REGULATOR INSTALLATIONS	PLT384	100,846	0	0	0	0	0
23	ACCT 385-INDUSTRIAL MEAS. EQUIP	PLT385	0	425,276	340,221	340,221	0	221,144
24	ACCT 387-OTHER EQUIPMENT	PLT387	188,557	24,708	3,737	119,119	40,478	41,142
25	ACCT 389-GEN PLT LAND	PLT389	38,694	2,935	408	12,295	5,835	4,306
26	ACCT 390-STRUCTURES & IMPROVE	PLT390	585,858	44,432	6,177	186,161	88,342	65,191
27	ACCT 391-OFFICE FURN & EQUIP	PLT391	163,678	12,414	1,726	52,010	24,681	18,213
28	ACCT 392-TRANSPORTATION EQUIP	PLT392	796,013	60,371	8,393	252,940	120,031	88,576
29	ACCT 393-STORES EQUIPMENT	PLT393	20,554	1,559	217	6,531	3,099	2,287
30	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	228,942	17,363	2,414	72,748	34,522	25,475
31	ACCT 395-LABORATORY EQUIPMENT	PLT395	79,420	6,023	837	25,236	11,976	8,837
32	ACCT 396-POWER OPER EQUIP	PLT396	142,873	10,836	1,506	45,399	21,544	15,898
33	ACCT 397-COMMUNICATION EQUIP	PLT397	106,363	8,067	1,122	33,798	16,039	11,836
34	ACCT 398-MISCELLANEOUS EQUIP	PLT398	27,816	2,110	293	8,839	4,194	3,095
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	0	0	0	0	0	0
36	ACCT 367 & 376 TOTAL MAINS	PLT367376	31,721,985	4,156,830	628,656	20,040,031	6,809,758	6,921,472
37	ACCT 376 MAINS + 380 SERVICES	PLT376380	34,765,112	3,746,383	575,443	17,996,887	6,705,469	6,216,787
38	TOTAL DISTRIBUTION PLANT	DISTRPLT	37,803,738	4,398,945	940,688	19,109,445	7,096,880	6,708,900
39								
40	ACCT 378 & 379 MEAS. & REG. EQUIP	PLT37879	888,668	116,451	17,611	561,407	190,770	193,900
41	ACCT 382 & 384 INSTALLATIONS	PLT38284	717,121	30,938	1,083	24,751	58,019	10,171
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			RESIDENTIAL		COMMERCIAL		
		ALLOC	RESIDENTIAL SERVICE (14)	CARES (15)	SM. VOL. (16)	LG. VOL. (17)	TRANS-PORTATION (18)
1	INTERNALLY DEVELOPED FACTORS						
2							
3	TOTAL GAS PLANT IN SERVICE	PLANT	189,665,466	10,347,454	43,443,335	1,831,735	3,178,712
4	SUM OF ALLOCATED LABOR EXP	LABOR	7,450,818	415,841	1,085,887	30,923	51,432
5	ACCT 302-FRANCHISE & CONSENTS	PLT302	251,343	14,028	36,631	1,043	1,735
6	ACCT 303-MISC. INTANGIBLE PLANT	PLT303	570,657	31,849	83,168	2,368	3,939
7	ACCT 365-LAND & LAND RIGHTS	PLT365	36,692	1,911	14,422	643	1,247
8	ACCT 366-STRUCTURES & IMPROV.	PLT366	6,980	364	2,744	122	237
9	ACCT 367-MAINS	PLT367	8,248,747	429,640	3,242,309	144,573	280,297
10	ACCT 369-MEAS. & REG STATION EQ	PLT369	190,931	9,945	75,049	3,346	6,488
11	ACCT 371-OTHER TRANS EQUIP	PLT371	(12,562)	(654)	(4,938)	(220)	(427)
12	TOTAL TRANSMISSION PLANT	TRANPLT	8,470,789	441,205	3,329,586	148,465	287,842
13	ACCT 374-DISTR LAND & LAND RIGHTS	PLT374	105,416	5,491	41,436	1,848	3,582
14	ACCT 375-STRUCTURES & IMPROV	PLT375	5,200	271	2,044	91	177
15	ACCT 376-MAINS	PLT376	72,455,050	3,773,858	28,479,676	1,269,897	2,462,063
16	ACCT 378-MEAS & REG EQ - GEN	PLT378	1,119,542	58,312	440,055	19,622	38,043
17	ACCT 379-MEAS & REG EQ - CITY GATE	PLT379	1,141,315	59,446	448,613	20,003	38,783
18	ACCT 380-SERVICES	PLT380	68,987,596	3,907,073	6,285,435	14,423	0
19	ACCT 381-METERS	PLT381	10,820,276	612,800	985,831	27,715	21,776
20	ACCT 382-METER INSTALLATIONS	PLT382	6,764,106	383,081	616,275	17,326	13,613
21	ACCT 383-REGULATORS	PLT383	2,359,453	133,626	214,969	0	0
22	ACCT 384-REGULATOR INSTALLATIONS	PLT384	1,106,863	62,687	100,846	0	0
23	ACCT 385-INDUSTRIAL MEAS. EQUIP	PLT385	0	0	0	238,155	187,122
24	ACCT 387-OTHER EQUIPMENT	PLT387	479,708	24,986	188,557	8,408	16,301
25	ACCT 389-GEN PLT LAND	PLT389	265,501	14,818	38,694	1,102	1,833
26	ACCT 390-STRUCTURES & IMPROVE	PLT390	4,019,866	224,354	585,858	16,684	27,749
27	ACCT 391-OFFICE FURN & EQUIP	PLT391	1,123,080	62,681	163,678	4,661	7,752
28	ACCT 392-TRANSPORTATION EQUIP	PLT392	5,461,845	304,833	796,013	22,668	37,702
29	ACCT 393-STORES EQUIPMENT	PLT393	141,034	7,871	20,554	585	974
30	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	1,570,886	87,673	228,942	6,520	10,844
31	ACCT 395-LABORATORY EQUIPMENT	PLT395	544,944	30,414	79,420	2,262	3,762
32	ACCT 396-POWER OPER EQUIP	PLT396	980,321	54,713	142,873	4,069	6,767
33	ACCT 397-COMMUNICATION EQUIP	PLT397	729,813	40,732	106,363	3,029	5,038
34	ACCT 398-MISCELLANEOUS EQUIP	PLT398	190,863	10,652	27,816	792	1,318
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	0	0	0	0	0
36	ACCT 367 & 376 TOTAL MAINS	PLT367376	80,703,797	4,203,498	31,721,985	1,414,471	2,742,360
37	ACCT 376 MAINS + 380 SERVICES	PLT376380	141,442,646	7,680,930	34,765,112	1,284,320	2,462,063
38	TOTAL DISTRIBUTION PLANT	DISTRPLT	165,344,526	9,021,630	37,803,738	1,617,488	2,781,458
39							
40	ACCT 378 & 379 MEAS. & REG. EQUIP	PLT37879	2,260,857	117,758	888,668	39,625	76,825
41	ACCT 382 & 384 INSTALLATIONS	PLT38284	7,870,969	445,768	717,121	17,326	13,613
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	INTERNALLY DEVELOPED FACTORS				
2	----------				
3	TOTAL GAS PLANT IN SERVICE	PLANT	1,031,030	1,343,714	20,603,188
4	SUM OF ALLOCATED LABOR EXP	LABOR	11,450	21,771	323,279
5	ACCT 302-FRANCHISE & CONSENTS	PLT302	386	734	10,905
6	ACCT 303-MISC. INTANGIBLE PLANT	PLT303	877	1,667	24,760
7	ACCT 365-LAND & LAND RIGHTS	PLT365	286	522	8,590
8	ACCT 366-STRUCTURES & IMPROV.	PLT366	54	99	1,634
9	ACCT 367-MAINS	PLT367	64,255	117,277	1,931,017
10	ACCT 369-MEAS. & REG STATION EQ	PLT369	1,487	2,715	44,697
11	ACCT 371-OTHER TRANS EQUIP	PLT371	(98)	(179)	(2,941)
12	TOTAL TRANSMISSION PLANT	TRANPLT	65,985	120,434	1,982,997
13	ACCT 374-DISTR LAND & LAND RIGHTS	PLT374	821	1,499	24,678
14	ACCT 375-STRUCTURES & IMPROV	PLT375	41	74	1,217
15	ACCT 376-MAINS	PLT376	564,401	1,030,138	16,961,598
16	ACCT 378-MEAS & REG EQ - GEN	PLT378	8,721	15,917	262,083
17	ACCT 379-MEAS & REG EQ - CITY GATE	PLT379	8,890	16,227	267,180
18	ACCT 380-SERVICES	PLT380	11,042	5,151	0
19	ACCT 381-METERS	PLT381	1,732	9,898	29,695
20	ACCT 382-METER INSTALLATIONS	PLT382	1,083	6,188	18,563
21	ACCT 383-REGULATORS	PLT383	0	0	0
22	ACCT 384-REGULATOR INSTALLATIONS	PLT384	0	0	0
23	ACCT 385-INDUSTRIAL MEAS. EQUIP	PLT385	340,221	85,055	255,166
24	ACCT 387-OTHER EQUIPMENT	PLT387	3,737	6,820	112,299
25	ACCT 389-GEN PLT LAND	PLT389	408	776	11,520
26	ACCT 390-STRUCTURES & IMPROVE	PLT390	6,177	11,746	174,415
27	ACCT 391-OFFICE FURN & EQUIP	PLT391	1,726	3,282	48,729
28	ACCT 392-TRANSPORTATION EQUIP	PLT392	8,393	15,959	236,981
29	ACCT 393-STORES EQUIPMENT	PLT393	217	412	6,119
30	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	2,414	4,590	68,158
31	ACCT 395-LABORATORY EQUIPMENT	PLT395	837	1,592	23,644
32	ACCT 396-POWER OPER EQUIP	PLT396	1,506	2,864	42,535
33	ACCT 397-COMMUNICATION EQUIP	PLT397	1,122	2,132	31,665
34	ACCT 398-MISCELLANEOUS EQUIP	PLT398	293	558	8,281
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	0	0	0
36	ACCT 367 & 376 TOTAL MAINS	PLT367376	628,656	1,147,415	18,892,616
37	ACCT 376 MAINS + 380 SERVICES	PLT376380	575,443	1,035,289	16,961,598
38	TOTAL DISTRIBUTION PLANT	DISTRPLT	940,688	1,176,967	17,932,479
39					
40	ACCT 378 & 379 MEAS. & REG. EQUIP	PLT37879	17,611	32,144	529,263
41	ACCT 382 & 384 INSTALLATIONS	PLT38284	1,083	6,188	18,563
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	INTERNALLY DEVELOPED FACTORS						
2	----------						
3	TOTAL GAS PLANT IN SERVICE	PLANT	8,159,970	1,534,126	6,158,307	142,389	78,461
4	SUM OF ALLOCATED LABOR EXP	LABOR	163,741	22,716	98,115	2,219	1,399
5	ACCT 302-FRANCHISE & CONSENTS	PLT302	5,524	766	3,310	75	47
6	ACCT 303-MISC. INTANGIBLE PLANT	PLT303	12,541	1,740	7,515	170	107
7	ACCT 365-LAND & LAND RIGHTS	PLT365	3,096	612	2,535	60	32
8	ACCT 366-STRUCTURES & IMPROV.	PLT366	589	116	482	11	6
9	ACCT 367-MAINS	PLT367	696,026	137,578	569,867	13,555	7,091
10	ACCT 369-MEAS. & REG STATION EQ	PLT369	16,111	3,184	13,191	314	164
11	ACCT 371-OTHER TRANS EQUIP	PLT371	(1,060)	(210)	(868)	(21)	(11)
12	TOTAL TRANSMISSION PLANT	TRANPLT	714,762	141,281	585,207	13,920	7,282
13	ACCT 374-DISTR LAND & LAND RIGHTS	PLT374	8,895	1,758	7,283	173	91
14	ACCT 375-STRUCTURES & IMPROV	PLT375	439	87	359	9	4
15	ACCT 376-MAINS	PLT376	6,113,731	1,208,448	5,005,578	119,063	62,288
16	ACCT 378-MEAS & REG EQ - GEN	PLT378	94,467	18,672	77,344	1,840	962
17	ACCT 379-MEAS & REG EQ - CITY GATE	PLT379	96,304	19,036	78,848	1,875	981
18	ACCT 380-SERVICES	PLT380	591,738	2,760	0	0	2,760
19	ACCT 381-METERS	PLT381	92,810	433	15,837	0	433
20	ACCT 382-METER INSTALLATIONS	PLT382	58,019	271	9,900	0	271
21	ACCT 383-REGULATORS	PLT383	0	0	0	0	0
22	ACCT 384-REGULATOR INSTALLATIONS	PLT384	0	0	0	0	0
23	ACCT 385-INDUSTRIAL MEAS. EQUIP	PLT385	0	85,055	136,088	0	0
24	ACCT 387-OTHER EQUIPMENT	PLT387	40,478	8,001	33,141	788	412
25	ACCT 389-GEN PLT LAND	PLT389	5,835	809	3,496	79	50
26	ACCT 390-STRUCTURES & IMPROVE	PLT390	88,342	12,256	52,935	1,197	755
27	ACCT 391-OFFICE FURN & EQUIP	PLT391	24,681	3,424	14,789	335	211
28	ACCT 392-TRANSPORTATION EQUIP	PLT392	120,031	16,652	71,924	1,627	1,025
29	ACCT 393-STORES EQUIPMENT	PLT393	3,099	430	1,857	42	26
30	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	34,522	4,789	20,686	468	295
31	ACCT 395-LABORATORY EQUIPMENT	PLT395	11,976	1,661	7,176	162	102
32	ACCT 396-POWER OPER EQUIP	PLT396	21,544	2,989	12,909	292	184
33	ACCT 397-COMMUNICATION EQUIP	PLT397	16,039	2,225	9,610	217	137
34	ACCT 398-MISCELLANEOUS EQUIP	PLT398	4,194	582	2,513	57	36
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	0	0	0	0	0
36	ACCT 367 & 376 TOTAL MAINS	PLT367376	6,809,758	1,346,026	5,575,446	132,618	69,379
37	ACCT 376 MAINS + 380 SERVICES	PLT376380	6,705,469	1,211,209	5,005,578	119,063	65,048
38	TOTAL DISTRIBUTION PLANT	DISTRPLT	7,096,880	1,344,521	5,364,379	123,748	68,203
39							
40	ACCT 378 & 379 MEAS. & REG. EQUIP	PLT37879	190,770	37,708	156,192	3,715	1,944
41	ACCT 382 & 384 INSTALLATIONS	PLT38284	58,019	271	9,900	0	271
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	INTERNALLY DEVELOPED FACTORS CONT								
2	---								
3	TOTAL GAS COSTS	GASCOSTS	397,635	243,538	104,183	6,008	21,492	4,055	18,360
4	ACCT 421-PURCHASED POWER EXPENSE	EXP421	0	0	0	0	0	0	0
4	ACCT 805-PURCHASED GAS EXPENSE	EXP805	0	0	0	0	0	0	0
6	ACCT 807-PUR GAS DEMAND	EXP807D	0	0	0	0	0	0	0
7	ACCT 807-PUR GAS COMMODITY	EXP807C	0	0	0	0	0	0	0
8									
9									
10	ACCT 856-MAIN EXPENSE	EXP856	14,172	7,744	3,272	1,885	1,252	12	6
11	ACCT 857-MEAS AND REG STATION	EXP857	0	0	0	0	0	0	0
12	ACCT 864-MAINT OF STATION EQUIP	EXP864	0	0	0	0	0	0	0
13	ACCT 867-MAINT OF OTHER EQUIP	EXP867	349,645	191,053	80,732	46,507	30,897	298	156
14	ACCT 871-LOAD DISPATCHING	EXP871	0	0	0	0	0	0	0
15	ACCT 874-MAINS & SERVICING EXP	EXP874	1,540,668	1,047,585	270,541	130,470	90,778	836	457
16	ACCT 875-MEAS AND REG STATION	EXP875	229,538	125,424	53,000	30,532	20,284	196	102
17	ACCT 876-MEAS AND REG STATION	EXP876	188,393	102,942	43,500	25,059	16,648	161	84
18	ACCT 877-MEAS AND REG STATION	EXP877	28,503	26,240	2,263	0	0	0	0
19	ACCT 878-METER EXPENSE	EXP878	1,485,403	1,345,781	121,867	4,864	12,840	0	51
20	ACCT 879-CUST INSTALL EXPENSE	EXP879	798,365	724,940	65,206	2,252	5,944	0	24
21	ACCT 880-OTHER DISTR EXP	EXP880	1,991,424	1,572,724	259,427	90,074	68,307	556	335
22	ACCT 881-RENTS	EXP881	12,217	6,676	2,821	1,625	1,080	10	5
23	ACCT 886-MAINT OF STRUCTURES	EXP886	973,099	531,722	224,687	129,435	85,990	831	434
24	ACCT 887-MAINT OF MAINS	EXP887	143	78	33	19	13	0	0
25	ACCT 889-MAINT OF MEAS/REG	EXP889	32,400	17,704	7,481	4,310	2,863	28	14
26	ACCT 890-MAINT OF MEAS/REG	EXP890	10,950	5,983	2,528	1,456	968	9	5
27	ACCT 891-MAINT OF MEAS/REG	EXP891	2,845	2,619	226	0	0	0	0
28	ACCT 892-MAINT OF SERVICES	EXP892	586,448	535,647	46,293	119	4,369	0	20
29	ACCT 893-MAINT OF METER	EXP893	333,085	301,776	27,327	1,091	2,879	0	11
30	ACCT 894-MAINT OF OTHER EQUIP	EXP894	53,271	29,109	12,300	7,086	4,707	45	24
31	ACCT 902-METER READING EXP	EXP902	983,242	897,750	77,654	374	7,430	0	34
32	ACCT 903-CUST RECORDS & COLLEC	EXP903	4,002,584	3,655,419	315,885	1,107	30,034	0	138
33	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	688,379	396,154	108,803	140,662	42,423	0	338
34	ACCT 905-MISC CUST ACCT EXP	EXP905	20,265	17,676	1,794	508	285	0	2
35	ACCT 906-CUST SERVICE & INFO	EXP906	0	0	0	0	0	0	0
36	ACCT 908-CUSTOMER ASSISTANCE	EXP908	69,987	63,919	5,523	18	521	2	4
37	ACCT 909-INFO & INSTRUCT ADV	EXP909	104,336	95,290	8,233	27	776	4	6
38	ACCT 910-MISC SERV & INFO	EXP910	700	639	55	0	5	0	0
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	INTERNALLY DEVELOPED FACTORS CONT							
2	----------							
3	TOTAL GAS COSTS	GASCOSTS	99,631	4,552	1,884	4,125	17,577	3,915
4	ACCT 421-PURCHASED POWER EXPENSE	EXP421	0	0	0	0	0	0
4	ACCT 805-PURCHASED GAS EXPENSE	EXP805	0	0	0	0	0	0
6	ACCT 807-PUR GAS DEMAND	EXP807D	0	0	0	0	0	0
7	ACCT 807-PUR GAS COMMODITY	EXP807C	0	0	0	0	0	0
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10	ACCT 856-MAIN EXPENSE	EXP856	2,893	379	57	1,828	621	631
11	ACCT 857-MEAS AND REG STATION	EXP857	0	0	0	0	0	0
12	ACCT 864-MAINT OF STATION EQUIP	EXP864	0	0	0	0	0	0
13	ACCT 867-MAINT OF OTHER EQUIP	EXP867	71,379	9,353	1,415	45,093	15,323	15,574
14	ACCT 871-LOAD DISPATCHING	EXP871	0	0	0	0	0	0
15	ACCT 874-MAINS & SERVICING EXP	EXP874	244,223	26,318	4,042	126,427	47,106	43,673
16	ACCT 875-MEAS AND REG STATION	EXP875	46,859	6,140	929	29,603	10,059	10,224
17	ACCT 876-MEAS AND REG STATION	EXP876	38,460	5,040	762	24,297	8,256	8,392
18	ACCT 877-MEAS AND REG STATION	EXP877	2,263	0	0	0	0	0
19	ACCT 878-METER EXPENSE	EXP878	116,042	5,826	204	4,660	10,925	1,915
20	ACCT 879-CUST INSTALL EXPENSE	EXP879	62,509	2,697	94	2,157	5,057	887
21	ACCT 880-OTHER DISTR EXP	EXP880	237,969	21,459	2,812	87,262	37,957	30,350
22	ACCT 881-RENTS	EXP881	2,494	327	49	1,576	535	544
23	ACCT 886-MAINT OF STRUCTURES	EXP886	198,655	26,032	3,937	125,498	42,645	43,345
24	ACCT 887-MAINT OF MAINS	EXP887	29	4	1	19	6	6
25	ACCT 889-MAINT OF MEAS/REG	EXP889	6,614	867	131	4,179	1,420	1,443
26	ACCT 890-MAINT OF MEAS/REG	EXP890	2,235	293	44	1,412	480	488
27	ACCT 891-MAINT OF MEAS/REG	EXP891	226	0	0	0	0	0
28	ACCT 892-MAINT OF SERVICES	EXP892	46,187	106	81	38	4,348	20
29	ACCT 893-MAINT OF METER	EXP893	26,021	1,306	46	1,045	2,450	429
30	ACCT 894-MAINT OF OTHER EQUIP	EXP894	10,875	1,425	216	6,870	2,335	2,373
31	ACCT 902-METER READING EXP	EXP902	77,410	245	136	238	7,288	143
32	ACCT 903-CUST RECORDS & COLLEC	EXP903	315,193	692	554	554	29,674	360
33	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	83,580	25,223	126	140,536	0	42,423
34	ACCT 905-MISC CUST ACCT EXP	EXP905	1,701	93	3	505	132	153
35	ACCT 906-CUST SERVICE & INFO	EXP906	0	0	0	0	0	0
36	ACCT 908-CUSTOMER ASSISTANCE	EXP908	5,512	11	10	9	1	519
37	ACCT 909-INFO & INSTRUCT ADV	EXP909	8,216	17	14	13	2	774
38	ACCT 910-MISC SERV & INFO	EXP910	55	0	0	0	0	5
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	INTERNALLY DEVELOPED FACTORS CONT						
2	----------						
3	TOTAL GAS COSTS	GASCOSTS	231,519	12,018	99,631	4,552	0
4	ACCT 421-PURCHASED POWER EXPENSE	EXP421	0	0	0	0	0
4	ACCT 805-PURCHASED GAS EXPENSE	EXP805	0	0	0	0	0
6	ACCT 807-PUR GAS DEMAND	EXP807D	0	0	0	0	0
7	ACCT 807-PUR GAS COMMODITY	EXP807C	0	0	0	0	0
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9							
10	ACCT 856-MAIN EXPENSE	EXP856	7,361	383	2,893	129	250
11	ACCT 857-MEAS AND REG STATION	EXP857	0	0	0	0	0
12	ACCT 864-MAINT OF STATION EQUIP	EXP864	0	0	0	0	0
13	ACCT 867-MAINT OF OTHER EQUIP	EXP867	181,595	9,458	71,379	3,183	6,171
14	ACCT 871-LOAD DISPATCHING	EXP871	0	0	0	0	0
15	ACCT 874-MAINS & SERVICING EXP	EXP874	993,627	53,958	244,223	9,022	17,296
16	ACCT 875-MEAS AND REG STATION	EXP875	119,215	6,209	46,859	2,089	4,051
17	ACCT 876-MEAS AND REG STATION	EXP876	97,845	5,096	38,460	1,715	3,325
18	ACCT 877-MEAS AND REG STATION	EXP877	24,834	1,406	2,263	0	0
19	ACCT 878-METER EXPENSE	EXP878	1,273,648	72,132	116,042	3,262	2,563
20	ACCT 879-CUST INSTALL EXPENSE	EXP879	686,084	38,856	62,509	1,510	1,187
21	ACCT 880-OTHER DISTR EXP	EXP880	1,489,885	82,839	237,969	8,206	13,252
22	ACCT 881-RENTS	EXP881	6,345	330	2,494	111	216
23	ACCT 886-MAINT OF STRUCTURES	EXP886	505,398	26,324	198,655	8,858	17,174
24	ACCT 887-MAINT OF MAINS	EXP887	75	4	29	1	3
25	ACCT 889-MAINT OF MEAS/REG	EXP889	16,828	876	6,614	295	572
26	ACCT 890-MAINT OF MEAS/REG	EXP890	5,687	296	2,235	100	193
27	ACCT 891-MAINT OF MEAS/REG	EXP891	2,479	140	226	0	0
28	ACCT 892-MAINT OF SERVICES	EXP892	506,937	28,710	46,187	106	0
29	ACCT 893-MAINT OF METER	EXP893	285,601	16,175	26,021	732	575
30	ACCT 894-MAINT OF OTHER EQUIP	EXP894	27,668	1,441	10,875	485	940
31	ACCT 902-METER READING EXP	EXP902	849,631	48,118	77,410	95	150
32	ACCT 903-CUST RECORDS & COLLEC	EXP903	3,459,493	195,926	315,193	388	305
33	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	375,831	20,322	83,580	3,046	22,177
34	ACCT 905-MISC CUST ACCT EXP	EXP905	16,732	944	1,701	13	81
35	ACCT 906-CUST SERVICE & INFO	EXP906	0	0	0	0	0
36	ACCT 908-CUSTOMER ASSISTANCE	EXP908	60,493	3,426	5,512	7	4
37	ACCT 909-INFO & INSTRUCT ADV	EXP909	90,182	5,107	8,216	10	6
38	ACCT 910-MISC SERV & INFO	EXP910	605	34	55	0	0
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	INTERNALLY DEVELOPED FACTORS CONT				
2					
3	TOTAL GAS COSTS	GASCOSTS	1,884	4,125	0
4	ACCT 421-PURCHASED POWER EXPENSE	EXP421	0	0	0
4	ACCT 805-PURCHASED GAS EXPENSE	EXP805	0	0	0
6	ACCT 807-PUR GAS DEMAND	EXP807D	0	0	0
7	ACCT 807-PUR GAS COMMODITY	EXP807C	0	0	0
8					
9					
10	ACCT 856-MAIN EXPENSE	EXP856	57	105	1,723
11	ACCT 857-MEAS AND REG STATION	EXP857	0	0	0
12	ACCT 864-MAINT OF STATION EQUIP	EXP864	0	0	0
13	ACCT 867-MAINT OF OTHER EQUIP	EXP867	1,415	2,582	42,511
14	ACCT 871-LOAD DISPATCHING	EXP871	0	0	0
15	ACCT 874-MAINS & SERVICING EXP	EXP874	4,042	7,273	119,154
16	ACCT 875-MEAS AND REG STATION	EXP875	929	1,695	27,908
17	ACCT 876-MEAS AND REG STATION	EXP876	762	1,391	22,905
18	ACCT 877-MEAS AND REG STATION	EXP877	0	0	0
19	ACCT 878-METER EXPENSE	EXP878	204	1,165	3,495
20	ACCT 879-CUST INSTALL EXPENSE	EXP879	94	539	1,618
21	ACCT 880-OTHER DISTR EXP	EXP880	2,812	5,625	81,637
22	ACCT 881-RENTS	EXP881	49	90	1,485
23	ACCT 886-MAINT OF STRUCTURES	EXP886	3,937	7,186	118,313
24	ACCT 887-MAINT OF MAINS	EXP887	1	1	17
25	ACCT 889-MAINT OF MEAS/REG	EXP889	131	239	3,939
26	ACCT 890-MAINT OF MEAS/REG	EXP890	44	81	1,331
27	ACCT 891-MAINT OF MEAS/REG	EXP891	0	0	0
28	ACCT 892-MAINT OF SERVICES	EXP892	81	38	0
29	ACCT 893-MAINT OF METER	EXP893	46	261	784
30	ACCT 894-MAINT OF OTHER EQUIP	EXP894	216	393	6,477
31	ACCT 902-METER READING EXP	EXP902	136	34	204
32	ACCT 903-CUST RECORDS & COLLEC	EXP903	554	138	415
33	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	126	189	140,347
34	ACCT 905-MISC CUST ACCT EXP	EXP905	3	1	503
35	ACCT 906-CUST SERVICE & INFO	EXP906	0	0	0
36	ACCT 908-CUSTOMER ASSISTANCE	EXP908	10	2	6
37	ACCT 909-INFO & INSTRUCT ADV	EXP909	14	4	9
38	ACCT 910-MISC SERV & INFO	EXP910	0	0	0
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	INTERNALLY DEVELOPED FACTORS CONT						
2							
3	TOTAL GAS COSTS	GASCOSTS	17,577	3,915	0	4,055	18,360
4	ACCT 421-PURCHASED POWER EXPENSE	EXP421	0	0	0	0	0
4	ACCT 805-PURCHASED GAS EXPENSE	EXP805	0	0	0	0	0
6	ACCT 807-PUR GAS DEMAND	EXP807D	0	0	0	0	0
7	ACCT 807-PUR GAS COMMODITY	EXP807C	0	0	0	0	0
8							
9							
10	ACCT 856-MAIN EXPENSE	EXP856	621	123	509	12	6
11	ACCT 857-MEAS AND REG STATION	EXP857	0	0	0	0	0
12	ACCT 864-MAINT OF STATION EQUIP	EXP864	0	0	0	0	0
13	ACCT 867-MAINT OF OTHER EQUIP	EXP867	15,323	3,029	12,546	298	156
14	ACCT 871-LOAD DISPATCHING	EXP871	0	0	0	0	0
15	ACCT 874-MAINS & SERVICING EXP	EXP874	47,106	8,509	35,164	836	457
16	ACCT 875-MEAS AND REG STATION	EXP875	10,059	1,988	8,236	196	102
17	ACCT 876-MEAS AND REG STATION	EXP876	8,256	1,632	6,760	161	84
18	ACCT 877-MEAS AND REG STATION	EXP877	0	0	0	0	0
19	ACCT 878-METER EXPENSE	EXP878	10,925	51	1,864	0	51
20	ACCT 879-CUST INSTALL EXPENSE	EXP879	5,057	24	863	0	24
21	ACCT 880-OTHER DISTR EXP	EXP880	37,957	5,690	24,660	556	335
22	ACCT 881-RENTS	EXP881	535	106	438	10	5
23	ACCT 886-MAINT OF STRUCTURES	EXP886	42,645	8,429	34,916	831	434
24	ACCT 887-MAINT OF MAINS	EXP887	6	1	5	0	0
25	ACCT 889-MAINT OF MEAS/REG	EXP889	1,420	281	1,163	28	14
26	ACCT 890-MAINT OF MEAS/REG	EXP890	480	95	393	9	5
27	ACCT 891-MAINT OF MEAS/REG	EXP891	0	0	0	0	0
28	ACCT 892-MAINT OF SERVICES	EXP892	4,348	20	0	0	20
29	ACCT 893-MAINT OF METER	EXP893	2,450	11	418	0	11
30	ACCT 894-MAINT OF OTHER EQUIP	EXP894	2,335	461	1,911	45	24
31	ACCT 902-METER READING EXP	EXP902	7,288	34	109	0	34
32	ACCT 903-CUST RECORDS & COLLEC	EXP903	29,674	138	221	0	138
33	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	0	0	42,423	0	338
34	ACCT 905-MISC CUST ACCT EXP	EXP905	132	1	153	0	2
35	ACCT 906-CUST SERVICE & INFO	EXP906	0	0	0	0	0
36	ACCT 908-CUSTOMER ASSISTANCE	EXP908	1	0	519	2	4
37	ACCT 909-INFO & INSTRUCT ADV	EXP909	2	1	774	4	6
38	ACCT 910-MISC SERV & INFO	EXP910	0	0	5	0	0
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	INTERNALLY DEVELOPED FACTORS CONT.								
2	----------								
3	ACCT 912-DEMO & SELLING	EXP912	0	0	0	0	0	0	0
4	ACCT 913-ADVERTISING EXP	EXP913	170	155	13	0	1	0	0
5	ACCT 920-ADMIN & GENERAL SALARY	EXP920	3,335,674	2,710,921	402,587	122,853	98,066	765	482
6	ACCT 921-OFFICE SUPPIES & EXP	EXP921	1,408,798	1,144,938	170,030	51,886	41,418	323	204
7	ACCT 923-OUTSIDE SERVICES	EXP923	(543,925)	(442,051)	(65,647)	(20,033)	(15,991)	(125)	(79)
8	ACCT 924-PROPERTY INSURANCE	EXP924	934,046	759,104	112,731	34,401	27,460	214	135
9	ACCT 925-INJURIES & DAMAGES	EXP925	11,505	9,350	1,388	424	338	3	2
10	ACCT 926-EMPLOYEE PENSION & BENF	EXP926	576,216	468,294	69,544	21,222	16,940	132	83
11	ACCT 928-REG COMMISSION EXP	EXP928	2,622,675	1,879,243	520,437	95,635	122,237	3,350	1,772
12	ACCT 930-MISC GEN EXP	EXP930	992,161	806,335	119,745	36,541	29,169	227	143
13	ACCT 931-RENTS	EXP931	102,113	82,988	12,324	3,761	3,002	23	15
14	ACCT 932-MAINT OF GENERAL PLT	EXP932	350,787	285,087	42,337	12,919	10,313	80	51
15									
16									
17	LABOR ACCT 820-867	LABTM	9,902	5,411	2,286	1,317	875	8	4
18	LABOR ACCT 871-881	LABDO	3,679,056	2,927,141	470,355	158,628	121,363	976	594
19	LABOR ACCT 874-881 & 886-894	LABDM	983,453	710,085	155,571	68,352	48,765	436	244
20	LAROR ACCT 902-906	LABCA	1,624,754	1,483,610	128,283	565	12,240	0	56
21	LABOR ACCT 908-910	LABCS	85,291	77,896	6,730	22	635	3	5
22									
23									
24									
25	ACCTS 902-904	EXP9024	5,674,206	4,949,322	502,342	142,144	79,887	0	510
26	ACCTS 874 - 879	EXP87479	4,270,868	3,372,912	556,376	193,176	146,493	1,193	718
27	ACCTS 908 & 909	EXP9089	174,323	159,209	13,756	46	1,297	6	10
28	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	60,241,006	44,259,622	9,253,306	3,898,231	2,786,686	27,179	15,981
29	TOTAL GENERAL PLANT	GENPLT	19,523,542	15,866,894	2,356,321	719,052	573,977	4,476	2,821
30	WORKING CASH 1/8 OF O&M	WCOM	3,139,593	2,497,472	411,354	125,978	100,328	1,523	2,938
31	PRESENT REVENUE	TOTREV	52,902,507	37,906,597	10,497,835	1,929,075	2,465,675	67,573	35,753
32	PAYROLL EXCLUDING A&G	PAYXAG	6,862,109	5,576,875	828,197	252,731	201,741	1,573	992
33	COMMON PLANT	PLTCOMN	0	0	0	0	0	0	0
34	CHANGE IN REVENUE @ EQUALIZED	REVCHGC	9,480,877	8,121,707	(993,955)	2,015,515	372,840	(35,707)	477
35	CHANGE IN REVENUE @ PROPOSED	REVCHGP	9,480,876	6,675,169	1,974,007	348,061	464,416	12,766	6,458
36	NET PLANT - RESIDENTIAL ONLY	RESNTPT	140,084,522	140,084,522	0	0	0	0	0
37	CAPITALIZED LABOR EXCL ACCT 371	CAPLABX	0	0	0	0	0	0	0
38	WORKING CASH - GAS COSTS	WCGC	397,635	243,538	104,183	6,008	21,492	4,055	18,360
39	WORKING CASH - OTHER	WCOTH	24,719,112	19,736,242	3,186,653	1,001,817	781,130	8,126	5,144
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4	REVENUES FIRM SALES OF GAS								

UNS GAS COMPANY
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		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	INTERNALLY DEVELOPED FACTORS CONT.							
2	---							
3	ACCT 912-DEMO & SELLING	EXP912	0	0	0	0	0	0
4	ACCT 913-ADVERTISING EXP	EXP913	13	0	0	0	1	0
5	ACCT 920-ADMIN & GENERAL SALARY	EXP920	374,206	28,380	3,946	118,907	56,427	41,640
6	ACCT 921-OFFICE SUPPIES & EXP	EXP921	158,043	11,986	1,666	50,220	23,831	17,586
7	ACCT 923-OUTSIDE SERVICES	EXP923	(61,019)	(4,628)	(643)	(19,389)	(9,201)	(6,790)
8	ACCT 924-PROPERTY INSURANCE	EXP924	104,784	7,947	1,105	33,296	15,800	11,660
9	ACCT 925-INJURIES & DAMAGES	EXP925	1,291	98	14	410	195	144
10	ACCT 926-EMPLOYEE PENSION & BENF	EXP926	64,642	4,903	682	20,540	9,747	7,193
11	ACCT 928-REG COMMISSION EXP	EXP928	481,321	39,116	6,734	88,901	81,649	40,588
12	ACCT 930-MISC GEN EXP	EXP930	111,304	8,441	1,174	35,368	16,784	12,385
13	ACCT 931-RENTS	EXP931	11,455	869	121	3,640	1,727	1,275
14	ACCT 932-MAINT OF GENERAL PLT	EXP932	39,352	2,985	415	12,505	5,934	4,379
15								
16								
17	LABOR ACCT 820-867	LABTM	2,021	265	40	1,277	434	441
18	LABOR ACCT 871-881	LABDO	432,058	38,297	4,960	153,669	67,884	53,479
19	LABOR ACCT 874-881 & 886-894	LABDM	141,439	14,132	2,132	66,221	25,868	22,897
20	LAROR ACCT 902-906	LABCA	127,942	341	225	341	12,042	197
21	LABOR ACCT 908-910	LABCS	6,717	14	12	11	2	633
22								
23								
24								
25	ACCTS 902-904	EXP9024	476,183	26,160	816	141,328	36,961	42,925
26	ACCTS 874 - 879	EXP87479	510,355	46,021	6,031	187,145	81,403	65,090
27	ACCTS 908 & 909	EXP9089	13,728	28	24	22	4	1,294
28	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	8,390,746	862,560	148,185	3,750,046	1,471,288	1,315,399
29	TOTAL GENERAL PLANT	GENPLT	2,190,212	166,109	23,094	695,958	330,263	243,714
30	WORKING CASH 1/8 OF O&M	WCOM	380,928	30,426	4,184	121,794	57,044	43,284
31	PRESENT REVENUE	TOTREV	9,708,828	789,007	135,827	1,793,248	1,646,961	818,713
32	PAYROLL EXCLUDING A&G	PAYXAG	769,813	58,384	8,117	244,614	116,080	85,660
33	COMMON PLANT	PLTCOMN	0	0	0	0	0	0
34	CHANGE IN REVENUE @ EQUALIZED	REVCHGC	(1,081,132)	87,178	16,362	1,999,153	(141,397)	514,237
35	CHANGE IN REVENUE @ PROPOSED	REVCHGP	1,825,274	148,732	25,498	322,563	310,889	153,527
36	NET PLANT - RESIDENTIAL ONLY	RESNTPT	0	0	0	0	0	0
37	CAPITALIZED LABOR EXCL ACCT 371	CAPLABX	0	0	0	0	0	0
38	WORKING CASH - GAS COSTS	WCGC	99,631	4,552	1,884	4,125	17,577	3,915
39	WORKING CASH - OTHER	WCOTH	2,947,794	238,859	31,591	970,226	438,772	342,358
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4	REVENUES FIRM SALES OF GAS							

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE (14)	CARES (15)	SM. VOL. (16)	LG. VOL. (17)	TRANS-PORTATION (18)
1	INTERNALLY DEVELOPED FACTORS CONT.						
2	----------						
3	ACCT 912-DEMO & SELLING	EXP912	0	0	0	0	0
4	ACCT 913-ADVERTISING EXP	EXP913	147	8	13	0	0
5	ACCT 920-ADMIN & GENERAL SALARY	EXP920	2,567,619	143,302	374,206	10,656	17,724
6	ACCT 921-OFFICE SUPPIES & EXP	EXP921	1,084,415	60,523	158,043	4,501	7,486
7	ACCT 923-OUTSIDE SERVICES	EXP923	(418,684)	(23,367)	(61,019)	(1,738)	(2,890)
8	ACCT 924-PROPERTY INSURANCE	EXP924	718,977	40,127	104,784	2,984	4,963
9	ACCT 925-INJURIES & DAMAGES	EXP925	8,856	494	1,291	37	61
10	ACCT 926-EMPLOYEE PENSION & BENF	EXP926	443,540	24,755	64,642	1,841	3,062
11	ACCT 928-REG COMMISSION EXP	EXP928	1,806,927	72,316	481,321	12,409	26,707
12	ACCT 930-MISC GEN EXP	EXP930	763,711	42,624	111,304	3,170	5,272
13	ACCT 931-RENTS	EXP931	78,601	4,387	11,455	326	543
14	ACCT 932-MAINT OF GENERAL PLT	EXP932	270,017	15,070	39,352	1,121	1,864
15							
16							
17	LABOR ACCT 820-867	LABTM	5,143	268	2,021	90	175
18	LABOR ACCT 871-881	LABDO	2,772,807	154,333	432,058	14,758	23,538
19	LABOR ACCT 874-881 & 886-894	LABDM	673,167	36,918	141,439	4,941	9,191
20	LAROR ACCT 902-906	LABCA	1,404,090	79,520	127,942	158	182
21	LABOR ACCT 908-910	LABCS	73,721	4,175	6,717	8	5
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24							
25	ACCTS 902-904	EXP9024	4,684,955	264,367	476,183	3,528	22,631
26	ACCTS 874 - 879	EXP87479	3,195,253	177,659	510,355	17,599	28,422
27	ACCTS 908 & 909	EXP9089	150,676	8,533	13,728	17	11
28	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	41,988,651	2,270,971	8,390,746	304,823	557,737
29	TOTAL GENERAL PLANT	GENPLT	15,028,152	838,742	2,190,212	62,371	103,737
30	WORKING CASH 1/8 OF O&M	WCOM	2,368,967	128,506	380,928	10,624	19,803
31	PRESENT REVENUE	TOTREV	36,447,887	1,458,710	9,708,828	250,303	538,704
32	PAYROLL EXCLUDING A&G	PAYXAG	5,282,075	294,800	769,813	21,922	36,461
33	COMMON PLANT	PLTCOMN	0	0	0	0	0
34	CHANGE IN REVENUE @ EQUALIZED	REVCHGC	7,216,422	905,285	(1,081,132)	62,665	24,513
35	CHANGE IN REVENUE @ PROPOSED	REVCHGP	6,675,169	0	1,825,274	45,870	102,862
36	NET PLANT - RESIDENTIAL ONLY	RESNTPT	132,853,027	7,231,495	0	0	0
37	CAPITALIZED LABOR EXCL ACCT 371	CAPLABX	0	0	0	0	0
38	WORKING CASH - GAS COSTS	WCGC	231,519	12,018	99,631	4,552	0
39	WORKING CASH - OTHER	WCOTH	18,720,214	1,016,028	2,947,794	80,438	158,421
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4	REVENUES FIRM SALES OF GAS						

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	INTERNALLY DEVELOPED FACTORS CONT.				
2					
3	ACCT 912-DEMO & SELLING	EXP912	0	0	0
4	ACCT 913-ADVERTISING EXP	EXP913	0	0	0
5	ACCT 920-ADMIN & GENERAL SALARY	EXP920	3,946	7,502	111,405
6	ACCT 921-OFFICE SUPPIES & EXP	EXP921	1,666	3,169	47,051
7	ACCT 923-OUTSIDE SERVICES	EXP923	(643)	(1,223)	(18,166)
8	ACCT 924-PROPERTY INSURANCE	EXP924	1,105	2,101	31,195
9	ACCT 925-INJURIES & DAMAGES	EXP925	14	26	384
10	ACCT 926-EMPLOYEE PENSION & BENF	EXP926	682	1,296	19,244
11	ACCT 928-REG COMMISSION EXP	EXP928	6,734	6,155	82,746
12	ACCT 930-MISC GEN EXP	EXP930	1,174	2,231	33,136
13	ACCT 931-RENTS	EXP931	121	230	3,410
14	ACCT 932-MAINT OF GENERAL PLT	EXP932	415	789	11,716
15					
16					
17	LABOR ACCT 820-867	LABTM	40	73	1,204
18	LABOR ACCT 871-881	LABDO	4,960	10,000	143,669
19	LABOR ACCT 874-881 & 886-894	LABDM	2,132	3,876	62,345
20	LAROR ACCT 902-906	LABCA	225	56	284
21	LABOR ACCT 908-910	LABCS	12	3	8
22					
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24					
25	ACCTS 902-904	EXP9024	816	362	140,966
26	ACCTS 874 - 879	EXP87479	6,031	12,063	175,081
27	ACCTS 908 & 909	EXP9089	24	6	16
28	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	148,185	220,459	3,529,587
29	TOTAL GENERAL PLANT	GENPLT	23,094	43,911	652,047
30	WORKING CASH 1/8 OF O&M	WCOM	4,184	7,095	114,699
31	PRESENT REVENUE	TOTREV	135,827	124,155	1,669,093
32	PAYROLL EXCLUDING A&G	PAYXAG	8,117	15,434	229,181
33	COMMON PLANT	PLTCOMN	0	0	0
34	CHANGE IN REVENUE @ EQUALIZED	REVCHGC	16,362	103,139	1,896,015
35	CHANGE IN REVENUE @ PROPOSED	REVCHGP	25,498	22,603	299,960
36	NET PLANT - RESIDENTIAL ONLY	RESNTPT	0	0	0
37	CAPITALIZED LABOR EXCL ACCT 371	CAPLABX	0	0	0
38	WORKING CASH - GAS COSTS	WCGC	1,884	4,125	0
39	WORKING CASH - OTHER	WCOTH	31,591	52,636	917,590
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4	REVENUES FIRM SALES OF GAS				

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	INTERNALLY DEVELOPED FACTORS CONT.						
2							
3	ACCT 912-DEMO & SELLING	EXP912	0	0	0	0	0
4	ACCT 913-ADVERTISING EXP	EXP913	1	0	0	0	0
5	ACCT 920-ADMIN & GENERAL SALARY	EXP920	56,427	7,828	33,811	765	482
6	ACCT 921-OFFICE SUPPIES & EXP	EXP921	23,831	3,306	14,280	323	204
7	ACCT 923-OUTSIDE SERVICES	EXP923	(9,201)	(1,276)	(5,513)	(125)	(79)
8	ACCT 924-PROPERTY INSURANCE	EXP924	15,800	2,192	9,468	214	135
9	ACCT 925-INJURIES & DAMAGES	EXP925	195	27	117	3	2
10	ACCT 926-EMPLOYEE PENSION & BENF	EXP926	9,747	1,352	5,841	132	83
11	ACCT 928-REG COMMISSION EXP	EXP928	81,649	7,527	33,061	3,350	1,772
12	ACCT 930-MISC GEN EXP	EXP930	16,784	2,328	10,057	227	143
13	ACCT 931-RENTS	EXP931	1,727	240	1,035	23	15
14	ACCT 932-MAINT OF GENERAL PLT	EXP932	5,934	823	3,556	80	51
15							
16							
17	LABOR ACCT 820-867	LABTM	434	86	355	8	4
18	LABOR ACCT 871-881	LABDO	67,884	9,994	43,485	976	594
19	LABOR ACCT 874-881 & 886-894	LABDM	25,868	4,441	18,456	436	244
20	LAROR ACCT 902-906	LABCA	12,042	56	141	0	56
21	LABOR ACCT 908-910	LABCS	2	1	632	3	5
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23							
24							
25	ACCTS 902-904	EXP9024	36,961	172	42,753	0	510
26	ACCTS 874 - 879	EXP87479	81,403	12,203	52,887	1,193	718
27	ACCTS 908 & 909	EXP9089	4	1	1,292	6	10
28	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	1,471,288	248,507	1,066,892	27,179	15,981
29	TOTAL GENERAL PLANT	GENPLT	330,263	45,818	197,897	4,476	2,821
30	WORKING CASH 1/8 OF O&M	WCOM	57,044	7,544	35,740	1,523	2,938
31	PRESENT REVENUE	TOTREV	1,646,961	151,836	666,877	67,573	35,753
32	PAYROLL EXCLUDING A&G	PAYXAG	116,080	16,104	69,556	1,573	992
33	COMMON PLANT	PLTCOMN	0	0	0	0	0
34	CHANGE IN REVENUE @ EQUALIZED	REVCHGC	(141,397)	103,605	410,632	(35,707)	477
35	CHANGE IN REVENUE @ PROPOSED	REVCHGP	310,889	27,932	125,595	12,766	6,458
36	NET PLANT - RESIDENTIAL ONLY	RESNTPT	0	0	0	0	0
37	CAPITALIZED LABOR EXCL ACCT 371	CAPLABX	0	0	0	0	0
38	WORKING CASH - GAS COSTS	WCGC	17,577	3,915	0	4,055	18,360
39	WORKING CASH - OTHER	WCOTH	438,772	56,438	285,920	8,126	5,144
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4	REVENUES FIRM SALES OF GAS						

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	INTERNALLY DEVELOPED FACTORS CONT.								
2	----------								
3	REVENUES FROM GAS SALES								
4	BASE REVENUES		51,157,764	36,381,453	10,351,444	1,888,724	2,435,339	66,940	33,865
5	CUSTOMER AND WEATHER ADJUSTMENT		(1,398,455)	(897,778)	(297,753)	(184,550)	(18,147)	0	(227)
6	ADJ DEMAND TO VOLUMETRIC		0	0	0	0	0	0	0
7	ADJ DEF FARM DISCOUNT CREDITS		0	0	0	0	0	0	0
8	BASE REVENUES PRESENT RATES		52,556,220	37,279,231	10,649,196	2,073,274	2,453,486	66,940	34,092
9	UNBILLED REVENUES		0	0	0	0	0	0	0
10	PGA REVENUES		0	0	0	0	0	0	0
11	LOST MARGIN ADJUSTMENT		0	0	0	0	0	0	0
12									
13	REVENUES FOR RATE DESIGN		51,157,764	36,381,453	10,351,444	1,888,724	2,435,339	66,940	33,865
14									
15									
16	REVENUE REQUIREMENT INPUTS								
17	----------								
18	CLAIMED RATE OF RETURN		9.54%	9.541%	9.541%	9.541%	9.541%	9.541%	9.541%
19	ANNUAL BOOKED THERM SALES		137,141,116	71,600,398	33,670,786	13,348,945	11,931,026	1,192,130	5,397,831
20	PROPOSED SALES REVENUES		60,638,641	43,056,622	12,325,450	2,236,785	2,899,755	79,706	40,322
21	TOTAL YEAR END CUSTOMERS		144,571	132,036	11,408	38	1,076	5	8
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	INTERNALLY DEVELOPED FACTORS CONT.							
2	----------							
3	REVENUES FROM GAS SALES							
4	BASE REVENUES		9,571,509	779,934	133,707	1,755,017	1,630,262	805,077
5	CUSTOMER AND WEATHER ADJUSTMENT		(224,544)	(73,209)	12,438	(196,988)	(47,621)	29,474
6	ADJ DEMAND TO VOLUMETRIC		0	0	0	0	0	0
7	ADJ DEF FARM DISCOUNT CREDITS		0	0	0	0	0	0
8	BASE REVENUES PRESENT RATES		9,796,053	853,143	121,270	1,952,004	1,677,883	775,603
9	UNBILLED REVENUES		0	0	0	0	0	0
10	PGA REVENUES		0	0	0	0	0	0
11	LOST MARGIN ADJUSTMENT		0	0	0	0	0	0
12								
13	REVENUES FOR RATE DESIGN		9,571,509	779,934	133,707	1,755,017	1,630,262	805,077
14								
15								
16	REVENUE REQUIREMENT INPUTS							
17	----------							
18	CLAIMED RATE OF RETURN		9.541%	9.541%	9.541%	9.541%	9.541%	9.541%
19	ANNUAL BOOKED THERM SALES		29,291,657	4,379,129	553,766	12,795,179	5,167,584	6,763,442
20	PROPOSED SALES REVENUES		11,396,784	928,667	159,205	2,077,580	1,941,150	958,604
21	TOTAL YEAR END CUSTOMERS		11,385	23	20	18	3	1,073
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	INTERNALLY DEVELOPED FACTORS CONT.						
2	----------						
3	REVENUES FROM GAS SALES						
4	BASE REVENUES		35,003,749	1,377,705	9,571,509	246,710	533,224
5	CUSTOMER AND WEATHER ADJUSTMENT		(934,080)	36,302	(224,544)	(19,325)	(53,884)
6	ADJ DEMAND TO VOLUMETRIC		0	0	0	0	0
7	ADJ DEF FARM DISCOUNT CREDITS		0	0	0	0	0
8	BASE REVENUES PRESENT RATES		35,937,829	1,341,403	9,796,053	266,035	587,108
9	UNBILLED REVENUES		0	0	0	0	0
10	PGA REVENUES		0	0	0	0	0
11	LOST MARGIN ADJUSTMENT		0	0	0	0	0
12							
13	REVENUES FOR RATE DESIGN		35,003,749	1,377,705	9,571,509	246,710	533,224
14							
15							
16	REVENUE REQUIREMENT INPUTS						
17	----------						
18	CLAIMED RATE OF RETURN		9.54%	9.54%	9.54%	9.54%	9.54%
19	ANNUAL BOOKED THERM SALES		68,066,962	3,533,436	29,291,657	1,338,244	3,040,885
20	PROPOSED SALES REVENUES		41,678,918	1,377,705	11,396,784	292,581	636,086
21	TOTAL YEAR END CUSTOMERS		124,959	7,077	11,385	14	9
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	INTERNALLY DEVELOPED FACTORS CONT.				
2					
3	REVENUES FROM GAS SALES				
4	BASE REVENUES		133,707	121,445	1,633,572
5	CUSTOMER AND WEATHER ADJUSTMENT		12,438	(3,998)	(192,989)
6	ADJ DEMAND TO VOLUMETRIC		0	0	0
7	ADJ DEF FARM DISCOUNT CREDITS		0	0	0
8	BASE REVENUES PRESENT RATES		121,270	125,443	1,826,562
9	UNBILLED REVENUES		0	0	0
10	PGA REVENUES		0	0	0
11	LOST MARGIN ADJUSTMENT		0	0	0
12					
13	REVENUES FOR RATE DESIGN		133,707	121,445	1,633,572
14					
15					
16	REVENUE REQUIREMENT INPUTS				
17					
18	CLAIMED RATE OF RETURN		9.54%	9.54%	9.54%
19	ANNUAL BOOKED THERM SALES		553,766	1,212,653	11,582,526
20	PROPOSED SALES REVENUES		159,205	144,048	1,933,532
21	TOTAL YEAR END CUSTOMERS		20	5	13
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	INTERNALLY DEVELOPED FACTORS CONT.						
2	----------						
3	REVENUES FROM GAS SALES						
4	BASE REVENUES		1,630,262	148,817	656,260	66,940	33,865
5	CUSTOMER AND WEATHER ADJUSTMENT		(47,621)	(3,947)	33,420	0	(227)
6	ADJ DEMAND TO VOLUMETRIC		0	0	0	0	0
7	ADJ DEF FARM DISCOUNT CREDITS		0	0	0	0	0
8	BASE REVENUES PRESENT RATES		1,677,883	152,764	622,840	66,940	34,092
9	UNBILLED REVENUES		0	0	0	0	0
10	PGA REVENUES		0	0	0	0	0
11	LOST MARGIN ADJUSTMENT		0	0	0	0	0
12							
13	REVENUES FOR RATE DESIGN		1,630,262	148,817	656,260	66,940	33,865
14							
15							
16	REVENUE REQUIREMENT INPUTS						
17	----------						
18	CLAIMED RATE OF RETURN		9.54%	9.54%	9.54%	9.54%	9.54%
19	ANNUAL BOOKED THERM SALES		5,167,584	1,151,133	5,612,308	1,192,130	5,397,831
20	PROPOSED SALES REVENUES		1,941,150	176,749	781,855	79,706	40,322
21	TOTAL YEAR END CUSTOMERS		3	1	1,072	5	8
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	ALLOCATION FACTOR TABLE CONT.								
2									
3	INTERNALLY DEVELOPED								
4	---								
5									
6									
7	DEVELOPMENT OF UNCOLLECTABLE FACTOR								
8	RESIDENTIAL REVENUE	RESREV	44,503,160	44,503,160	0	0	0	0	0
9	COMMERCIAL REVENUE	COMREV	8,834,093	0	8,799,752	0	0	0	34,341
10	INDUSTRIAL REVENUE	INDREV	374,652	0	0	374,652	0	0	0
11	TRANSPORTATION REVENUE	TRAREV	5,154,216	0	557,737	3,529,587	1,066,892	0	0
12									
13	ALLOCATION OF BAD DEBTS								
14	RESIDENTIAL	RESREV	396,747	396,747	0	0	0	0	0
15	COMMERCIAL	COMREV	87,094	0	86,755	0	0	0	339
16	INDUSTRIAL	INDREV	316	0	0	316	0	0	0
17	TRANSPORTATION	TRAREV	205,254	0	22,210	140,557	42,486	0	0
18	ALLOCATED BAD DEBTS	BADDEBT	689,410	396,747	108,966	140,873	42,486	0	339
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	ALLOCATION FACTOR TABLE CONT.							
2								
3	INTERNALLY DEVELOPED							
4	----------							
5								
6								
7	DEVELOPMENT OF UNCOLLECTABLE FACTOR							
8	RESIDENTIAL REVENUE	RESREV	0	0	0	0	0	0
9	COMMERCIAL REVENUE	COMREV	8,490,377	309,375	0	0	0	0
10	INDUSTRIAL REVENUE	INDREV	0	0	150,069	224,583	0	0
11	TRANSPORTATION REVENUE	TRAREV	0	557,737	0	3,529,587	0	1,066,892
12								
13	ALLOCATION OF BAD DEBTS							
14	RESIDENTIAL	RESREV	0	0	0	0	0	0
15	COMMERCIAL	COMREV	83,705	3,050	0	0	0	0
16	INDUSTRIAL	INDREV	0	0	127	190	0	0
17	TRANSPORTATION	TRAREV	0	22,210	0	140,557	0	42,486
18	ALLOCATED BAD DEBTS	BADDEBT	83,705	25,261	127	140,746	0	42,486
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	ALLOCATION FACTOR TABLE CONT.						
2							
3	INTERNALLY DEVELOPED						
4	---						
5							
6							
7	DEVELOPMENT OF UNCOLLECTABLE FACTOR						
8	RESIDENTIAL REVENUE	RESREV	42,220,170	2,282,989	0	0	0
9	COMMERCIAL REVENUE	COMREV	0	0	8,490,377	309,375	0
10	INDUSTRIAL REVENUE	INDREV	0	0	0	0	0
11	TRANSPORTATION REVENUE	TRAREV	0	0	0	0	557,737
12							
13	ALLOCATION OF BAD DEBTS						
14	RESIDENTIAL	RESREV	376,394	20,353	0	0	0
15	COMMERCIAL	COMREV	0	0	83,705	3,050	0
16	INDUSTRIAL	INDREV	0	0	0	0	0
17	TRANSPORTATION	TRAREV	0	0	0	0	22,210
18	ALLOCATED BAD DEBTS	BADDEBT	376,394	20,353	83,705	3,050	22,210
19							
20							
21							
22							
23							
24							
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	ALLOCATION FACTOR TABLE CONT.				
2					
3	INTERNALLY DEVELOPED				
4					
5					
6					
7	DEVELOPMENT OF UNCOLLECTABLE FACTOR				
8	RESIDENTIAL REVENUE	RESREV	0	0	0
9	COMMERCIAL REVENUE	COMREV	0	0	0
10	INDUSTRIAL REVENUE	INDREV	150,069	224,583	0
11	TRANSPORTATION REVENUE	TRAREV	0	0	3,529,587
12					
13	ALLOCATION OF BAD DEBTS				
14	RESIDENTIAL	RESREV	0	0	0
15	COMMERCIAL	COMREV	0	0	0
16	INDUSTRIAL	INDREV	127	190	0
17	TRANSPORTATION	TRAREV	0	0	140,557
18	ALLOCATED BAD DEBTS	BADDEBT	127	190	140,557
19					
20					
21					
22					
23					
24					
25					
26					
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	ALLOCATION FACTOR TABLE CONT.						
2							
3	INTERNALLY DEVELOPED						
4	---						
5							
6							
7	DEVELOPMENT OF UNCOLLECTABLE FACTOR						
8	RESIDENTIAL REVENUE	RESREV	0	0	0	0	0
9	COMMERCIAL REVENUE	COMREV	0	0	0	0	34,341
10	INDUSTRIAL REVENUE	INDREV	0	0	0	0	0
11	TRANSPORTATION REVENUE	TRAREV	0	0	1,066,892	0	0
12							
13	ALLOCATION OF BAD DEBTS						
14	RESIDENTIAL	RESREV	0	0	0	0	0
15	COMMERCIAL	COMREV	0	0	0	0	339
16	INDUSTRIAL	INDREV	0	0	0	0	0
17	TRANSPORTATION	TRAREV	0	0	42,486	0	0
18	ALLOCATED BAD DEBTS	BADDEBT	0	0	42,486	0	339
19							
20							
21							
22							
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	INTERNALLY DEVELOPED CONT.								
2	----------								
3	487-FORFEITED DISCOUNTS								
4	REVENUE BY CLASS - RANGE NAME DEFINITION								
5	RESIDENTIAL SERVICE	REV487A	35,003,749	35,003,749	0	0	0	0	0
6									
7	RESIDENTIAL CARES	REV487C	1,377,705	1,377,705	0	0	0	0	0
8	COMMERCIAL SM. VOL.	REV487D	9,571,509	0	9,571,509	0	0	0	0
9									
10	COMMERCIAL LG. VOL.	REV487F	246,710	0	246,710	0	0	0	0
11	COMMERCIAL TRANSPORTATION	REV487G	533,224	0	533,224	0	0	0	0
12	INDUSTRIAL SM. VOL.	REV487H	133,707	0	0	133,707	0	0	0
13	INDUSTRIAL LG. VOL.	REV487I	121,445	0	0	121,445	0	0	0
14	INDUSTRIAL TRANSPORTATION	REV487J	1,633,572	0	0	1,633,572	0	0	0
15	PUBLIC AUTHORITY SM. VOL.	REV487K	1,630,262	0	0	0	1,630,262	0	0
16	PUBLIC AUTHORITY LG. VOL.	REV487L	148,817	0	0	0	148,817	0	0
17	PUBLIC AUTHORITY TRANSPORT.	REV487M	656,260	0	0	0	656,260	0	0
18	IRRIGATION	REV487N	33,865	0	0	0	0	0	33,865
19									
20	487-FORFEITED DISCOUNTS								
21	REVENUE BY CLASS - ALLOCATION								
22	RESIDENTIAL SERVICE	REV487A	347,702	347,702	0	0	0	0	0
23									
24	RESIDENTIAL CARES	REV487C	19,692	19,692	0	0	0	0	0
25	COMMERCIAL SM. VOL.	REV487D	108,913	0	108,913	0	0	0	0
26									
27	COMMERCIAL LG. VOL.	REV487F	134	0	134	0	0	0	0
28	COMMERCIAL TRANSPORTATION	REV487G	536	0	536	0	0	0	0
29	INDUSTRIAL SM. VOL.	REV487H	706	0	0	706	0	0	0
30	INDUSTRIAL LG. VOL.	REV487I	176	0	0	176	0	0	0
31	INDUSTRIAL TRANSPORTATION	REV487J	655	0	0	655	0	0	0
32	PUBLIC AUTHORITY SM. VOL.	REV487K	15,288	0	0	0	15,288	0	0
33	PUBLIC AUTHORITY LG. VOL.	REV487L	72	0	0	0	72	0	0
34	PUBLIC AUTHORITY TRANSPORT.	REV487M	0	0	0	0	0	0	0
35	IRRIGATION	REV487N	1,814	0	0	0	0	0	1,814
36	TOTAL FOREITED DISCOUNTS	FORFDISC	495,690	367,395	109,583	1,538	15,360	0	1,814
37									
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42									

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	INTERNALLY DEVELOPED CONT.							
2	----------							
3	487-FORFEITED DISCOUNTS							
4	REVENUE BY CLASS - RANGE NAME DEFINITION							
5	RESIDENTIAL SERVICE	REV487A	0	0	0	0	0	0
6								
7	RESIDENTIAL CARES	REV487C	0	0	0	0	0	0
8	COMMERCIAL SM. VOL.	REV487D	9,571,509	0	0	0	0	0
9								
10	COMMERCIAL LG. VOL.	REV487F	0	246,710	0	0	0	0
11	COMMERCIAL TRANSPORTATION	REV487G	0	533,224	0	0	0	0
12	INDUSTRIAL SM. VOL.	REV487H	0	0	133,707	0	0	0
13	INDUSTRIAL LG. VOL.	REV487I	0	0	0	121,445	0	0
14	INDUSTRIAL TRANSPORTATION	REV487J	0	0	0	1,633,572	0	0
15	PUBLIC AUTHORITY SM. VOL.	REV487K	0	0	0	0	1,630,262	0
16	PUBLIC AUTHORITY LG. VOL.	REV487L	0	0	0	0	0	148,817
17	PUBLIC AUTHORITY TRANSPORT.	REV487M	0	0	0	0	0	656,260
18	IRRIGATION	REV487N	0	0	0	0	0	0
19								
20	487-FORFEITED DISCOUNTS							
21	REVENUE BY CLASS - ALLOCATION							
22	RESIDENTIAL SERVICE	REV487A	0	0	0	0	0	0
23								
24	RESIDENTIAL CARES	REV487C	0	0	0	0	0	0
25	COMMERCIAL SM. VOL.	REV487D	108,913	0	0	0	0	0
26								
27	COMMERCIAL LG. VOL.	REV487F	0	134	0	0	0	0
28	COMMERCIAL TRANSPORTATION	REV487G	0	536	0	0	0	0
29	INDUSTRIAL SM. VOL.	REV487H	0	0	706	0	0	0
30	INDUSTRIAL LG. VOL.	REV487I	0	0	0	176	0	0
31	INDUSTRIAL TRANSPORTATION	REV487J	0	0	0	655	0	0
32	PUBLIC AUTHORITY SM. VOL.	REV487K	0	0	0	0	15,288	0
33	PUBLIC AUTHORITY LG. VOL.	REV487L	0	0	0	0	0	72
34	PUBLIC AUTHORITY TRANSPORT.	REV487M	0	0	0	0	0	0
35	IRRIGATION	REV487N	0	0	0	0	0	0
36	TOTAL FOREITED DISCOUNTS	FORFDISC	108,913	670	706	832	15,288	72
37								
38								
39								
40								
41								
42								

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	INTERNALLY DEVELOPED CONT.						
2	----------						
3	487-FORFEITED DISCOUNTS						
4	REVENUE BY CLASS - RANGE NAME DEFINITION						
5	RESIDENTIAL SERVICE	REV487A	35,003,749	0	0	0	0
6							
7	RESIDENTIAL CARES	REV487C	0	1,377,705	0	0	0
8	COMMERCIAL SM. VOL.	REV487D	0	0	9,571,509	0	0
9							
10	COMMERCIAL LG. VOL.	REV487F	0	0	0	246,710	0
11	COMMERCIAL TRANSPORTATION	REV487G	0	0	0	0	533,224
12	INDUSTRIAL SM. VOL.	REV487H	0	0	0	0	0
13	INDUSTRIAL LG. VOL.	REV487I	0	0	0	0	0
14	INDUSTRIAL TRANSPORTATION	REV487J	0	0	0	0	0
15	PUBLIC AUTHORITY SM. VOL.	REV487K	0	0	0	0	0
16	PUBLIC AUTHORITY LG. VOL.	REV487L	0	0	0	0	0
17	PUBLIC AUTHORITY TRANSPORT.	REV487M	0	0	0	0	0
18	IRRIGATION	REV487N	0	0	0	0	0
19							
20	487-FORFEITED DISCOUNTS						
21	REVENUE BY CLASS - ALLOCATION						
22	RESIDENTIAL SERVICE	REV487A	347,702	0	0	0	0
23							
24	RESIDENTIAL CARES	REV487C	0	19,692	0	0	0
25	COMMERCIAL SM. VOL.	REV487D	0	0	108,913	0	0
26							
27	COMMERCIAL LG. VOL.	REV487F	0	0	0	134	0
28	COMMERCIAL TRANSPORTATION	REV487G	0	0	0	0	536
29	INDUSTRIAL SM. VOL.	REV487H	0	0	0	0	0
30	INDUSTRIAL LG. VOL.	REV487I	0	0	0	0	0
31	INDUSTRIAL TRANSPORTATION	REV487J	0	0	0	0	0
32	PUBLIC AUTHORITY SM. VOL.	REV487K	0	0	0	0	0
33	PUBLIC AUTHORITY LG. VOL.	REV487L	0	0	0	0	0
34	PUBLIC AUTHORITY TRANSPORT.	REV487M	0	0	0	0	0
35	IRRIGATION	REV487N	0	0	0	0	0
36	TOTAL FOREITED DISCOUNTS	FORFDISC	347,702	19,692	108,913	134	536
37							
38							
39							
40							
41							
42							

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	INTERNALLY DEVELOPED CONT.				
2	---				
3	487-FORFEITED DISCOUNTS				
4	REVENUE BY CLASS - RANGE NAME DEFINITION				
5	RESIDENTIAL SERVICE	REV487A	0	0	0
6					
7	RESIDENTIAL CARES	REV487C	0	0	0
8	COMMERCIAL SM. VOL.	REV487D	0	0	0
9					
10	COMMERCIAL LG. VOL.	REV487F	0	0	0
11	COMMERCIAL TRANSPORTATION	REV487G	0	0	0
12	INDUSTRIAL SM. VOL.	REV487H	133,707	0	0
13	INDUSTRIAL LG. VOL.	REV487I	0	121,445	0
14	INDUSTRIAL TRANSPORTATION	REV487J	0	0	1,633,572
15	PUBLIC AUTHORITY SM. VOL.	REV487K	0	0	0
16	PUBLIC AUTHORITY LG. VOL.	REV487L	0	0	0
17	PUBLIC AUTHORITY TRANSPORT.	REV487M	0	0	0
18	IRRIGATION	REV487N	0	0	0
19					
20	487-FORFEITED DISCOUNTS				
21	REVENUE BY CLASS - ALLOCATION				
22	RESIDENTIAL SERVICE	REV487A	0	0	0
23					
24	RESIDENTIAL CARES	REV487C	0	0	0
25	COMMERCIAL SM. VOL.	REV487D	0	0	0
26					
27	COMMERCIAL LG. VOL.	REV487F	0	0	0
28	COMMERCIAL TRANSPORTATION	REV487G	0	0	0
29	INDUSTRIAL SM. VOL.	REV487H	706	0	0
30	INDUSTRIAL LG. VOL.	REV487I	0	176	0
31	INDUSTRIAL TRANSPORTATION	REV487J	0	0	655
32	PUBLIC AUTHORITY SM. VOL.	REV487K	0	0	0
33	PUBLIC AUTHORITY LG. VOL.	REV487L	0	0	0
34	PUBLIC AUTHORITY TRANSPORT.	REV487M	0	0	0
35	IRRIGATION	REV487N	0	0	0
36	TOTAL FOREITED DISCOUNTS	FORFDISC	706	176	655
37					
38					
39					
40					
41					
42					

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	INTERNALLY DEVELOPED CONT.						
2	----------						
3	487-FORFEITED DISCOUNTS						
4	REVENUE BY CLASS - RANGE NAME DEFINITION						
5	RESIDENTIAL SERVICE	REV487A	0	0	0	0	0
6							
7	RESIDENTIAL CARES	REV487C	0	0	0	0	0
8	COMMERCIAL SM. VOL.	REV487D	0	0	0	0	0
9							
10	COMMERCIAL LG. VOL.	REV487F	0	0	0	0	0
11	COMMERCIAL TRANSPORTATION	REV487G	0	0	0	0	0
12	INDUSTRIAL SM. VOL.	REV487H	0	0	0	0	0
13	INDUSTRIAL LG. VOL.	REV487I	0	0	0	0	0
14	INDUSTRIAL TRANSPORTATION	REV487J	0	0	0	0	0
15	PUBLIC AUTHORITY SM. VOL.	REV487K	1,630,262	0	0	0	0
16	PUBLIC AUTHORITY LG. VOL.	REV487L	0	148,817	0	0	0
17	PUBLIC AUTHORITY TRANSPORT.	REV487M	0	0	656,260	0	0
18	IRRIGATION	REV487N	0	0	0	0	33,865
19							
20	487-FORFEITED DISCOUNTS						
21	REVENUE BY CLASS - ALLOCATION						
22	RESIDENTIAL SERVICE	REV487A	0	0	0	0	0
23							
24	RESIDENTIAL CARES	REV487C	0	0	0	0	0
25	COMMERCIAL SM. VOL.	REV487D	0	0	0	0	0
26							
27	COMMERCIAL LG. VOL.	REV487F	0	0	0	0	0
28	COMMERCIAL TRANSPORTATION	REV487G	0	0	0	0	0
29	INDUSTRIAL SM. VOL.	REV487H	0	0	0	0	0
30	INDUSTRIAL LG. VOL.	REV487I	0	0	0	0	0
31	INDUSTRIAL TRANSPORTATION	REV487J	0	0	0	0	0
32	PUBLIC AUTHORITY SM. VOL.	REV487K	15,288	0	0	0	0
33	PUBLIC AUTHORITY LG. VOL.	REV487L	0	72	0	0	0
34	PUBLIC AUTHORITY TRANSPORT.	REV487M	0	0	0	0	0
35	IRRIGATION	REV487N	0	0	0	0	1,814
36	TOTAL FOREITED DISCOUNTS	FORFDISC	15,288	72	0	0	1,814
37							
38							
39							
40							
41							
42							

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	RATIO TABLE								
2	CAPACITY RELATED								
3									
4	PRODUCTION ALLOCATORS								
5	ANNUAL FIRM THERM THROUGHPUT	DEMGAS	1.00000	0.61246	0.26201	0.01511	0.05405	0.01020	0.04617
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22	TRANSMISSION ALLOCATORS								
23									
24	PROPORTIONAL RESPONSIBILITY	TRANS	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
25									
26									
27									
28									
29									
30									
34	DISTRIBUTION ALLOCATORS								
35									
33	PROPORTIONAL RESPONSIBILITY	DISTR	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
34	DISTRIBUTION MAINS	DISTMAIN	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
35	DISTRIBUTION REGULATORS	DISTREG	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
36									
37									
38									
39									
40									
41									
42									
43	PROPORTIONAL RESPONSIBILITY		1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
44									
45									

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			COMMERCIAL		INDUSTRIAL		PUBLIC AUTHORITY	
		ALLOC	SM. VOL. (8)	LG. VOL. (9)	SM. VOL. (10)	LG. VOL. (11)	SM. VOL. (12)	LG. VOL. (13)
1	RATIO TABLE							
2	CAPACITY RELATED							
3								
4	PRODUCTION ALLOCATORS							
5	ANNUAL FIRM THERM THROUGHPUT	DEMGAS	0.25056	0.01145	0.00474	0.01037	0.04420	0.00985
22	TRANSMISSION ALLOCATORS							
23								
24	PROPORTIONAL RESPONSIBILITY	TRANS	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
34	DISTRIBUTION ALLOCATORS							
35								
33	PROPORTIONAL RESPONSIBILITY	DISTR	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
34	DISTRIBUTION MAINS	DISTMAIN	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
35	DISTRIBUTION REGULATORS	DISTREG	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
43	PROPORTIONAL RESPONSIBILITY		0.20415	0.02675	0.00405	0.12897	0.04382	0.04454

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			RESIDENTIAL		COMMERCIAL		
		ALLOC	RESIDENTIAL SERVICE (14)	CARES (15)	SM. VOL. (16)	LG. VOL. (17)	TRANS-PORTATION (18)
1	RATIO TABLE						
2	CAPACITY RELATED						
3							
4	PRODUCTION ALLOCATORS						
5	ANNUAL FIRM THERM THROUGHPUT	DEMGAS	0.58224	0.03022	0.25056	0.01145	0.00000
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22	TRANSMISSION ALLOCATORS						
23							
24	PROPORTIONAL RESPONSIBILITY	TRANS	0.51937	0.02705	0.20415	0.00910	0.01765
25							
26							
27							
28							
29							
30							
34	DISTRIBUTION ALLOCATORS						
35							
33	PROPORTIONAL RESPONSIBILITY	DISTR	0.51937	0.02705	0.20415	0.00910	0.01765
34	DISTRIBUTION MAINS	DISTMAIN	0.51937	0.02705	0.20415	0.00910	0.01765
35	DISTRIBUTION REGULATORS	DISTREG	0.51937	0.02705	0.20415	0.00910	0.01765
36							
37							
38							
39							
40							
41							
42							
43	PROPORTIONAL RESPONSIBILITY		0.51937	0.02705	0.20415	0.00910	0.01765
44							
45							

UNS GAS COMPANY
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			INDUSTRIAL		
		ALLOC	SM. VOL. (19)	LG. VOL. (20)	TRANS-PORTATION (21)
1	RATIO TABLE				
2	CAPACITY RELATED				
3					
4	PRODUCTION ALLOCATORS				
5	ANNUAL FIRM THERM THROUGHPUT	DEMGAS	0.00474	0.01037	0.00000
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22	TRANSMISSION ALLOCATORS				
23					
24	PROPORTIONAL RESPONSIBILITY	TRANS	0.00405	0.00738	0.12158
25					
26					
27					
28					
29					
30					
34	DISTRIBUTION ALLOCATORS				
35					
33	PROPORTIONAL RESPONSIBILITY	DISTR	0.00405	0.00738	0.12158
34	DISTRIBUTION MAINS	DISTMAIN	0.00405	0.00738	0.12158
35	DISTRIBUTION REGULATORS	DISTREG	0.00405	0.00738	0.12158
36					
37					
38					
39					
40					
41					
42					
43	PROPORTIONAL RESPONSIBILITY		0.00405	0.00738	0.12158
44					
45					

UNS GAS COMPANY
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			PUBLIC AUTHORITY				
		ALLOC	SM. VOL. (22)	LG. VOL. (23)	TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	RATIO TABLE						
2	CAPACITY RELATED						
3							
4	PRODUCTION ALLOCATORS						
5	ANNUAL FIRM THERM THROUGHPUT	DEMGAS	0.04420	0.00985	0.00000	0.01020	0.04617
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22	TRANSMISSION ALLOCATORS						
23							
24	PROPORTIONAL RESPONSIBILITY	TRANS	0.04382	0.00866	0.03588	0.00085	0.00045
25							
26							
27							
28							
29							
30							
34	DISTRIBUTION ALLOCATORS						
35							
33	PROPORTIONAL RESPONSIBILITY	DISTR	0.04382	0.00866	0.03588	0.00085	0.00045
34	DISTRIBUTION MAINS	DISTMAIN	0.04382	0.00866	0.03588	0.00085	0.00045
35	DISTRIBUTION REGULATORS	DISTREG	0.04382	0.00866	0.03588	0.00085	0.00045
36							
37							
38							
39							
40							
41							
42							
43	PROPORTIONAL RESPONSIBILITY		0.04382	0.00866	0.03588	0.00085	0.00045
44							
45							

UNS GAS COMPANY
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		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	RATIO TABLE CONT.								
2	COMMODITY RELATED								
3	----------								
4	ANNUAL FIRM THERM THROUGHPUT	GASSALES	1.00000	0.61246	0.26201	0.01511	0.05405	0.01020	0.04617
5			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
6			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
7	ANNUAL FIRM THERM THROUGHPUT	THERMS	1.00000	0.52209	0.24552	0.09734	0.08700	0.00869	0.03936
8	CARES	CARES	1.00000	0.50945	0.25201	0.09991	0.08930	0.00892	0.04040
9									
10									
11									
12									
13									
14									
15									
16	CUSTOMER RELATED								
17	----------								
18	YEAR END NUMBER OF CUSTOMERS	CUST10	1.00000	0.91330	0.07891	0.00026	0.00744	0.00003	0.00006
19	ACCT 380-SERVICES	CUST380	1.00000	0.91338	0.07894	0.00020	0.00745	0.00000	0.00003
20	ACCT 381-METERS	CUST381	1.00000	0.90600	0.08204	0.00327	0.00864	0.00000	0.00003
21	ACCT 382-METER INSTALLATIONS	CUST382	1.00000	0.90600	0.08204	0.00327	0.00864	0.00000	0.00003
22	ACCT 383-HOUSE REGULATORS	CUST383	1.00000	0.92062	0.07938	0.00000	0.00000	0.00000	0.00000
23	ACCT 384-HOUSE REG. INSTALLATION	CUST384	1.00000	0.92062	0.07938	0.00000	0.00000	0.00000	0.00000
24	ACCT 385-INDUSTRIAL REG EQUIP	CUST385	1.00000	0.00000	0.32051	0.51282	0.16667	0.00000	0.00000
25	CUSTOMER DEPOSITS	CUSTDEP	1.00000	0.77342	0.22658	0.00000	0.00000	0.00000	0.00000
26									
27									
28	ACCT 487-MISC. SERVICE REVENUE	CUST487B	1.00000	0.95539	0.04368	0.00013	0.00079	0.00000	0.00000
29									
30	ACCT 902-METER READ EXP	CUST902	1.00000	0.91305	0.07898	0.00038	0.00756	0.00000	0.00003
31	ACCT 903-CUST RECORDS & COLL	CUST903	1.00000	0.91326	0.07892	0.00028	0.00750	0.00000	0.00003
32	ACCT 912-DEMO & SELLING	CDA912	1.00000	0.91376	0.07879	0.00000	0.00745	0.00000	0.00000
33	ACCT 913-ADVERTISING EXPENSES	CDA913	1.00000	0.91376	0.07879	0.00000	0.00745	0.00000	0.00000
34									
35									
36									
37									
38									
39									
40									
41									
42									
43									
44									
45									

UNS GAS COMPANY
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		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	RATIO TABLE CONT.							
2	COMMODITY RELATED							
3	----------							
4	ANNUAL FIRM THERM THROUGHPUT	GASSALES	0.25056	0.01145	0.00474	0.01037	0.04420	0.00985
5			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
6			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
7	ANNUAL FIRM THERM THROUGHPUT	THERMS	0.21359	0.03193	0.00404	0.09330	0.03768	0.04932
8	CARES	CARES	0.21924	0.03278	0.00414	0.09577	0.03868	0.05062
9								
10								
11								
12								
13								
14								
15								
16	CUSTOMER RELATED							
17	----------							
18	YEAR END NUMBER OF CUSTOMERS	CUST10	0.07875	0.00016	0.00014	0.00012	0.00002	0.00742
19	ACCT 380-SERVICES	CUST380	0.07876	0.00018	0.00014	0.00006	0.00741	0.00003
20	ACCT 381-METERS	CUST381	0.07812	0.00392	0.00014	0.00314	0.00735	0.00129
21	ACCT 382-METER INSTALLATIONS	CUST382	0.07812	0.00392	0.00014	0.00314	0.00735	0.00129
22	ACCT 383-HOUSE REGULATORS	CUST383	0.07938	0.00000	0.00000	0.00000	0.00000	0.00000
23	ACCT 384-HOUSE REG. INSTALLATION	CUST384	0.07938	0.00000	0.00000	0.00000	0.00000	0.00000
24	ACCT 385-INDUSTRIAL REG EQUIP	CUST385	0.00000	0.32051	0.25641	0.25641	0.00000	0.16667
25	CUSTOMER DEPOSITS	CUSTDEP	0.22630	0.00028	0.00000	0.00000	0.00000	0.00000
26								
27								
28	ACCT 487-MISC. SERVICE REVENUE	CUST487B	0.04368	0.00000	0.00013	0.00000	0.00079	0.00000
29								
30	ACCT 902-METER READ EXP	CUST902	0.07873	0.00025	0.00014	0.00024	0.00741	0.00015
31	ACCT 903-CUST RECORDS & COLL	CUST903	0.07875	0.00017	0.00014	0.00014	0.00741	0.00009
32	ACCT 912-DEMO & SELLING	CDA912	0.07879	0.00000	0.00000	0.00000	0.00742	0.00003
33	ACCT 913-ADVERTISING EXPENSES	CDA913	0.07879	0.00000	0.00000	0.00000	0.00742	0.00003
34								
35								
36								
37								
38								
39								
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42								
43								
44								
45								

UNS GAS COMPANY
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			RESIDENTIAL		COMMERCIAL		
		ALLOC	RESIDENTIAL SERVICE (14)	CARES (15)	SM. VOL. (16)	LG. VOL. (17)	TRANS-PORTATION (18)
1	RATIO TABLE CONT.						
2	COMMODITY RELATED						
3							
4	ANNUAL FIRM THERM THROUGHPUT	GASSALES	0.58224	0.03022	0.25056	0.01145	0.00000
5			0.00000	0.00000	0.00000	0.00000	0.00000
6			0.00000	0.00000	0.00000	0.00000	0.00000
7	ANNUAL FIRM THERM THROUGHPUT	THERMS	0.49633	0.02576	0.21359	0.00976	0.02217
8	CARES	CARES	0.50945	0.00000	0.21924	0.01002	0.02276
9							
10							
11							
12							
13							
14							
15							
16	CUSTOMER RELATED						
17							
18	YEAR END NUMBER OF CUSTOMERS	CUST10	0.86434	0.04895	0.07875	0.00010	0.00006
19	ACCT 380-SERVICES	CUST380	0.86442	0.04896	0.07876	0.00018	0.00000
20	ACCT 381-METERS	CUST381	0.85744	0.04856	0.07812	0.00220	0.00173
21	ACCT 382-METER INSTALLATIONS	CUST382	0.85744	0.04856	0.07812	0.00220	0.00173
22	ACCT 383-HOUSE REGULATORS	CUST383	0.87127	0.04934	0.07938	0.00000	0.00000
23	ACCT 384-HOUSE REG. INSTALLATION	CUST384	0.87127	0.04934	0.07938	0.00000	0.00000
24	ACCT 385-INDUSTRIAL REG EQUIP	CUST385	0.00000	0.00000	0.00000	0.17949	0.14103
25	CUSTOMER DEPOSITS	CUSTDEP	0.73197	0.04145	0.22630	0.00028	0.00000
26							
27							
28	ACCT 487-MISC. SERVICE REVENUE	CUST487B	0.90419	0.05121	0.04368	0.00000	0.00000
29							
30	ACCT 902-METER READ EXP	CUST902	0.86411	0.04894	0.07873	0.00010	0.00015
31	ACCT 903-CUST RECORDS & COLL	CUST903	0.86431	0.04895	0.07875	0.00010	0.00008
32	ACCT 912-DEMO & SELLING	CDA912	0.86478	0.04898	0.07879	0.00000	0.00000
33	ACCT 913-ADVERTISING EXPENSES	CDA913	0.86478	0.04898	0.07879	0.00000	0.00000
34							
35							
36							
37							
38							
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43							
44							
45							

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			INDUSTRIAL		
		ALLOC	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(19)	(20)	(21)
1	RATIO TABLE CONT.				
2	COMMODITY RELATED				
3	----------				
4	ANNUAL FIRM THERM THROUGHPUT	GASSALES	0.00474	0.01037	0.00000
5			0.00000	0.00000	0.00000
6			0.00000	0.00000	0.00000
7	ANNUAL FIRM THERM THROUGHPUT	THERMS	0.00404	0.00884	0.08446
8	CARES	CARES	0.00414	0.00908	0.08669
9					
10					
11					
12					
13					
14					
15					
16	CUSTOMER RELATED				
17	----------				
18	YEAR END NUMBER OF CUSTOMERS	CUST10	0.00014	0.00003	0.00009
19	ACCT 380-SERVICES	CUST380	0.00014	0.00006	0.00000
20	ACCT 381-METERS	CUST381	0.00014	0.00078	0.00235
21	ACCT 382-METER INSTALLATIONS	CUST382	0.00014	0.00078	0.00235
22	ACCT 383-HOUSE REGULATORS	CUST383	0.00000	0.00000	0.00000
23	ACCT 384-HOUSE REG. INSTALLATION	CUST384	0.00000	0.00000	0.00000
24	ACCT 385-INDUSTRIAL REG EQUIP	CUST385	0.25641	0.06410	0.19231
25	CUSTOMER DEPOSITS	CUSTDEP	0.00000	0.00000	0.00000
26					
27					
28	ACCT 487-MISC. SERVICE REVENUE	CUST487B	0.00013	0.00000	0.00000
29					
30	ACCT 902-METER READ EXP	CUST902	0.00014	0.00003	0.00021
31	ACCT 903-CUST RECORDS & COLL	CUST903	0.00014	0.00003	0.00010
32	ACCT 912-DEMO & SELLING	CDA912	0.00000	0.00000	0.00000
33	ACCT 913-ADVERTISING EXPENSES	CDA913	0.00000	0.00000	0.00000
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					

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			PUBLIC AUTHORITY				
		ALLOC	SM. VOL. (22)	LG. VOL. (23)	TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	RATIO TABLE CONT.						
2	COMMODITY RELATED						
3	----------						
4	ANNUAL FIRM THERM THROUGHPUT	GASSALES	0.04420	0.00985	0.00000	0.01020	0.04617
5			0.00000	0.00000	0.00000	0.00000	0.00000
6			0.00000	0.00000	0.00000	0.00000	0.00000
7	ANNUAL FIRM THERM THROUGHPUT	THERMS	0.03768	0.00839	0.04092	0.00869	0.03936
8	CARES	CARES	0.03868	0.00862	0.04201	0.00892	0.04040
9							
10							
11							
12							
13							
14							
15							
16	CUSTOMER RELATED						
17	----------						
18	YEAR END NUMBER OF CUSTOMERS	CUST10	0.00002	0.00001	0.00741	0.00003	0.00006
19	ACCT 380-SERVICES	CUST380	0.00741	0.00003	0.00000	0.00000	0.00003
20	ACCT 381-METERS	CUST381	0.00735	0.00003	0.00125	0.00000	0.00003
21	ACCT 382-METER INSTALLATIONS	CUST382	0.00735	0.00003	0.00125	0.00000	0.00003
22	ACCT 383-HOUSE REGULATORS	CUST383	0.00000	0.00000	0.00000	0.00000	0.00000
23	ACCT 384-HOUSE REG. INSTALLATION	CUST384	0.00000	0.00000	0.00000	0.00000	0.00000
24	ACCT 385-INDUSTRIAL REG EQUIP	CUST385	0.00000	0.06410	0.10256	0.00000	0.00000
25	CUSTOMER DEPOSITS	CUSTDEP	0.00000	0.00000	0.00000	0.00000	0.00000
26							
27							
28	ACCT 487-MISC. SERVICE REVENUE	CUST487B	0.00079	0.00000	0.00000	0.00000	0.00000
29							
30	ACCT 902-METER READ EXP	CUST902	0.00741	0.00003	0.00011	0.00000	0.00003
31	ACCT 903-CUST RECORDS & COLL	CUST903	0.00741	0.00003	0.00006	0.00000	0.00003
32	ACCT 912-DEMO & SELLING	CDA912	0.00742	0.00003	0.00000	0.00000	0.00000
33	ACCT 913-ADVERTISING EXPENSES	CDA913	0.00742	0.00003	0.00000	0.00000	0.00000
34							
35							
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43							
44							
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		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	INTERNALLY DEVELOPED RATIOS								
2	----------								
3	TOTAL GAS PLANT IN SERVICE	PLANT	1.00000	0.69565	0.16852	0.07992	0.05514	0.00050	0.00027
4	SUM OF ALLOCATED LABOR EXP	LABOR	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
5	ACCT 302-FRANCHISE & CONSENTS	PLT302	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
6	ACCT 303-MISC. INTANGIBLE PLANT	PLT303	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
7	ACCT 365-LAND & LAND RIGHTS	PLT365	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
8	ACCT 366-STRUCTURES & IMPROV.	PLT366	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
9	ACCT 367-MAINS	PLT367	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
10	ACCT 369-MEAS. & REG STATION EQ	PLT369	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
11	ACCT 371-OTHER TRANS EQUIP	PLT371	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
12	TOTAL TRANSMISSION PLANT	TRANPLT	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
13	ACCT 374-DISTR LAND & LAND RIGHTS	PLT374	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
14	ACCT 375-STRUCTURES & IMPROV	PLT375	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
15	ACCT 376-MAINS	PLT376	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
16	ACCT 378-MEAS & REG EQ - GEN	PLT378	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
17	ACCT 379-MEAS & REG EQ - CITY GATE	PLT379	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
18	ACCT 380-SERVICES	PLT380	1.00000	0.91338	0.07894	0.00020	0.00745	0.00000	0.00003
19	ACCT 381-METERS	PLT381	1.00000	0.90600	0.08204	0.00327	0.00864	0.00000	0.00003
20	ACCT 382-METER INSTALLATIONS	PLT382	1.00000	0.90600	0.08204	0.00327	0.00864	0.00000	0.00003
21	ACCT 383-REGULATORS	PLT383	1.00000	0.92062	0.07938	0.00000	0.00000	0.00000	0.00000
22	ACCT 384-REGULATOR INSTALLATIONS	PLT384	1.00000	0.92062	0.07938	0.00000	0.00000	0.00000	0.00000
23	ACCT 385-INDUSTRIAL MEAS. EQUIP	PLT385	1.00000	0.00000	0.32051	0.51282	0.16667	0.00000	0.00000
24	ACCT 387-OTHER EQUIPMENT	PLT387	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
25	ACCT 389-GEN PLT LAND	PLT389	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
26	ACCT 390-STRUCTURES & IMPROVE	PLT390	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
27	ACCT 391-OFFICE FURN & EQUIP	PLT391	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
28	ACCT 392-TRANSPORTATION EQUIP	PLT392	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
29	ACCT 393-STORES EQUIPMENT	PLT393	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
30	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
31	ACCT 395-LABORATORY EQUIPMENT	PLT395	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
32	ACCT 396-POWER OPER EQUIP	PLT396	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
33	ACCT 397-COMMUNICATION EQUIP	PLT397	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
34	ACCT 398-MISCELLANEOUS EQUIP	PLT398	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
36	ACCT 367 & 376 TOTAL MAINS	PLT367376	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
37	ACCT 376 MAINS + 380 SERVICES	PLT376380	1.00000	0.67996	0.17560	0.08468	0.05892	0.00054	0.00030
38	TOTAL DISTRIBUTION PLANT	DISTRPLT	1.00000	0.69575	0.16840	0.08000	0.05509	0.00049	0.00027
39									
40	ACCT 378 & 379 MEAS. & REG. EQUIP	PLT37879	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
41	ACCT 382 & 384 INSTALLATIONS	PLT38284	1.00000	0.90803	0.08167	0.00282	0.00745	0.00000	0.00003
42									
43									
44									
45									

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			COMMERCIAL		INDUSTRIAL		PUBLIC AUTHORITY	
		ALLOC	SM. VOL. (8)	LG. VOL. (9)	SM. VOL. (10)	LG. VOL. (11)	SM. VOL. (12)	LG. VOL. (13)
1	INTERNALLY DEVELOPED RATIOS							
2								
3	TOTAL GAS PLANT IN SERVICE	PLANT	0.15110	0.01743	0.00359	0.07633	0.02838	0.02675
4	SUM OF ALLOCATED LABOR EXP	LABOR	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
5	ACCT 302-FRANCHISE & CONSENTS	PLT302	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
6	ACCT 303-MISC. INTANGIBLE PLANT	PLT303	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
7	ACCT 365-LAND & LAND RIGHTS	PLT365	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
8	ACCT 366-STRUCTURES & IMPROV.	PLT366	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
9	ACCT 367-MAINS	PLT367	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
10	ACCT 369-MEAS. & REG STATION EQ	PLT369	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
11	ACCT 371-OTHER TRANS EQUIP	PLT371	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
12	TOTAL TRANSMISSION PLANT	TRANPLT	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
13	ACCT 374-DISTR LAND & LAND RIGHTS	PLT374	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
14	ACCT 375-STRUCTURES & IMPROV	PLT375	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
15	ACCT 376-MAINS	PLT376	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
16	ACCT 378-MEAS & REG EQ - GEN	PLT378	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
17	ACCT 379-MEAS & REG EQ - CITY GATE	PLT379	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
18	ACCT 380-SERVICES	PLT380	0.07876	0.00018	0.00014	0.00006	0.00741	0.00003
19	ACCT 381-METERS	PLT381	0.07812	0.00392	0.00014	0.00314	0.00735	0.00129
20	ACCT 382-METER INSTALLATIONS	PLT382	0.07812	0.00392	0.00014	0.00314	0.00735	0.00129
21	ACCT 383-REGULATORS	PLT383	0.07938	0.00000	0.00000	0.00000	0.00000	0.00000
22	ACCT 384-REGULATOR INSTALLATIONS	PLT384	0.07938	0.00000	0.00000	0.00000	0.00000	0.00000
23	ACCT 385-INDUSTRIAL MEAS. EQUIP	PLT385	0.00000	0.32051	0.25641	0.25641	0.00000	0.16667
24	ACCT 387-OTHER EQUIPMENT	PLT387	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
25	ACCT 389-GEN PLT LAND	PLT389	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
26	ACCT 390-STRUCTURES & IMPROVE	PLT390	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
27	ACCT 391-OFFICE FURN & EQUIP	PLT391	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
28	ACCT 392-TRANSPORTATION EQUIP	PLT392	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
29	ACCT 393-STORES EQUIPMENT	PLT393	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
30	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
31	ACCT 395-LABORATORY EQUIPMENT	PLT395	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
32	ACCT 396-POWER OPER EQUIP	PLT396	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
33	ACCT 397-COMMUNICATION EQUIP	PLT397	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
34	ACCT 398-MISCELLANEOUS EQUIP	PLT398	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
36	ACCT 367 & 376 TOTAL MAINS	PLT367376	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
37	ACCT 376 MAINS + 380 SERVICES	PLT376380	0.15852	0.01708	0.00262	0.08206	0.03057	0.02835
38	TOTAL DISTRIBUTION PLANT	DISTRPLT	0.15084	0.01755	0.00375	0.07625	0.02832	0.02677
39								
40	ACCT 378 & 379 MEAS. & REG. EQUIP	PLT37879	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
41	ACCT 382 & 384 INSTALLATIONS	PLT38284	0.07830	0.00338	0.00012	0.00270	0.00633	0.00111
42								
43								
44								
45								

UNS GAS COMPANY
COST OF SERVICE STUDY
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			RESIDENTIAL		COMMERCIAL		
		ALLOC	RESIDENTIAL SERVICE (14)	CARES (15)	SM. VOL. (16)	LG. VOL. (17)	TRANS-PORTATION (18)
1	INTERNALLY DEVELOPED RATIOS						
2							
3	TOTAL GAS PLANT IN SERVICE	PLANT	0.65966	0.03599	0.15110	0.00637	0.01106
4	SUM OF ALLOCATED LABOR EXP	LABOR	0.76975	0.04296	0.11218	0.00319	0.00531
5	ACCT 302-FRANCHISE & CONSENTS	PLT302	0.76975	0.04296	0.11218	0.00319	0.00531
6	ACCT 303-MISC. INTANGIBLE PLANT	PLT303	0.76975	0.04296	0.11218	0.00319	0.00531
7	ACCT 365-LAND & LAND RIGHTS	PLT365	0.51937	0.02705	0.20415	0.00910	0.01765
8	ACCT 366-STRUCTURES & IMPROV.	PLT366	0.51937	0.02705	0.20415	0.00910	0.01765
9	ACCT 367-MAINS	PLT367	0.51937	0.02705	0.20415	0.00910	0.01765
10	ACCT 369-MEAS. & REG STATION EQ	PLT369	0.51937	0.02705	0.20415	0.00910	0.01765
11	ACCT 371-OTHER TRANS EQUIP	PLT371	0.51937	0.02705	0.20415	0.00910	0.01765
12	TOTAL TRANSMISSION PLANT	TRANPLT	0.51937	0.02705	0.20415	0.00910	0.01765
13	ACCT 374-DISTR LAND & LAND RIGHTS	PLT374	0.51937	0.02705	0.20415	0.00910	0.01765
14	ACCT 375-STRUCTURES & IMPROV	PLT375	0.51937	0.02705	0.20415	0.00910	0.01765
15	ACCT 376-MAINS	PLT376	0.51937	0.02705	0.20415	0.00910	0.01765
16	ACCT 378-MEAS & REG EQ - GEN	PLT378	0.51937	0.02705	0.20415	0.00910	0.01765
17	ACCT 379-MEAS & REG EQ - CITY GATE	PLT379	0.51937	0.02705	0.20415	0.00910	0.01765
18	ACCT 380-SERVICES	PLT380	0.86442	0.04896	0.07876	0.00018	0.00000
19	ACCT 381-METERS	PLT381	0.85744	0.04856	0.07812	0.00220	0.00173
20	ACCT 382-METER INSTALLATIONS	PLT382	0.85744	0.04856	0.07812	0.00220	0.00173
21	ACCT 383-REGULATORS	PLT383	0.87127	0.04934	0.07938	0.00000	0.00000
22	ACCT 384-REGULATOR INSTALLATIONS	PLT384	0.87127	0.04934	0.07938	0.00000	0.00000
23	ACCT 385-INDUSTRIAL MEAS. EQUIP	PLT385	0.00000	0.00000	0.00000	0.17949	0.14103
24	ACCT 387-OTHER EQUIPMENT	PLT387	0.51937	0.02705	0.20415	0.00910	0.01765
25	ACCT 389-GEN PLT LAND	PLT389	0.76975	0.04296	0.11218	0.00319	0.00531
26	ACCT 390-STRUCTURES & IMPROVE	PLT390	0.76975	0.04296	0.11218	0.00319	0.00531
27	ACCT 391-OFFICE FURN & EQUIP	PLT391	0.76975	0.04296	0.11218	0.00319	0.00531
28	ACCT 392-TRANSPORTATION EQUIP	PLT392	0.76975	0.04296	0.11218	0.00319	0.00531
29	ACCT 393-STORES EQUIPMENT	PLT393	0.76975	0.04296	0.11218	0.00319	0.00531
30	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	0.76975	0.04296	0.11218	0.00319	0.00531
31	ACCT 395-LABORATORY EQUIPMENT	PLT395	0.76975	0.04296	0.11218	0.00319	0.00531
32	ACCT 396-POWER OPER EQUIP	PLT396	0.76975	0.04296	0.11218	0.00319	0.00531
33	ACCT 397-COMMUNICATION EQUIP	PLT397	0.76975	0.04296	0.11218	0.00319	0.00531
34	ACCT 398-MISCELLANEOUS EQUIP	PLT398	0.76975	0.04296	0.11218	0.00319	0.00531
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	0.00000	0.00000	0.00000	0.00000	0.00000
36	ACCT 367 & 376 TOTAL MAINS	PLT367376	0.51937	0.02705	0.20415	0.00910	0.01765
37	ACCT 376 MAINS + 380 SERVICES	PLT376380	0.64493	0.03502	0.15852	0.00586	0.01123
38	TOTAL DISTRIBUTION PLANT	DISTRPLT	0.65975	0.03600	0.15084	0.00645	0.01110
39							
40	ACCT 378 & 379 MEAS. & REG. EQUIP	PLT37879	0.51937	0.02705	0.20415	0.00910	0.01765
41	ACCT 382 & 384 INSTALLATIONS	PLT38284	0.85936	0.04867	0.07830	0.00189	0.00149
42							
43							
44							
45							

UNS GAS COMPANY
COST OF SERVICE STUDY
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		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	INTERNALLY DEVELOPED RATIOS				
2					
3	TOTAL GAS PLANT IN SERVICE	PLANT	0.00359	0.00467	0.07166
4	SUM OF ALLOCATED LABOR EXP	LABOR	0.00118	0.00225	0.03340
5	ACCT 302-FRANCHISE & CONSENTS	PLT302	0.00118	0.00225	0.03340
6	ACCT 303-MISC. INTANGIBLE PLANT	PLT303	0.00118	0.00225	0.03340
7	ACCT 365-LAND & LAND RIGHTS	PLT365	0.00405	0.00738	0.12158
8	ACCT 366-STRUCTURES & IMPROV.	PLT366	0.00405	0.00738	0.12158
9	ACCT 367-MAINS	PLT367	0.00405	0.00738	0.12158
10	ACCT 369-MEAS. & REG STATION EQ	PLT369	0.00405	0.00738	0.12158
11	ACCT 371-OTHER TRANS EQUIP	PLT371	0.00405	0.00738	0.12158
12	TOTAL TRANSMISSION PLANT	TRANPLT	0.00405	0.00738	0.12158
13	ACCT 374-DISTR LAND & LAND RIGHTS	PLT374	0.00405	0.00738	0.12158
14	ACCT 375-STRUCTURES & IMPROV	PLT375	0.00405	0.00738	0.12158
15	ACCT 376-MAINS	PLT376	0.00405	0.00738	0.12158
16	ACCT 378-MEAS & REG EQ - GEN	PLT378	0.00405	0.00738	0.12158
17	ACCT 379-MEAS & REG EQ - CITY GATE	PLT379	0.00405	0.00738	0.12158
18	ACCT 380-SERVICES	PLT380	0.00014	0.00006	0.00000
19	ACCT 381-METERS	PLT381	0.00014	0.00078	0.00235
20	ACCT 382-METER INSTALLATIONS	PLT382	0.00014	0.00078	0.00235
21	ACCT 383-REGULATORS	PLT383	0.00000	0.00000	0.00000
22	ACCT 384-REGULATOR INSTALLATIONS	PLT384	0.00000	0.00000	0.00000
23	ACCT 385-INDUSTRIAL MEAS. EQUIP	PLT385	0.25641	0.06410	0.19231
24	ACCT 387-OTHER EQUIPMENT	PLT387	0.00405	0.00738	0.12158
25	ACCT 389-GEN PLT LAND	PLT389	0.00118	0.00225	0.03340
26	ACCT 390-STRUCTURES & IMPROVE	PLT390	0.00118	0.00225	0.03340
27	ACCT 391-OFFICE FURN & EQUIP	PLT391	0.00118	0.00225	0.03340
28	ACCT 392-TRANSPORTATION EQUIP	PLT392	0.00118	0.00225	0.03340
29	ACCT 393-STORES EQUIPMENT	PLT393	0.00118	0.00225	0.03340
30	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	0.00118	0.00225	0.03340
31	ACCT 395-LABORATORY EQUIPMENT	PLT395	0.00118	0.00225	0.03340
32	ACCT 396-POWER OPER EQUIP	PLT396	0.00118	0.00225	0.03340
33	ACCT 397-COMMUNICATION EQUIP	PLT397	0.00118	0.00225	0.03340
34	ACCT 398-MISCELLANEOUS EQUIP	PLT398	0.00118	0.00225	0.03340
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	0.00000	0.00000	0.00000
36	ACCT 367 & 376 TOTAL MAINS	PLT367376	0.00405	0.00738	0.12158
37	ACCT 376 MAINS + 380 SERVICES	PLT376380	0.00262	0.00472	0.07734
38	TOTAL DISTRIBUTION PLANT	DISTRPLT	0.00375	0.00470	0.07155
39					
40	ACCT 378 & 379 MEAS. & REG. EQUIP	PLT37879	0.00405	0.00738	0.12158
41	ACCT 382 & 384 INSTALLATIONS	PLT38284	0.00012	0.00068	0.00203
42					
43					
44					
45					

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
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		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	INTERNALLY DEVELOPED RATIOS						
2	----------						
3	TOTAL GAS PLANT IN SERVICE	PLANT	0.02838	0.00534	0.02142	0.00050	0.00027
4	SUM OF ALLOCATED LABOR EXP	LABOR	0.01692	0.00235	0.01014	0.00023	0.00014
5	ACCT 302-FRANCHISE & CONSENTS	PLT302	0.01692	0.00235	0.01014	0.00023	0.00014
6	ACCT 303-MISC. INTANGIBLE PLANT	PLT303	0.01692	0.00235	0.01014	0.00023	0.00014
7	ACCT 365-LAND & LAND RIGHTS	PLT365	0.04382	0.00866	0.03588	0.00085	0.00045
8	ACCT 366-STRUCTURES & IMPROV.	PLT366	0.04382	0.00866	0.03588	0.00085	0.00045
9	ACCT 367-MAINS	PLT367	0.04382	0.00866	0.03588	0.00085	0.00045
10	ACCT 369-MEAS. & REG STATION EQ	PLT369	0.04382	0.00866	0.03588	0.00085	0.00045
11	ACCT 371-OTHER TRANS EQUIP	PLT371	0.04382	0.00866	0.03588	0.00085	0.00045
12	TOTAL TRANSMISSION PLANT	TRANPLT	0.04382	0.00866	0.03588	0.00085	0.00045
13	ACCT 374-DISTR LAND & LAND RIGHTS	PLT374	0.04382	0.00866	0.03588	0.00085	0.00045
14	ACCT 375-STRUCTURES & IMPROV	PLT375	0.04382	0.00866	0.03588	0.00085	0.00045
15	ACCT 376-MAINS	PLT376	0.04382	0.00866	0.03588	0.00085	0.00045
16	ACCT 378-MEAS & REG EQ - GEN	PLT378	0.04382	0.00866	0.03588	0.00085	0.00045
17	ACCT 379-MEAS & REG EQ - CITY GATE	PLT379	0.04382	0.00866	0.03588	0.00085	0.00045
18	ACCT 380-SERVICES	PLT380	0.00741	0.00003	0.00000	0.00000	0.00003
19	ACCT 381-METERS	PLT381	0.00735	0.00003	0.00125	0.00000	0.00003
20	ACCT 382-METER INSTALLATIONS	PLT382	0.00735	0.00003	0.00125	0.00000	0.00003
21	ACCT 383-REGULATORS	PLT383	0.00000	0.00000	0.00000	0.00000	0.00000
22	ACCT 384-REGULATOR INSTALLATIONS	PLT384	0.00000	0.00000	0.00000	0.00000	0.00000
23	ACCT 385-INDUSTRIAL MEAS. EQUIP	PLT385	0.00000	0.06410	0.10256	0.00000	0.00000
24	ACCT 387-OTHER EQUIPMENT	PLT387	0.04382	0.00866	0.03588	0.00085	0.00045
25	ACCT 389-GEN PLT LAND	PLT389	0.01692	0.00235	0.01014	0.00023	0.00014
26	ACCT 390-STRUCTURES & IMPROVE	PLT390	0.01692	0.00235	0.01014	0.00023	0.00014
27	ACCT 391-OFFICE FURN & EQUIP	PLT391	0.01692	0.00235	0.01014	0.00023	0.00014
28	ACCT 392-TRANSPORTATION EQUIP	PLT392	0.01692	0.00235	0.01014	0.00023	0.00014
29	ACCT 393-STORES EQUIPMENT	PLT393	0.01692	0.00235	0.01014	0.00023	0.00014
30	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	0.01692	0.00235	0.01014	0.00023	0.00014
31	ACCT 395-LABORATORY EQUIPMENT	PLT395	0.01692	0.00235	0.01014	0.00023	0.00014
32	ACCT 396-POWER OPER EQUIP	PLT396	0.01692	0.00235	0.01014	0.00023	0.00014
33	ACCT 397-COMMUNICATION EQUIP	PLT397	0.01692	0.00235	0.01014	0.00023	0.00014
34	ACCT 398-MISCELLANEOUS EQUIP	PLT398	0.01692	0.00235	0.01014	0.00023	0.00014
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	0.00000	0.00000	0.00000	0.00000	0.00000
36	ACCT 367 & 376 TOTAL MAINS	PLT367376	0.04382	0.00866	0.03588	0.00085	0.00045
37	ACCT 376 MAINS + 380 SERVICES	PLT376380	0.03057	0.00552	0.02282	0.00054	0.00030
38	TOTAL DISTRIBUTION PLANT	DISTRPLT	0.02832	0.00536	0.02140	0.00049	0.00027
39							
40	ACCT 378 & 379 MEAS. & REG. EQUIP	PLT37879	0.04382	0.00866	0.03588	0.00085	0.00045
41	ACCT 382 & 384 INSTALLATIONS	PLT38284	0.00633	0.00003	0.00108	0.00000	0.00003
42							
43							
44							
45							

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	INTERNALLY DEVELOPED RATIOS CONT.								
2	---								
3	TOTAL GAS COSTS	GASCOSTS	1.00000	0.61246	0.26201	0.01511	0.05405	0.01020	0.04617
4	ACCT 421-PURCHASED POWER EXPENSE	EXP421	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
4	ACCT 805-PURCHASED GAS EXPENSE	EXP805	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
6	ACCT 807-PUR GAS DEMAND	EXP807D	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
7	ACCT 807-PUR GAS COMMODITY	EXP807C	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
8									
9									
10	ACCT 856-MAIN EXPENSE	EXP856	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
11	ACCT 857-MEAS AND REG STATION	EXP857	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
12	ACCT 864-MAINT OF STATION EQUIP	EXP864	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
13	ACCT 867-MAINT OF OTHER EQUIP	EXP867	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
14	ACCT 871-LOAD DISPATCHING	EXP871	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
15	ACCT 874-MAINS & SERVICING EXP	EXP874	1.00000	0.67996	0.17560	0.08468	0.05892	0.00054	0.00030
16	ACCT 875-MEAS AND REG STATION	EXP875	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
17	ACCT 876-MEAS AND REG STATION	EXP876	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
18	ACCT 877-MEAS AND REG STATION	EXP877	1.00000	0.92062	0.07938	0.00000	0.00000	0.00000	0.00000
19	ACCT 878-METER EXPENSE	EXP878	1.00000	0.90600	0.08204	0.00327	0.00864	0.00000	0.00003
20	ACCT 879-CUST INSTALL EXPENSE	EXP879	1.00000	0.90803	0.08167	0.00282	0.00745	0.00000	0.00003
21	ACCT 880-OTHER DISTR EXP	EXP880	1.00000	0.78975	0.13027	0.04523	0.03430	0.00028	0.00017
22	ACCT 881-RENTS	EXP881	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
23	ACCT 886-MAINT OF STRUCTURES	EXP886	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
24	ACCT 887-MAINT OF MAINS	EXP887	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
25	ACCT 889-MAINT OF MEAS/REG	EXP889	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
26	ACCT 890-MAINT OF MEAS/REG	EXP890	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
27	ACCT 891-MAINT OF MEAS/REG	EXP891	1.00000	0.92062	0.07938	0.00000	0.00000	0.00000	0.00000
28	ACCT 892-MAINT OF SERVICES	EXP892	1.00000	0.91338	0.07894	0.00020	0.00745	0.00000	0.00003
29	ACCT 893-MAINT OF METER	EXP893	1.00000	0.90600	0.08204	0.00327	0.00864	0.00000	0.00003
30	ACCT 894-MAINT OF OTHER EQUIP	EXP894	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
31	ACCT 902-METER READING EXP	EXP902	1.00000	0.91305	0.07898	0.00038	0.00756	0.00000	0.00003
32	ACCT 903-CUST RECORDS & COLLEC	EXP903	1.00000	0.91326	0.07892	0.00028	0.00750	0.00000	0.00003
33	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	1.00000	0.57549	0.15806	0.20434	0.06163	0.00000	0.00049
34	ACCT 905-MISC CUST ACCT EXP	EXP905	1.00000	0.87225	0.08853	0.02505	0.01408	0.00000	0.00009
35	ACCT 906-CUST SERVICE & INFO	EXP906	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
36	ACCT 908-CUSTOMER ASSISTANCE	EXP908	1.00000	0.91330	0.07891	0.00026	0.00744	0.00003	0.00006
37	ACCT 909-INFO & INSTRUCT ADV	EXP909	1.00000	0.91330	0.07891	0.00026	0.00744	0.00003	0.00006
38	ACCT 910-MISC SERV & INFO	EXP910	1.00000	0.91330	0.07891	0.00026	0.00744	0.00003	0.00006
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	INTERNALLY DEVELOPED RATIOS CONT.							
2								
3	TOTAL GAS COSTS	GASCOSTS	0.25056	0.01145	0.00474	0.01037	0.04420	0.00985
4	ACCT 421-PURCHASED POWER EXPENSE	EXP421	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
4	ACCT 805-PURCHASED GAS EXPENSE	EXP805	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
6	ACCT 807-PUR GAS DEMAND	EXP807D	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
7	ACCT 807-PUR GAS COMMODITY	EXP807C	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
8								
9								
10	ACCT 856-MAIN EXPENSE	EXP856	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
11	ACCT 857-MEAS AND REG STATION	EXP857	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
12	ACCT 864-MAINT OF STATION EQUIP	EXP864	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
13	ACCT 867-MAINT OF OTHER EQUIP	EXP867	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
14	ACCT 871-LOAD DISPATCHING	EXP871	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
15	ACCT 874-MAINS & SERVICING EXP	EXP874	0.15852	0.01708	0.00262	0.08206	0.03057	0.02835
16	ACCT 875-MEAS AND REG STATION	EXP875	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
17	ACCT 876-MEAS AND REG STATION	EXP876	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
18	ACCT 877-MEAS AND REG STATION	EXP877	0.07938	0.00000	0.00000	0.00000	0.00000	0.00000
19	ACCT 878-METER EXPENSE	EXP878	0.07812	0.00392	0.00014	0.00314	0.00735	0.00129
20	ACCT 879-CUST INSTALL EXPENSE	EXP879	0.07830	0.00338	0.00012	0.00270	0.00633	0.00111
21	ACCT 880-OTHER DISTR EXP	EXP880	0.11950	0.01078	0.00141	0.04382	0.01906	0.01524
22	ACCT 881-RENTS	EXP881	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
23	ACCT 886-MAINT OF STRUCTURES	EXP886	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
24	ACCT 887-MAINT OF MAINS	EXP887	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
25	ACCT 889-MAINT OF MEAS/REG	EXP889	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
26	ACCT 890-MAINT OF MEAS/REG	EXP890	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
27	ACCT 891-MAINT OF MEAS/REG	EXP891	0.07938	0.00000	0.00000	0.00000	0.00000	0.00000
28	ACCT 892-MAINT OF SERVICES	EXP892	0.07876	0.00018	0.00014	0.00006	0.00741	0.00003
29	ACCT 893-MAINT OF METER	EXP893	0.07812	0.00392	0.00014	0.00314	0.00735	0.00129
30	ACCT 894-MAINT OF OTHER EQUIP	EXP894	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
31	ACCT 902-METER READING EXP	EXP902	0.07873	0.00025	0.00014	0.00024	0.00741	0.00015
32	ACCT 903-CUST RECORDS & COLLEC	EXP903	0.07875	0.00017	0.00014	0.00014	0.00741	0.00009
33	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	0.12142	0.03664	0.00018	0.20415	0.00000	0.06163
34	ACCT 905-MISC CUST ACCT EXP	EXP905	0.08392	0.00461	0.00014	0.02491	0.00651	0.00757
35	ACCT 906-CUST SERVICE & INFO	EXP906	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
36	ACCT 908-CUSTOMER ASSISTANCE	EXP908	0.07875	0.00016	0.00014	0.00012	0.00002	0.00742
37	ACCT 909-INFO & INSTRUCT ADV	EXP909	0.07875	0.00016	0.00014	0.00012	0.00002	0.00742
38	ACCT 910-MISC SERV & INFO	EXP910	0.07875	0.00016	0.00014	0.00012	0.00002	0.00742
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
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		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	INTERNALLY DEVELOPED RATIOS CONT.						
2	---						
3	TOTAL GAS COSTS	GASCOSTS	0.58224	0.03022	0.25056	0.01145	0.00000
4	ACCT 421-PURCHASED POWER EXPENSE	EXP421	0.00000	0.00000	0.00000	0.00000	0.00000
4	ACCT 805-PURCHASED GAS EXPENSE	EXP805	0.00000	0.00000	0.00000	0.00000	0.00000
6	ACCT 807-PUR GAS DEMAND	EXP807D	0.00000	0.00000	0.00000	0.00000	0.00000
7	ACCT 807-PUR GAS COMMODITY	EXP807C	0.00000	0.00000	0.00000	0.00000	0.00000
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10	ACCT 856-MAIN EXPENSE	EXP856	0.51937	0.02705	0.20415	0.00910	0.01765
11	ACCT 857-MEAS AND REG STATION	EXP857	0.00000	0.00000	0.00000	0.00000	0.00000
12	ACCT 864-MAINT OF STATION EQUIP	EXP864	0.00000	0.00000	0.00000	0.00000	0.00000
13	ACCT 867-MAINT OF OTHER EQUIP	EXP867	0.51937	0.02705	0.20415	0.00910	0.01765
14	ACCT 871-LOAD DISPATCHING	EXP871	0.00000	0.00000	0.00000	0.00000	0.00000
15	ACCT 874-MAINS & SERVICING EXP	EXP874	0.64493	0.03502	0.15852	0.00586	0.01123
16	ACCT 875-MEAS AND REG STATION	EXP875	0.51937	0.02705	0.20415	0.00910	0.01765
17	ACCT 876-MEAS AND REG STATION	EXP876	0.51937	0.02705	0.20415	0.00910	0.01765
18	ACCT 877-MEAS AND REG STATION	EXP877	0.87127	0.04934	0.07938	0.00000	0.00000
19	ACCT 878-METER EXPENSE	EXP878	0.85744	0.04856	0.07812	0.00220	0.00173
20	ACCT 879-CUST INSTALL EXPENSE	EXP879	0.85936	0.04867	0.07830	0.00189	0.00149
21	ACCT 880-OTHER DISTR EXP	EXP880	0.74815	0.04160	0.11950	0.00412	0.00665
22	ACCT 881-RENTS	EXP881	0.51937	0.02705	0.20415	0.00910	0.01765
23	ACCT 886-MAINT OF STRUCTURES	EXP886	0.51937	0.02705	0.20415	0.00910	0.01765
24	ACCT 887-MAINT OF MAINS	EXP887	0.51937	0.02705	0.20415	0.00910	0.01765
25	ACCT 889-MAINT OF MEAS/REG	EXP889	0.51937	0.02705	0.20415	0.00910	0.01765
26	ACCT 890-MAINT OF MEAS/REG	EXP890	0.51937	0.02705	0.20415	0.00910	0.01765
27	ACCT 891-MAINT OF MEAS/REG	EXP891	0.87127	0.04934	0.07938	0.00000	0.00000
28	ACCT 892-MAINT OF SERVICES	EXP892	0.86442	0.04896	0.07876	0.00018	0.00000
29	ACCT 893-MAINT OF METER	EXP893	0.85744	0.04856	0.07812	0.00220	0.00173
30	ACCT 894-MAINT OF OTHER EQUIP	EXP894	0.51937	0.02705	0.20415	0.00910	0.01765
31	ACCT 902-METER READING EXP	EXP902	0.86411	0.04894	0.07873	0.00010	0.00015
32	ACCT 903-CUST RECORDS & COLLEC	EXP903	0.86431	0.04895	0.07875	0.00010	0.00008
33	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	0.54597	0.02952	0.12142	0.00442	0.03222
34	ACCT 905-MISC CUST ACCT EXP	EXP905	0.82566	0.04659	0.08392	0.00062	0.00399
35	ACCT 906-CUST SERVICE & INFO	EXP906	0.00000	0.00000	0.00000	0.00000	0.00000
36	ACCT 908-CUSTOMER ASSISTANCE	EXP908	0.86434	0.04895	0.07875	0.00010	0.00006
37	ACCT 909-INFO & INSTRUCT ADV	EXP909	0.86434	0.04895	0.07875	0.00010	0.00006
38	ACCT 910-MISC SERV & INFO	EXP910	0.86434	0.04895	0.07875	0.00010	0.00006
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	INTERNALLY DEVELOPED RATIOS CONT.				
2					
3	TOTAL GAS COSTS	GASCOSTS	0.00474	0.01037	0.00000
4	ACCT 421-PURCHASED POWER EXPENSE	EXP421	0.00000	0.00000	0.00000
4	ACCT 805-PURCHASED GAS EXPENSE	EXP805	0.00000	0.00000	0.00000
6	ACCT 807-PUR GAS DEMAND	EXP807D	0.00000	0.00000	0.00000
7	ACCT 807-PUR GAS COMMODITY	EXP807C	0.00000	0.00000	0.00000
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10	ACCT 856-MAIN EXPENSE	EXP856	0.00405	0.00738	0.12158
11	ACCT 857-MEAS AND REG STATION	EXP857	0.00000	0.00000	0.00000
12	ACCT 864-MAINT OF STATION EQUIP	EXP864	0.00000	0.00000	0.00000
13	ACCT 867-MAINT OF OTHER EQUIP	EXP867	0.00405	0.00738	0.12158
14	ACCT 871-LOAD DISPATCHING	EXP871	0.00000	0.00000	0.00000
15	ACCT 874-MAINS & SERVICING EXP	EXP874	0.00262	0.00472	0.07734
16	ACCT 875-MEAS AND REG STATION	EXP875	0.00405	0.00738	0.12158
17	ACCT 876-MEAS AND REG STATION	EXP876	0.00405	0.00738	0.12158
18	ACCT 877-MEAS AND REG STATION	EXP877	0.00000	0.00000	0.00000
19	ACCT 878-METER EXPENSE	EXP878	0.00014	0.00078	0.00235
20	ACCT 879-CUST INSTALL EXPENSE	EXP879	0.00012	0.00068	0.00203
21	ACCT 880-OTHER DISTR EXP	EXP880	0.00141	0.00282	0.04099
22	ACCT 881-RENTS	EXP881	0.00405	0.00738	0.12158
23	ACCT 886-MAINT OF STRUCTURES	EXP886	0.00405	0.00738	0.12158
24	ACCT 887-MAINT OF MAINS	EXP887	0.00405	0.00738	0.12158
25	ACCT 889-MAINT OF MEAS/REG	EXP889	0.00405	0.00738	0.12158
26	ACCT 890-MAINT OF MEAS/REG	EXP890	0.00405	0.00738	0.12158
27	ACCT 891-MAINT OF MEAS/REG	EXP891	0.00000	0.00000	0.00000
28	ACCT 892-MAINT OF SERVICES	EXP892	0.00014	0.00006	0.00000
29	ACCT 893-MAINT OF METER	EXP893	0.00014	0.00078	0.00235
30	ACCT 894-MAINT OF OTHER EQUIP	EXP894	0.00405	0.00738	0.12158
31	ACCT 902-METER READING EXP	EXP902	0.00014	0.00003	0.00021
32	ACCT 903-CUST RECORDS & COLLEC	EXP903	0.00014	0.00003	0.00010
33	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	0.00018	0.00027	0.20388
34	ACCT 905-MISC CUST ACCT EXP	EXP905	0.00014	0.00006	0.02484
35	ACCT 906-CUST SERVICE & INFO	EXP906	0.00000	0.00000	0.00000
36	ACCT 908-CUSTOMER ASSISTANCE	EXP908	0.00014	0.00003	0.00009
37	ACCT 909-INFO & INSTRUCT ADV	EXP909	0.00014	0.00003	0.00009
38	ACCT 910-MISC SERV & INFO	EXP910	0.00014	0.00003	0.00009
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	INTERNALLY DEVELOPED RATIOS CONT.						
2	---						
3	TOTAL GAS COSTS	GASCOSTS	0.04420	0.00985	0.00000	0.01020	0.04617
4	ACCT 421-PURCHASED POWER EXPENSE	EXP421	0.00000	0.00000	0.00000	0.00000	0.00000
4	ACCT 805-PURCHASED GAS EXPENSE	EXP805	0.00000	0.00000	0.00000	0.00000	0.00000
6	ACCT 807-PUR GAS DEMAND	EXP807D	0.00000	0.00000	0.00000	0.00000	0.00000
7	ACCT 807-PUR GAS COMMODITY	EXP807C	0.00000	0.00000	0.00000	0.00000	0.00000
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9							
10	ACCT 856-MAIN EXPENSE	EXP856	0.04382	0.00866	0.03588	0.00085	0.00045
11	ACCT 857-MEAS AND REG STATION	EXP857	0.00000	0.00000	0.00000	0.00000	0.00000
12	ACCT 864-MAINT OF STATION EQUIP	EXP864	0.00000	0.00000	0.00000	0.00000	0.00000
13	ACCT 867-MAINT OF OTHER EQUIP	EXP867	0.04382	0.00866	0.03588	0.00085	0.00045
14	ACCT 871-LOAD DISPATCHING	EXP871	0.00000	0.00000	0.00000	0.00000	0.00000
15	ACCT 874-MAINS & SERVICING EXP	EXP874	0.03057	0.00552	0.02282	0.00054	0.00030
16	ACCT 875-MEAS AND REG STATION	EXP875	0.04382	0.00866	0.03588	0.00085	0.00045
17	ACCT 876-MEAS AND REG STATION	EXP876	0.04382	0.00866	0.03588	0.00085	0.00045
18	ACCT 877-MEAS AND REG STATION	EXP877	0.00000	0.00000	0.00000	0.00000	0.00000
19	ACCT 878-METER EXPENSE	EXP878	0.00735	0.00003	0.00125	0.00000	0.00003
20	ACCT 879-CUST INSTALL EXPENSE	EXP879	0.00633	0.00003	0.00108	0.00000	0.00003
21	ACCT 880-OTHER DISTR EXP	EXP880	0.01906	0.00286	0.01238	0.00028	0.00017
22	ACCT 881-RENTS	EXP881	0.04382	0.00866	0.03588	0.00085	0.00045
23	ACCT 886-MAINT OF STRUCTURES	EXP886	0.04382	0.00866	0.03588	0.00085	0.00045
24	ACCT 887-MAINT OF MAINS	EXP887	0.04382	0.00866	0.03588	0.00085	0.00045
25	ACCT 889-MAINT OF MEAS/REG	EXP889	0.04382	0.00866	0.03588	0.00085	0.00045
26	ACCT 890-MAINT OF MEAS/REG	EXP890	0.04382	0.00866	0.03588	0.00085	0.00045
27	ACCT 891-MAINT OF MEAS/REG	EXP891	0.00000	0.00000	0.00000	0.00000	0.00000
28	ACCT 892-MAINT OF SERVICES	EXP892	0.00741	0.00003	0.00000	0.00000	0.00003
29	ACCT 893-MAINT OF METER	EXP893	0.00735	0.00003	0.00125	0.00000	0.00003
30	ACCT 894-MAINT OF OTHER EQUIP	EXP894	0.04382	0.00866	0.03588	0.00085	0.00045
31	ACCT 902-METER READING EXP	EXP902	0.00741	0.00003	0.00011	0.00000	0.00003
32	ACCT 903-CUST RECORDS & COLLEC	EXP903	0.00741	0.00003	0.00006	0.00000	0.00003
33	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	0.00000	0.00000	0.06163	0.00000	0.00049
34	ACCT 905-MISC CUST ACCT EXP	EXP905	0.00651	0.00003	0.00753	0.00000	0.00009
35	ACCT 906-CUST SERVICE & INFO	EXP906	0.00000	0.00000	0.00000	0.00000	0.00000
36	ACCT 908-CUSTOMER ASSISTANCE	EXP908	0.00002	0.00001	0.00741	0.00003	0.00006
37	ACCT 909-INFO & INSTRUCT ADV	EXP909	0.00002	0.00001	0.00741	0.00003	0.00006
38	ACCT 910-MISC SERV & INFO	EXP910	0.00002	0.00001	0.00741	0.00003	0.00006
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	INTERNALLY DEVELOPED RATIOS CONT.								
2	----------								
3	ACCT 912-DEMO & SELLING	EXP912	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
4	ACCT 913-ADVERTISING EXP	EXP913	1.00000	0.91376	0.07879	0.00000	0.00745	0.00000	0.00000
5	ACCT 920-ADMIN & GENERAL SALARY	EXP920	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
6	ACCT 921-OFFICE SUPPIES & EXP	EXP921	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
7	ACCT 923-OUTSIDE SERVICES	EXP923	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
8	ACCT 924-PROPERTY INSURANCE	EXP924	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
9	ACCT 925-INJURIES & DAMAGES	EXP925	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
10	ACCT 926-EMPLOYEE PENSION & BENF	EXP926	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
11	ACCT 928-REG COMMISSION EXP	EXP928	1.00000	0.71654	0.19844	0.03646	0.04661	0.00128	0.00068
12	ACCT 930-MISC GEN EXP	EXP930	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
13	ACCT 931-RENTS	EXP931	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
14	ACCT 932-MAINT OF GENERAL PLT	EXP932	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
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17	LABOR ACCT 820-867	LABTM	1.00000	0.54642	0.23090	0.13301	0.08837	0.00085	0.00045
18	LABOR ACCT 871-881	LABDO	1.00000	0.79562	0.12785	0.04312	0.03299	0.00027	0.00016
19	LABOR ACCT 874-881 & 886-894	LABDM	1.00000	0.72203	0.15819	0.06950	0.04959	0.00044	0.00025
20	LAROR ACCT 902-906	LABCA	1.00000	0.91313	0.07896	0.00035	0.00753	0.00000	0.00003
21	LABOR ACCT 908-910	LABCS	1.00000	0.91330	0.07891	0.00026	0.00744	0.00003	0.00006
22									
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25	ACCTS 902-904	EXP9024	1.00000	0.87225	0.08853	0.02505	0.01408	0.00000	0.00009
26	ACCTS 874 - 879	EXP87479	1.00000	0.78975	0.13027	0.04523	0.03430	0.00028	0.00017
27	ACCTS 908 & 909	EXP9089	1.00000	0.91330	0.07891	0.00026	0.00744	0.00003	0.00006
28	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	1.00000	0.73471	0.15360	0.06471	0.04626	0.00045	0.00027
29	TOTAL GENERAL PLANT	GENPLT	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
30	WORKING CASH 1/8 OF O&M	WCOM	1.00000	0.79548	0.13102	0.04013	0.03196	0.00048	0.00094
31	PRESENT REVENUE	TOTREV	1.00000	0.71654	0.19844	0.03646	0.04661	0.00128	0.00068
32	PAYROLL EXCLUDING A&G	PAYXAG	1.00000	0.81271	0.12069	0.03683	0.02940	0.00023	0.00014
33	COMMON PLANT	PLTCOMN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
34	CHANGE IN REVENUE @ EQUALIZED	REVCHGC	1.00000	0.85664	-0.10484	0.21259	0.03933	-0.00377	0.00005
35	CHANGE IN REVENUE @ PROPOSED	REVCHGP	1.00000	0.70407	0.20821	0.03671	0.04898	0.00135	0.00068
36	NET PLANT - RESIDENTIAL ONLY	RESNTPT	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
37	CAPITALIZED LABOR EXCL ACCT 371	CAPLABX	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
38	WORKING CASH - GAS COSTS	WCGC	1.00000	0.61246	0.26201	0.01511	0.05405	0.01020	0.04617
39	WORKING CASH - OTHER	WCOTH	1.00000	0.79842	0.12891	0.04053	0.03160	0.00033	0.00021
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			COMMERCIAL		INDUSTRIAL		PUBLIC AUTHORITY	
		ALLOC	SM. VOL. (8)	LG. VOL. (9)	SM. VOL. (10)	LG. VOL. (11)	SM. VOL. (12)	LG. VOL. (13)
1	INTERNALLY DEVELOPED RATIOS CONT.							
2	----------							
3	ACCT 912-DEMO & SELLING	EXP912	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
4	ACCT 913-ADVERTISING EXP	EXP913	0.07879	0.00000	0.00000	0.00000	0.00742	0.00003
5	ACCT 920-ADMIN & GENERAL SALARY	EXP920	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
6	ACCT 921-OFFICE SUPPIES & EXP	EXP921	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
7	ACCT 923-OUTSIDE SERVICES	EXP923	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
8	ACCT 924-PROPERTY INSURANCE	EXP924	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
9	ACCT 925-INJURIES & DAMAGES	EXP925	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
10	ACCT 926-EMPLOYEE PENSION & BENF	EXP926	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
11	ACCT 928-REG COMMISSION EXP	EXP928	0.18352	0.01491	0.00257	0.03390	0.03113	0.01548
12	ACCT 930-MISC GEN EXP	EXP930	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
13	ACCT 931-RENTS	EXP931	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
14	ACCT 932-MAINT OF GENERAL PLT	EXP932	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
15								
16								
17	LABOR ACCT 820-867	LABTM	0.20415	0.02675	0.00405	0.12897	0.04382	0.04454
18	LABOR ACCT 871-881	LABDO	0.11744	0.01041	0.00135	0.04177	0.01845	0.01454
19	LABOR ACCT 874-881 & 886-894	LABDM	0.14382	0.01437	0.00217	0.06733	0.02630	0.02328
20	LAROR ACCT 902-906	LABCA	0.07875	0.00021	0.00014	0.00021	0.00741	0.00012
21	LABOR ACCT 908-910	LABCS	0.07875	0.00016	0.00014	0.00012	0.00002	0.00742
22								
23								
24								
25	ACCTS 902-904	EXP9024	0.08392	0.00461	0.00014	0.02491	0.00651	0.00757
26	ACCTS 874 - 879	EXP87479	0.11950	0.01078	0.00141	0.04382	0.01906	0.01524
27	ACCTS 908 & 909	EXP9089	0.07875	0.00016	0.00014	0.00012	0.00002	0.00742
28	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	0.13929	0.01432	0.00246	0.06225	0.02442	0.02184
29	TOTAL GENERAL PLANT	GENPLT	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
30	WORKING CASH 1/8 OF O&M	WCOM	0.12133	0.00969	0.00133	0.03879	0.01817	0.01379
31	PRESENT REVENUE	TOTREV	0.18352	0.01491	0.00257	0.03390	0.03113	0.01548
32	PAYROLL EXCLUDING A&G	PAYXAG	0.11218	0.00851	0.00118	0.03565	0.01692	0.01248
33	COMMON PLANT	PLTCOMN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
34	CHANGE IN REVENUE @ EQUALIZED	REVCHGC	-0.11403	0.00920	0.00173	0.21086	-0.01491	0.05424
35	CHANGE IN REVENUE @ PROPOSED	REVCHGP	0.19252	0.01569	0.00269	0.03402	0.03279	0.01619
36	NET PLANT - RESIDENTIAL ONLY	RESNTPT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
37	CAPITALIZED LABOR EXCL ACCT 371	CAPLABX	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
38	WORKING CASH - GAS COSTS	WCGC	0.25056	0.01145	0.00474	0.01037	0.04420	0.00985
39	WORKING CASH - OTHER	WCOTH	0.11925	0.00966	0.00128	0.03925	0.01775	0.01385
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			RESIDENTIAL		COMMERCIAL		
		ALLOC	RESIDENTIAL SERVICE (14)	CARES (15)	SM. VOL. (16)	LG. VOL. (17)	TRANS-PORTATION (18)
1	INTERNALLY DEVELOPED RATIOS CONT.						
2	----------						
3	ACCT 912-DEMO & SELLING	EXP912	0.00000	0.00000	0.00000	0.00000	0.00000
4	ACCT 913-ADVERTISING EXP	EXP913	0.86478	0.04898	0.07879	0.00000	0.00000
5	ACCT 920-ADMIN & GENERAL SALARY	EXP920	0.76975	0.04296	0.11218	0.00319	0.00531
6	ACCT 921-OFFICE SUPPIES & EXP	EXP921	0.76975	0.04296	0.11218	0.00319	0.00531
7	ACCT 923-OUTSIDE SERVICES	EXP923	0.76975	0.04296	0.11218	0.00319	0.00531
8	ACCT 924-PROPERTY INSURANCE	EXP924	0.76975	0.04296	0.11218	0.00319	0.00531
9	ACCT 925-INJURIES & DAMAGES	EXP925	0.76975	0.04296	0.11218	0.00319	0.00531
10	ACCT 926-EMPLOYEE PENSION & BENF	EXP926	0.76975	0.04296	0.11218	0.00319	0.00531
11	ACCT 928-REG COMMISSION EXP	EXP928	0.68896	0.02757	0.18352	0.00473	0.01018
12	ACCT 930-MISC GEN EXP	EXP930	0.76975	0.04296	0.11218	0.00319	0.00531
13	ACCT 931-RENTS	EXP931	0.76975	0.04296	0.11218	0.00319	0.00531
14	ACCT 932-MAINT OF GENERAL PLT	EXP932	0.76975	0.04296	0.11218	0.00319	0.00531
15							
16							
17	LABOR ACCT 820-867	LABTM	0.51937	0.02705	0.20415	0.00910	0.01765
18	LABOR ACCT 871-881	LABDO	0.75367	0.04195	0.11744	0.00401	0.00640
19	LABOR ACCT 874-881 & 886-894	LABDM	0.68449	0.03754	0.14382	0.00502	0.00935
20	LAROR ACCT 902-906	LABCA	0.86419	0.04894	0.07875	0.00010	0.00011
21	LABOR ACCT 908-910	LABCS	0.86434	0.04895	0.07875	0.00010	0.00006
22							
23							
24							
25	ACCTS 902-904	EXP9024	0.82566	0.04659	0.08392	0.00062	0.00399
26	ACCTS 874 - 879	EXP87479	0.74815	0.04160	0.11950	0.00412	0.00665
27	ACCTS 908 & 909	EXP9089	0.86434	0.04895	0.07875	0.00010	0.00006
28	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	0.69701	0.03770	0.13929	0.00506	0.00926
29	TOTAL GENERAL PLANT	GENPLT	0.76975	0.04296	0.11218	0.00319	0.00531
30	WORKING CASH 1/8 OF O&M	WCOM	0.75455	0.04093	0.12133	0.00338	0.00631
31	PRESENT REVENUE	TOTREV	0.68896	0.02757	0.18352	0.00473	0.01018
32	PAYROLL EXCLUDING A&G	PAYXAG	0.76975	0.04296	0.11218	0.00319	0.00531
33	COMMON PLANT	PLTCOMN	0.00000	0.00000	0.00000	0.00000	0.00000
34	CHANGE IN REVENUE @ EQUALIZED	REVCHGC	0.76116	0.09549	(0.11403)	0.00661	0.00259
35	CHANGE IN REVENUE @ PROPOSED	REVCHGP	0.70407	0.00000	0.19252	0.00484	0.01085
36	NET PLANT - RESIDENTIAL ONLY	RESNTPT	0.94838	0.05162	0.00000	0.00000	0.00000
37	CAPITALIZED LABOR EXCL ACCT 371	CAPLABX	0.00000	0.00000	0.00000	0.00000	0.00000
38	WORKING CASH - GAS COSTS	WCGC	0.58224	0.03022	0.25056	0.01145	0.00000
39	WORKING CASH - OTHER	WCOTH	0.75732	0.04110	0.11925	0.00325	0.00641
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			INDUSTRIAL		
		ALLOC	SM. VOL. (19)	LG. VOL. (20)	TRANS-PORTATION (21)
1	INTERNALLY DEVELOPED RATIOS CONT.				
2	----------				
3	ACCT 912-DEMO & SELLING	EXP912	0.00000	0.00000	0.00000
4	ACCT 913-ADVERTISING EXP	EXP913	0.00000	0.00000	0.00000
5	ACCT 920-ADMIN & GENERAL SALARY	EXP920	0.00118	0.00225	0.03340
6	ACCT 921-OFFICE SUPPIES & EXP	EXP921	0.00118	0.00225	0.03340
7	ACCT 923-OUTSIDE SERVICES	EXP923	0.00118	0.00225	0.03340
8	ACCT 924-PROPERTY INSURANCE	EXP924	0.00118	0.00225	0.03340
9	ACCT 925-INJURIES & DAMAGES	EXP925	0.00118	0.00225	0.03340
10	ACCT 926-EMPLOYEE PENSION & BENF	EXP926	0.00118	0.00225	0.03340
11	ACCT 928-REG COMMISSION EXP	EXP928	0.00257	0.00235	0.03155
12	ACCT 930-MISC GEN EXP	EXP930	0.00118	0.00225	0.03340
13	ACCT 931-RENTS	EXP931	0.00118	0.00225	0.03340
14	ACCT 932-MAINT OF GENERAL PLT	EXP932	0.00118	0.00225	0.03340
15					
16					
17	LABOR ACCT 820-867	LABTM	0.00405	0.00738	0.12158
18	LABOR ACCT 871-881	LABDO	0.00135	0.00272	0.03905
19	LABOR ACCT 874-881 & 886-894	LABDM	0.00217	0.00394	0.06339
20	LAROR ACCT 902-906	LABCA	0.00014	0.00003	0.00018
21	LABOR ACCT 908-910	LABCS	0.00014	0.00003	0.00009
22					
23					
24					
25	ACCTS 902-904	EXP9024	0.00014	0.00006	0.02484
26	ACCTS 874 - 879	EXP87479	0.00141	0.00282	0.04099
27	ACCTS 908 & 909	EXP9089	0.00014	0.00003	0.00009
28	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	0.00246	0.00366	0.05859
29	TOTAL GENERAL PLANT	GENPLT	0.00118	0.00225	0.03340
30	WORKING CASH 1/8 OF O&M	WCOM	0.00133	0.00226	0.03653
31	PRESENT REVENUE	TOTREV	0.00257	0.00235	0.03155
32	PAYROLL EXCLUDING A&G	PAYXAG	0.00118	0.00225	0.03340
33	COMMON PLANT	PLTCOMN	0.00000	0.00000	0.00000
34	CHANGE IN REVENUE @ EQUALIZED	REVCHGC	0.00173	0.01088	0.19998
35	CHANGE IN REVENUE @ PROPOSED	REVCHGP	0.00269	0.00238	0.03164
36	NET PLANT - RESIDENTIAL ONLY	RESNTPT	0.00000	0.00000	0.00000
37	CAPITALIZED LABOR EXCL ACCT 371	CAPLABX	0.00000	0.00000	0.00000
38	WORKING CASH - GAS COSTS	WCGC	0.00474	0.01037	0.00000
39	WORKING CASH - OTHER	WCOTH	0.00128	0.00213	0.03712
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			PUBLIC AUTHORITY				
		ALLOC	SM. VOL. (22)	LG. VOL. (23)	TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	INTERNALLY DEVELOPED RATIOS CONT.						
2	----------						
3	ACCT 912-DEMO & SELLING	EXP912	0.00000	0.00000	0.00000	0.00000	0.00000
4	ACCT 913-ADVERTISING EXP	EXP913	0.00742	0.00003	0.00000	0.00000	0.00000
5	ACCT 920-ADMIN & GENERAL SALARY	EXP920	0.01692	0.00235	0.01014	0.00023	0.00014
6	ACCT 921-OFFICE SUPPIES & EXP	EXP921	0.01692	0.00235	0.01014	0.00023	0.00014
7	ACCT 923-OUTSIDE SERVICES	EXP923	0.01692	0.00235	0.01014	0.00023	0.00014
8	ACCT 924-PROPERTY INSURANCE	EXP924	0.01692	0.00235	0.01014	0.00023	0.00014
9	ACCT 925-INJURIES & DAMAGES	EXP925	0.01692	0.00235	0.01014	0.00023	0.00014
10	ACCT 926-EMPLOYEE PENSION & BENF	EXP926	0.01692	0.00235	0.01014	0.00023	0.00014
11	ACCT 928-REG COMMISSION EXP	EXP928	0.03113	0.00287	0.01261	0.00128	0.00068
12	ACCT 930-MISC GEN EXP	EXP930	0.01692	0.00235	0.01014	0.00023	0.00014
13	ACCT 931-RENTS	EXP931	0.01692	0.00235	0.01014	0.00023	0.00014
14	ACCT 932-MAINT OF GENERAL PLT	EXP932	0.01692	0.00235	0.01014	0.00023	0.00014
15							
16							
17	LABOR ACCT 820-867	LABTM	0.04382	0.00866	0.03588	0.00085	0.00045
18	LABOR ACCT 871-881	LABDO	0.01845	0.00272	0.01182	0.00027	0.00016
19	LABOR ACCT 874-881 & 886-894	LABDM	0.02630	0.00452	0.01877	0.00044	0.00025
20	LAROR ACCT 902-906	LABCA	0.00741	0.00003	0.00009	0.00000	0.00003
21	LABOR ACCT 908-910	LABCS	0.00002	0.00001	0.00741	0.00003	0.00006
22							
23							
24							
25	ACCTS 902-904	EXP9024	0.00651	0.00003	0.00753	0.00000	0.00009
26	ACCTS 874 - 879	EXP87479	0.01906	0.00286	0.01238	0.00028	0.00017
27	ACCTS 908 & 909	EXP9089	0.00002	0.00001	0.00741	0.00003	0.00006
28	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	0.02442	0.00413	0.01771	0.00045	0.00027
29	TOTAL GENERAL PLANT	GENPLT	0.01692	0.00235	0.01014	0.00023	0.00014
30	WORKING CASH 1/8 OF O&M	WCOM	0.01817	0.00240	0.01138	0.00048	0.00094
31	PRESENT REVENUE	TOTREV	0.03113	0.00287	0.01261	0.00128	0.00068
32	PAYROLL EXCLUDING A&G	PAYXAG	0.01692	0.00235	0.01014	0.00023	0.00014
33	COMMON PLANT	PLTCOMN	0.00000	0.00000	0.00000	0.00000	0.00000
34	CHANGE IN REVENUE @ EQUALIZED	REVCHGC	(0.01491)	0.01093	0.04331	(0.00377)	0.00005
35	CHANGE IN REVENUE @ PROPOSED	REVCHGP	0.03279	0.00295	0.01325	0.00135	0.00068
36	NET PLANT - RESIDENTIAL ONLY	RESNTPT	0.00000	0.00000	0.00000	0.00000	0.00000
37	CAPITALIZED LABOR EXCL ACCT 371	CAPLABX	0.00000	0.00000	0.00000	0.00000	0.00000
38	WORKING CASH - GAS COSTS	WCGC	0.04420	0.00985	0.00000	0.01020	0.04617
39	WORKING CASH - OTHER	WCOTH	0.01775	0.00228	0.01157	0.00033	0.00021
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	INTERNALLY DEVELOPED CONT.								
2	---								
3	REVENUES FROM GAS SALES								
4	BASE REVENUES		1.00000	0.71116	0.20234	0.03692	0.04760	0.00131	0.00066
5									
6									
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	INTERNALLY DEVELOPED CONT.							
2	---							
3	REVENUES FROM GAS SALES							
4	BASE REVENUES		0.18710	0.01525	0.00261	0.03431	0.03187	0.01574
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	INTERNALLY DEVELOPED CONT.						
2							
3	REVENUES FROM GAS SALES						
4	BASE REVENUES		0.68423	0.02693	0.18710	0.00482	0.01042
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	INTERNALLY DEVELOPED CONT.				
2	---				
3	REVENUES FROM GAS SALES				
4	BASE REVENUES		0.00261	0.00237	0.03193
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	INTERNALLY DEVELOPED CONT.						
2							
3	REVENUES FROM GAS SALES						
4	BASE REVENUES		0.03187	0.00291	0.01283	0.00131	0.00066
5							
6							
7							
8							
9							
10							
11							
12							
13							
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	RATIO TABLE CONT.								
2									
3	INTERNALLY DEVELOPED								
4	---								
5									
6									
7	DEVELOPMENT OF UNCOLLECTABLE FACTOR								
8	RESIDENTIAL REVENUE	RESREV	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
9	COMMERCIAL REVENUE	COMREV	1.00000	0.00000	0.99611	0.00000	0.00000	0.00000	0.00389
10	INDUSTRIAL REVENUE	INDREV	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
11	TRANSPORTATION REVENUE	TRAREV	1.00000	0.00000	0.10821	0.68480	0.20699	0.00000	0.00000
12									
13	ALLOCATION OF BAD DEBTS								
14	RESIDENTIAL	RESREV							
15	COMMERCIAL	COMREV							
16	INDUSTRIAL	INDREV							
17	TRANSPORTATION	TRAREV							
18	ALLOCATED BAD DEBTS	BADDEBT	1.00000	0.57549	0.15806	0.20434	0.06163	0.00000	0.00049
19									
20									
21									
22									
23									
24									
25									
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44									
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	RATIO TABLE CONT.							
2								
3	INTERNALLY DEVELOPED							
4	----------							
5								
6								
7	DEVELOPMENT OF UNCOLLECTABLE FACTOR							
8	RESIDENTIAL REVENUE	RESREV	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
9	COMMERCIAL REVENUE	COMREV	0.96109	0.03502	0.00000	0.00000	0.00000	0.00000
10	INDUSTRIAL REVENUE	INDREV	0.00000	0.00000	0.40056	0.59944	0.00000	0.00000
11	TRANSPORTATION REVENUE	TRAREV	0.00000	0.10821	0.00000	0.68480	0.00000	0.20699
12								
13	ALLOCATION OF BAD DEBTS							
14	RESIDENTIAL	RESREV						
15	COMMERCIAL	COMREV						
16	INDUSTRIAL	INDREV						
17	TRANSPORTATION	TRAREV						
18	ALLOCATED BAD DEBTS	BADDEBT	0.12142	0.03664	0.00018	0.20415	0.00000	0.06163
19								
20								
21								
22								
23								
24								
25								
26								
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE (14)	CARES (15)	SM. VOL. (16)	LG. VOL. (17)	TRANS-PORTATION (18)
1	RATIO TABLE CONT.						
2							
3	INTERNALLY DEVELOPED						
4							
5							
6							
7	DEVELOPMENT OF UNCOLLECTABLE FACTOR						
8	RESIDENTIAL REVENUE	RESREV	0.94870	0.05130	0.00000	0.00000	0.00000
9	COMMERCIAL REVENUE	COMREV	0.00000	0.00000	0.96109	0.03502	0.00000
10	INDUSTRIAL REVENUE	INDREV	0.00000	0.00000	0.00000	0.00000	0.00000
11	TRANSPORTATION REVENUE	TRAREV	0.00000	0.00000	0.00000	0.00000	0.10821
12							
13	ALLOCATION OF BAD DEBTS						
14	RESIDENTIAL	RESREV					
15	COMMERCIAL	COMREV					
16	INDUSTRIAL	INDREV					
17	TRANSPORTATION	TRAREV					
18	ALLOCATED BAD DEBTS	BADDEBT	0.54597	0.02952	0.12142	0.00442	0.03222
19							
20							
21							
22							
23							
24							
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

			INDUSTRIAL		
		ALLOC	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(19)	(20)	(21)
1	RATIO TABLE CONT.				
2					
3	INTERNALLY DEVELOPED				
4	----------				
5					
6					
7	DEVELOPMENT OF UNCOLLECTABLE FACTOR				
8	RESIDENTIAL REVENUE	RESREV	0.00000	0.00000	0.00000
9	COMMERCIAL REVENUE	COMREV	0.00000	0.00000	0.00000
10	INDUSTRIAL REVENUE	INDREV	0.40056	0.59944	0.00000
11	TRANSPORTATION REVENUE	TRAREV	0.00000	0.00000	0.68480
12					
13	ALLOCATION OF BAD DEBTS				
14	RESIDENTIAL	RESREV			
15	COMMERCIAL	COMREV			
16	INDUSTRIAL	INDREV			
17	TRANSPORTATION	TRAREV			
18	ALLOCATED BAD DEBTS	BADDEBT	0.00018	0.00027	0.20388
19					
20					
21					
22					
23					
24					
25					
26					
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	RATIO TABLE CONT.						
2							
3	INTERNALLY DEVELOPED						
4							
5							
6							
7	DEVELOPMENT OF UNCOLLECTABLE FACTOR						
8	RESIDENTIAL REVENUE	RESREV	0.00000	0.00000	0.00000	0.00000	0.00000
9	COMMERCIAL REVENUE	COMREV	0.00000	0.00000	0.00000	0.00000	0.00389
10	INDUSTRIAL REVENUE	INDREV	0.00000	0.00000	0.00000	0.00000	0.00000
11	TRANSPORTATION REVENUE	TRAREV	0.00000	0.00000	0.20699	0.00000	0.00000
12							
13	ALLOCATION OF BAD DEBTS						
14	RESIDENTIAL	RESREV					
15	COMMERCIAL	COMREV					
16	INDUSTRIAL	INDREV					
17	TRANSPORTATION	TRAREV					
18	ALLOCATED BAD DEBTS	BADDEBT	0.00000	0.00000	0.06163	0.00000	0.00049
19							
20							
21							
22							
23							
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43							
44							
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UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)
1	INTERNALLY DEVELOPED CONT.								
2	----------								
3	487-FORFEITED DISCOUNTS								
4	REVENUE BY CLASS - RANGE NAME DEFINITION								
5	RESIDENTIAL SERVICE	REV487A	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
6									
7	RESIDENTIAL CARES	REV487C	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
8	COMMERCIAL SM. VOL.	REV487D	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
9									
10	COMMERCIAL LG. VOL.	REV487F	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
11	COMMERCIAL TRANSPORTATION	REV487G	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
12	INDUSTRIAL SM. VOL.	REV487H	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
13	INDUSTRIAL LG. VOL.	REV487I	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
14	INDUSTRIAL TRANSPORTATION	REV487J	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
15	PUBLIC AUTHORITY SM. VOL.	REV487K	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
16	PUBLIC AUTHORITY LG. VOL.	REV487L	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
17	PUBLIC AUTHORITY TRANSPORT.	REV487M	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
18	IRRIGATION	REV487N	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
19									
20	487-FORFEITED DISCOUNTS								
21	REVENUE BY CLASS - ALLOCATION								
22	RESIDENTIAL SERVICE	REV487A							
23									
24	RESIDENTIAL CARES	REV487C							
25	COMMERCIAL SM. VOL.	REV487D							
26									
27	COMMERCIAL LG. VOL.	REV487F							
28	COMMERCIAL TRANSPORTATION	REV487G							
29	INDUSTRIAL SM. VOL.	REV487H							
30	INDUSTRIAL LG. VOL.	REV487I							
31	INDUSTRIAL TRANSPORTATION	REV487J							
32	PUBLIC AUTHORITY SM. VOL.	REV487K							
33	PUBLIC AUTHORITY LG. VOL.	REV487L							
34	PUBLIC AUTHORITY TRANSPORT.	REV487M							
35	IRRIGATION	REV487N							
36	TOTAL FOREITED DISCOUNTS	FORFDISC	1.00000	0.74118	0.22107	0.00310	0.03099	0.00000	0.00366
37									
38									
39									
40									
41									
42									

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	COMMERCIAL SM. VOL. (8)	COMMERCIAL LG. VOL. (9)	INDUSTRIAL SM. VOL. (10)	INDUSTRIAL LG. VOL. (11)	PUBLIC AUTHORITY SM. VOL. (12)	PUBLIC AUTHORITY LG. VOL. (13)
1	INTERNALLY DEVELOPED CONT.							
2								
3	487-FORFEITED DISCOUNTS							
4	REVENUE BY CLASS - RANGE NAME DEFINITION							
5	RESIDENTIAL SERVICE	REV487A	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
6								
7	RESIDENTIAL CARES	REV487C	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
8	COMMERCIAL SM. VOL.	REV487D	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
9								
10	COMMERCIAL LG. VOL.	REV487F	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
11	COMMERCIAL TRANSPORTATION	REV487G	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
12	INDUSTRIAL SM. VOL.	REV487H	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
13	INDUSTRIAL LG. VOL.	REV487I	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
14	INDUSTRIAL TRANSPORTATION	REV487J	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
15	PUBLIC AUTHORITY SM. VOL.	REV487K	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
16	PUBLIC AUTHORITY LG. VOL.	REV487L	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
17	PUBLIC AUTHORITY TRANSPORT.	REV487M	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
18	IRRIGATION	REV487N	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
19								
20	487-FORFEITED DISCOUNTS							
21	REVENUE BY CLASS - ALLOCATION							
22	RESIDENTIAL SERVICE	REV487A						
23								
24	RESIDENTIAL CARES	REV487C						
25	COMMERCIAL SM. VOL.	REV487D						
26								
27	COMMERCIAL LG. VOL.	REV487F						
28	COMMERCIAL TRANSPORTATION	REV487G						
29	INDUSTRIAL SM. VOL.	REV487H						
30	INDUSTRIAL LG. VOL.	REV487I						
31	INDUSTRIAL TRANSPORTATION	REV487J						
32	PUBLIC AUTHORITY SM. VOL.	REV487K						
33	PUBLIC AUTHORITY LG. VOL.	REV487L						
34	PUBLIC AUTHORITY TRANSPORT.	REV487M						
35	IRRIGATION	REV487N						
36	TOTAL FOREITED DISCOUNTS	FORFDISC	0.21972	0.00135	0.00142	0.00168	0.03084	0.00014
37								
38								
39								
40								
41								
42								

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	RESIDENTIAL		COMMERCIAL		
			RESIDENTIAL SERVICE	CARES	SM. VOL.	LG. VOL.	TRANS-PORTATION
			(14)	(15)	(16)	(17)	(18)
1	INTERNALLY DEVELOPED CONT.						
2	----------						
3	487-FORFEITED DISCOUNTS						
4	REVENUE BY CLASS - RANGE NAME DEFINITION						
5	RESIDENTIAL SERVICE	REV487A	1.00000	0.00000	0.00000	0.00000	0.00000
6							
7	RESIDENTIAL CARES	REV487C	0.00000	1.00000	0.00000	0.00000	0.00000
8	COMMERCIAL SM. VOL.	REV487D	0.00000	0.00000	1.00000	0.00000	0.00000
9							
10	COMMERCIAL LG. VOL.	REV487F	0.00000	0.00000	0.00000	1.00000	0.00000
11	COMMERCIAL TRANSPORTATION	REV487G	0.00000	0.00000	0.00000	0.00000	1.00000
12	INDUSTRIAL SM. VOL.	REV487H	0.00000	0.00000	0.00000	0.00000	0.00000
13	INDUSTRIAL LG. VOL.	REV487I	0.00000	0.00000	0.00000	0.00000	0.00000
14	INDUSTRIAL TRANSPORTATION	REV487J	0.00000	0.00000	0.00000	0.00000	0.00000
15	PUBLIC AUTHORITY SM. VOL.	REV487K	0.00000	0.00000	0.00000	0.00000	0.00000
16	PUBLIC AUTHORITY LG. VOL.	REV487L	0.00000	0.00000	0.00000	0.00000	0.00000
17	PUBLIC AUTHORITY TRANSPORT.	REV487M	0.00000	0.00000	0.00000	0.00000	0.00000
18	IRRIGATION	REV487N	0.00000	0.00000	0.00000	0.00000	0.00000
19							
20	487-FORFEITED DISCOUNTS						
21	REVENUE BY CLASS - ALLOCATION						
22	RESIDENTIAL SERVICE	REV487A					
23							
24	RESIDENTIAL CARES	REV487C					
25	COMMERCIAL SM. VOL.	REV487D					
26							
27	COMMERCIAL LG. VOL.	REV487F					
28	COMMERCIAL TRANSPORTATION	REV487G					
29	INDUSTRIAL SM. VOL.	REV487H					
30	INDUSTRIAL LG. VOL.	REV487I					
31	INDUSTRIAL TRANSPORTATION	REV487J					
32	PUBLIC AUTHORITY SM. VOL.	REV487K					
33	PUBLIC AUTHORITY LG. VOL.	REV487L					
34	PUBLIC AUTHORITY TRANSPORT.	REV487M					
35	IRRIGATION	REV487N					
36	TOTAL FOREITED DISCOUNTS	FORFDISC	0.70145	0.03973	0.21972	0.00027	0.00108
37							
38							
39							
40							
41							
42							

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	INDUSTRIAL SM. VOL. (19)	INDUSTRIAL LG. VOL. (20)	INDUSTRIAL TRANS-PORTATION (21)
1	INTERNALLY DEVELOPED CONT.				
2	----------				
3	487-FORFEITED DISCOUNTS				
4	REVENUE BY CLASS - RANGE NAME DEFINITION				
5	RESIDENTIAL SERVICE	REV487A	0.00000	0.00000	0.00000
6					
7	RESIDENTIAL CARES	REV487C	0.00000	0.00000	0.00000
8	COMMERCIAL SM. VOL.	REV487D	0.00000	0.00000	0.00000
9					
10	COMMERCIAL LG. VOL.	REV487F	0.00000	0.00000	0.00000
11	COMMERCIAL TRANSPORTATION	REV487G	0.00000	0.00000	0.00000
12	INDUSTRIAL SM. VOL.	REV487H	1.00000	0.00000	0.00000
13	INDUSTRIAL LG. VOL.	REV487I	0.00000	1.00000	0.00000
14	INDUSTRIAL TRANSPORTATION	REV487J	0.00000	0.00000	1.00000
15	PUBLIC AUTHORITY SM. VOL.	REV487K	0.00000	0.00000	0.00000
16	PUBLIC AUTHORITY LG. VOL.	REV487L	0.00000	0.00000	0.00000
17	PUBLIC AUTHORITY TRANSPORT.	REV487M	0.00000	0.00000	0.00000
18	IRRIGATION	REV487N	0.00000	0.00000	0.00000
19					
20	487-FORFEITED DISCOUNTS				
21	REVENUE BY CLASS - ALLOCATION				
22	RESIDENTIAL SERVICE	REV487A			
23					
24	RESIDENTIAL CARES	REV487C			
25	COMMERCIAL SM. VOL.	REV487D			
26					
27	COMMERCIAL LG. VOL.	REV487F			
28	COMMERCIAL TRANSPORTATION	REV487G			
29	INDUSTRIAL SM. VOL.	REV487H			
30	INDUSTRIAL LG. VOL.	REV487I			
31	INDUSTRIAL TRANSPORTATION	REV487J			
32	PUBLIC AUTHORITY SM. VOL.	REV487K			
33	PUBLIC AUTHORITY LG. VOL.	REV487L			
34	PUBLIC AUTHORITY TRANSPORT.	REV487M			
35	IRRIGATION	REV487N			
36	TOTAL FOREITED DISCOUNTS	FORFDISC	0.00142	0.00036	0.00132
37					
38					
39					
40					
41					
42					

UNS GAS COMPANY
COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2008
UNS GAS POSITION-FINAL

		ALLOC	PUBLIC AUTHORITY SM. VOL. (22)	PUBLIC AUTHORITY LG. VOL. (23)	PUBLIC AUTHORITY TRANS-PORTATION (24)	SPECIAL GAS LIGHT SERVICE (25)	IRRIGATION (26)
1	INTERNALLY DEVELOPED CONT.						
2							
3	487-FORFEITED DISCOUNTS						
4	REVENUE BY CLASS - RANGE NAME DEFINITION						
5	RESIDENTIAL SERVICE	REV487A	0.00000	0.00000	0.00000	0.00000	0.00000
6							
7	RESIDENTIAL CARES	REV487C	0.00000	0.00000	0.00000	0.00000	0.00000
8	COMMERCIAL SM. VOL.	REV487D	0.00000	0.00000	0.00000	0.00000	0.00000
9							
10	COMMERCIAL LG. VOL.	REV487F	0.00000	0.00000	0.00000	0.00000	0.00000
11	COMMERCIAL TRANSPORTATION	REV487G	0.00000	0.00000	0.00000	0.00000	0.00000
12	INDUSTRIAL SM. VOL.	REV487H	0.00000	0.00000	0.00000	0.00000	0.00000
13	INDUSTRIAL LG. VOL.	REV487I	0.00000	0.00000	0.00000	0.00000	0.00000
14	INDUSTRIAL TRANSPORTATION	REV487J	0.00000	0.00000	0.00000	0.00000	0.00000
15	PUBLIC AUTHORITY SM. VOL.	REV487K	1.00000	0.00000	0.00000	0.00000	0.00000
16	PUBLIC AUTHORITY LG. VOL.	REV487L	0.00000	1.00000	0.00000	0.00000	0.00000
17	PUBLIC AUTHORITY TRANSPORT.	REV487M	0.00000	0.00000	1.00000	0.00000	0.00000
18	IRRIGATION	REV487N	0.00000	0.00000	0.00000	0.00000	1.00000
19							
20	487-FORFEITED DISCOUNTS						
21	REVENUE BY CLASS - ALLOCATION						
22	RESIDENTIAL SERVICE	REV487A					
23							
24	RESIDENTIAL CARES	REV487C					
25	COMMERCIAL SM. VOL.	REV487D					
26							
27	COMMERCIAL LG. VOL.	REV487F					
28	COMMERCIAL TRANSPORTATION	REV487G					
29	INDUSTRIAL SM. VOL.	REV487H					
30	INDUSTRIAL LG. VOL.	REV487I					
31	INDUSTRIAL TRANSPORTATION	REV487J					
32	PUBLIC AUTHORITY SM. VOL.	REV487K					
33	PUBLIC AUTHORITY LG. VOL.	REV487L					
34	PUBLIC AUTHORITY TRANSPORT.	REV487M					
35	IRRIGATION	REV487N					
36	TOTAL FOREITED DISCOUNTS	FORFDISC	0.03084	0.00014	0.00000	0.00000	0.00366
37							
38							
39							
40							
41							
42							

Schedule H

UNS Gas, Inc.
Summary of Revenues by Customer Classifications
Adjusted Present Rates And Proposed Rates
Test Year Ended June 30, 2008
(Thousands of Dollars)

Line No.	Class of Service	Adjusted Present Net Revenue	Proposed Net Revenue	Proposed Net Increase	Proposed Percent Increase (a)	Line No.
1	Residential Service	$36,381,453	$43,056,622	$6,675,169	18.35%	1
2	Commercial Gas Service	9,818,220	11,689,364	1,871,145	19.06%	2
3	Industrial Gas Service	255,152	303,253	48,101	18.85%	3
4	Public Authority Gas Service	1,779,079	2,117,900	338,821	19.04%	4
5	Special Gas Light Service	66,940	79,706	12,766	19.07%	5
6	Irrigation Service	33,865	40,322	6,458	19.07%	6
7	Transportation Customers	2,823,056	3,351,473	528,417	18.72%	7
8	Subtotal	51,157,764	60,638,641	9,480,876	18.53%	8
9	Other Operating Revenue	1,744,743	1,744,743	0	0.00%	9
10	Total	$52,902,507	$62,383,384	$9,480,876	17.92%	10

Supporting Schedules
(a) H-2 (P2)

Recap Schedules
A-1

UNS Gas, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Year Ended June 30, 2008

Line No.	Class of Service	Rate Schedule Present	Proposed	Actual Therm Sales	Actual Average Number of Customers	Actual Average Therm per Customer	Test Year End Adjustments	Adjusted Therm Sales	Adjusted Average Number of Customers	Adjusted Average Therm per Customer	Line No.
1	Residential Service	R-10	R-10	70,723,037	125,602	563	(2,656,075)	68,066,962	124,959	545	1
2	Residential Service Cares	R-12	R-12	3,478,376	6,745	516	55,060	3,533,436	7,077	499	2
3	Small Volume Commercial Service	C-20	C-20	30,119,256	11,423	2,637	(827,599)	29,291,657	11,385	2,573	3
4	Large Volume Commercial Service	C-22	C-22	1,442,578	15	95,115	(104,334)	1,338,244	14	95,589	4
5	Commercial Transportation	C-22T1	C-22T1	3,344,634	10	321,085	(303,749)	3,040,885	9	337,876	5
6	Small Volume Industrial Service	I-30	I-30	502,579	18	28,448	51,187	553,766	20	27,688	6
7	Large Volume Industrial Service	I-32	I-32	1,246,247	6	219,926	(33,594)	1,212,653	5	242,531	7
8	Industrial Transportation	I-32 T1	I-32 T1	11,443,573	12	973,921	138,953	11,582,526	13	890,964	8
9	Industrial Transportation - Contracts	I-32 T1C	I-32 T1C	7,564,291	3	2,521,430	(2,396,706)	5,167,584	3	1,722,528	
10	T2 Transportation	I-32 T2	I-32 T2	1,151,133	1	1,151,133	0	1,151,133	1	1,151,133	
11	Small Volume Public Authority	P-40	P-40	5,797,679	1,069	5,423	(185,370)	5,612,308	1,072	5,236	11
12	Large Volume Public Authority	P-42	P-42	1,225,072	5	245,014	(32,942)	1,192,130	5	238,426	12
13	Public Authority Transportation	P-42T1	P-42T1	5,127,210	7	715,425	270,621	5,397,831	8	674,729	13
14	Special Gas Light Service	P-44	P-44	145,406	2	72,703	0	145,406	2	72,703	14
15	Irrigation Service	I-60	I-60	104,267	5	20,853	(712)	103,554	5	20,711	15
16	Total Gas Service			143,415,337	144,923	990	(6,025,261)	137,390,076	144,578	950	16

Note: Some transportation customers have more than one meter which is accounted for in this schedule.

UNS Gas, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Year Ended June 30, 2008

Line No.	Class of Service	Actual Net Revenue	Test Year End Adjustments	Adjusted Net Revenue	Proposed Increase $	Proposed Increase %	Proposed Net Revenue	Line No.
1	Residential Service	$35,937,829	($934,080)	$35,003,749	$6,675,169	19.07%	$41,678,918	1
2	Residential Service Cares	1,341,403	$36,302	1,377,705	0	0.00%	1,377,705	2
3	Small Volume Commercial Service	9,796,053	($224,544)	9,571,509	1,825,274	19.07%	11,396,784	3
4	Large Volume Commercial Service	266,035	($19,325)	246,710	45,870	18.59%	292,581	4
5	Commercial Transportation	587,108	($53,884)	533,224	102,862	19.29%	636,086	5
6	Small Volume Industrial Service	121,270	$12,438	133,707	25,498	19.07%	159,205	6
7	Large Volume Industrial Service	125,443	($3,998)	121,445	22,603	18.61%	144,048	7
8	Industrial Transportation	1,103,528	$14,728	1,118,256	213,806	19.12%	1,332,063	8
9	Industrial Transportation - Contracts	659,182	($207,718)	451,464	86,094	19.07%	537,558	9
10	T2 Transportation	63,852	$0	63,852	60	0.09%	63,912	10
11	Small Volume Public Authority	1,677,883	($47,621)	1,630,262	310,889	19.07%	1,941,150	11
12	Large Volume Public Authority	152,764	($3,947)	148,817	27,932	18.77%	176,749	12
13	Public Authority Transportation	622,840	$33,420	656,260	125,595	19.14%	781,855	13
14	Special Gas Light Service	66,940	$0	66,940	12,766	19.07%	79,706	14
15	Irrigation Service	34,092	($227)	33,865	6,458	19.07%	40,322	15
16	Total Gas Service	$52,556,220	($1,398,455)	$51,157,764	$9,480,876	18.53%	$60,638,641	16

UNS Gas, Inc.
Comparison of Present And Proposed Rates
Test Year Ended June 30, 2008

	Present Rate	Proposed Rate	Increase $	Increase %
Residential Service				
Customer Charge, Year 1	$8.50	$10.00	$1.50	17.65%
Distribution Margin Therms	$0.3270	$0.3920	$0.0650	19.88%
Customer Charge, Year 2	$8.50	$12.00	$3.50	41.18%
Distribution Margin Therms	$0.3270	$0.3480	$0.0210	6.42%
Customer Charge, Year 3	$8.50	$14.00	$5.50	64.71%
Distribution Margin Therms	$0.3270	$0.3039	-$0.0231	-7.06%
Residential Service Cares (R12)				
Customer Charge	$7.00	$7.00	$0.00	0.00%
Distribution Margin Therms Summer	$0.3270	$0.3270	$0.00	0.00%
Distribution Margin Therms Winter (First 100 Therms)	$0.1770	$0.1770	$0.00	0.00%
Distribution Margin Therms Winter all additional therms	$0.3270	$0.3270	$0.00	0.00%
Small Commercial Service (C20)				
Customer Charge	$13.50	$15.50	$2.00	14.81%
Distribution Margin Therms	$0.2638	$0.3168	$0.0530	20.09%
Large Commercial Service (C22)				
Customer Charge	$100.00	$105.00	$5.00	5.00%
Distribution Margin Therms	$0.1718	$0.2054	$0.0336	19.59%
Small Volume Industrial Service (I-30):				
Customer Charge	$13.50	$15.50	$2.00	14.81%
Distribution Margin Therms	$0.2356	$0.2808	$0.0452	19.18%
Large Volume Industrial Service (I-32):				
Customer Charge	$100.00	$105.00	$5.00	5.00%
Distribution Margin Therms	$0.0952	$0.1136	$0.0184	19.32%
Small Volume PA (PA-40)				
Customer Charge	$13.50	$15.50	$2.00	14.81%
Distribution Margin Therms	$0.2593	$0.3104	$0.0511	19.69%
Large Volume PA (PA-42)				
Customer Charge	$100.00	$105.00	$5.00	5.00%
Distribution Margin Therms	$0.1198	$0.1430	$0.0232	19.35%
Special Gas Light Service (PA-44):				
Single Orifice	$23.72	$21.57	-$2.15	-9.08%
Double Orifice	$39.53	$43.13	$3.60	9.11%
Triple Orifice	$54.86	$64.70	$9.84	17.94%
Quadruple Orifice	$71.16	$86.27	$15.11	21.23%
Irrigation Service (IR-60)				
Customer Charge	$13.50	$15.50	$2.00	14.81%
Distribution Margin Therms	$0.3192	$0.3804	$0.0612	19.17%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Residential Service (R10)

Customer Charge (Sum: Apr - Nov)	$8.50	$10.00
Distribution Margin Therms	0.3270	0.3920

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5	$10.14	$11.96	$1.83	18.01%
10	$11.77	$13.92	$2.15	18.27%
20	$15.04	$17.84	$2.80	18.62%
35	$19.95	$23.72	$3.78	18.93%
50	$24.85	$29.60	$4.75	19.12%
75	$33.03	$39.40	$6.38	19.31%
100	$41.20	$49.20	$8.00	19.42%
250	$90.25	$108.01	$17.76	19.67%
500	$172.00	$206.01	$34.01	19.77%

Residential Service (R10)

Customer Charge (Win: Dec-Mar)	$8.50	$10.00
Distribution Margin Therms	0.3270	$0.3920

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5	$10.14	$11.96	$1.83	18.01%
10	$11.77	$13.92	$2.15	18.27%
20	$15.04	$17.84	$2.80	18.62%
35	$19.95	$23.72	$3.78	18.93%
50	$24.85	$29.60	$4.75	19.12%
75	$33.03	$39.40	$6.38	19.31%
100	$41.20	$49.20	$8.00	19.42%
250	$90.25	$108.01	$17.76	19.67%
500	$172.00	$206.01	$34.01	19.77%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Residential Service Cares (R12)		
Customer Charge (Summer)	$7.00	$7.00
Distribution Margin Therms	0.3270	0.3270

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5	$8.64	$8.64	$0.00	0.00%
10	$10.27	$10.27	$0.00	0.00%
20	$13.54	$13.54	$0.00	0.00%
35	$18.45	$18.45	$0.00	0.00%
50	$23.35	$23.35	$0.00	0.00%
75	$31.53	$31.53	$0.00	0.00%
100	$39.70	$39.70	$0.00	0.00%
250	$88.75	$88.75	$0.00	0.00%
500	$170.50	$170.50	$0.00	0.00%

Residential Service Cares (R12)		
Customer Charge (Winter)	$7.00	$7.00
Distribution Margin Therms (1st 100 Therms)	0.1770	0.1770
Distribution Margin all additional Therms	0.3270	0.3270

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5	$7.89	$7.89	$0.00	0.00%
10	$8.77	$8.77	$0.00	0.00%
20	$10.54	$10.54	$0.00	0.00%
35	$13.20	$13.20	$0.00	0.00%
50	$15.85	$15.85	$0.00	0.00%
75	$20.28	$20.28	$0.00	0.00%
100	$24.70	$24.70	$0.00	0.00%
250	$73.75	$73.75	$0.00	0.00%
500	$155.50	$155.50	$0.00	0.00%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Small Commercial Service (C20)

Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2638	$0.3168

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$26.69	$31.34	$4.65	17.42%
100	$39.88	$47.18	$7.30	18.30%
500	$145.40	$173.89	$28.49	19.60%
1,000	$277.30	$332.29	$54.99	19.83%
1,500	$409.20	$490.68	$81.48	19.91%
2,500	$673.00	$807.46	$134.46	19.98%
5,000	$1,332.50	$1,599.43	$266.93	20.03%
7,500	$1,992.00	$2,391.39	$399.39	20.05%
10,000	$2,651.50	$3,183.36	$531.86	20.06%

Large Commercial Service (C22)

Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.1718	$0.2054

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
10,001	$1,818	$2,160	$342	18.78%
12,500	$2,248	$2,673	$426	18.94%
15,000	$2,677	$3,187	$510	19.04%
17,500	$3,107	$3,700	$594	19.12%
20,000	$3,536	$4,214	$678	19.17%
25,000	$4,395	$5,241	$846	19.25%
30,000	$5,254	$6,268	$1,014	19.31%
45,000	$7,831	$9,350	$1,519	19.40%
75,000	$12,985	$15,514	$2,529	19.47%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Small Volume Industrial Service (I-30):

Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2356	$0.2808

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$25.28	$29.54	$4.26	16.85%
100	$37.06	$43.58	$6.52	17.59%
500	$131.30	$155.89	$24.59	18.73%
1,000	$249.10	$296.28	$47.18	18.94%
1,500	$366.90	$436.67	$69.77	19.02%
2,500	$602.50	$717.44	$114.94	19.08%
5,000	$1,191.50	$1,419.39	$227.89	19.13%
7,500	$1,780.50	$2,121.33	$340.83	19.14%
10,000	$2,369.50	$2,823.28	$453.78	19.15%

Large Volume Industrial Service (I-32):

Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.0952	$0.1136

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
10,001	$1,052.10	$1,241.03	$188.94	17.96%
15,000	$1,528.00	$1,808.88	$280.88	18.38%
20,000	$2,004.00	$2,376.84	$372.84	18.60%
30,000	$2,956.00	$3,512.76	$556.76	18.83%
50,000	$4,860.00	$5,784.60	$924.60	19.02%
75,000	$7,240.00	$8,624.40	$1,384.40	19.12%
100,000	$9,620.00	$11,464.20	$1,844.20	19.17%
125,000	$12,000.00	$14,304.00	$2,304.00	19.20%
150,000	$14,380.00	$17,143.81	$2,763.81	19.22%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Small Volume Public Authority (PA-40)		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2593	$0.3104

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$26.47	$31.02	$4.55	17.20%
100	$39.43	$46.54	$7.11	18.02%
500	$143.15	$170.68	$27.53	19.23%
1,000	$272.80	$325.85	$53.05	19.45%
1,500	$402.45	$481.03	$78.58	19.52%
2,500	$661.75	$791.38	$129.63	19.59%
5,000	$1,310.00	$1,567.26	$257.26	19.64%
7,500	$1,958.25	$2,343.14	$384.89	19.65%
10,000	$2,606.50	$3,119.02	$512.52	19.66%

Large Volume Public Authority (PA-42)		
Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.1198	$0.1430

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
10,001	$1,298.12	$1,534.93	$236.81	18.24%
15,000	$1,897.00	$2,249.68	$352.68	18.59%
20,000	$2,496.00	$2,964.58	$468.58	18.77%
30,000	$3,694.00	$4,394.36	$700.36	18.96%
50,000	$6,090.00	$7,253.94	$1,163.94	19.11%
75,000	$9,085.00	$10,828.41	$1,743.41	19.19%
100,000	$12,080.00	$14,402.88	$2,322.88	19.23%
125,000	$15,075.00	$17,977.35	$2,902.35	19.25%
150,000	$18,070.00	$21,551.82	$3,481.82	19.27%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Special Gas Light Service (PA-44):		
Customer Charge Lighting Group A	$15.17	$21.57
Customer Charge Lighting Group B	$18.20	$21.57

Average Montly Customers	Annual Bill Present	Annual Bill Proposed	Proposed Increase $	Proposed Increase %
The following is an annual delivery bill per lamp				
Customer Charge Lighting Group A	$182.04	$258.78	$76.74	42.16%
Customer Charge Lighting Group B	$218.40	$258.78	$40.38	18.49%

Note: There is no longer a Group A and Group B rate. All current customers are applicable to the Single Orifice Rate.

Irrigation Service (IR-60)		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.3192	$0.3804

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$29.46	$34.52	$5.06	17.18%
100	$45.42	$53.54	$8.12	17.88%
500	$173.10	$205.70	$32.60	18.83%
1,000	$332.70	$395.90	$63.20	19.00%
1,500	$492.30	$586.11	$93.81	19.05%
2,500	$811.50	$966.51	$155.01	19.10%
5,000	$1,609.50	$1,917.52	$308.02	19.14%
7,500	$2,407.50	$2,868.53	$461.03	19.15%
10,000	$3,205.50	$3,819.54	$614.04	19.16%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
RESIDENTIAL SERVICE RATE R-10							
0	4	147,084	262,849	147,084	9.8%	262,849	0.4%
5	9	171,684	1,192,055	318,768	21.3%	1,454,904	2.1%
10	14	166,473	1,951,866	485,241	32.4%	3,406,770	5.0%
15	19	142,975	2,376,119	628,216	41.9%	5,782,889	8.5%
20	24	104,527	2,253,814	732,742	48.9%	8,036,703	11.8%
25	29	84,218	2,234,609	816,961	54.5%	10,271,312	15.1%
30	34	66,359	2,088,008	883,320	58.9%	12,359,320	18.2%
35	39	56,108	2,043,097	939,427	62.6%	14,402,416	21.2%
40	44	48,058	1,984,852	987,485	65.9%	16,387,268	24.1%
45	49	42,192	1,950,246	1,029,677	68.7%	18,337,514	26.9%
50	54	39,086	2,000,309	1,068,764	71.3%	20,337,823	29.9%
55	59	34,616	1,941,915	1,103,379	73.6%	22,279,738	32.7%
60	64	32,491	1,983,631	1,135,871	75.7%	24,263,369	35.6%
65	69	29,440	1,942,862	1,165,311	77.7%	26,206,230	38.5%
70	74	26,766	1,898,738	1,192,077	79.5%	28,104,968	41.3%
75	79	25,101	1,903,764	1,217,178	81.2%	30,008,732	44.1%
80	84	23,195	1,872,920	1,240,373	82.7%	31,881,652	46.8%
85	89	22,160	1,898,794	1,262,533	84.2%	33,780,446	49.6%
90	94	19,996	1,812,496	1,282,529	85.5%	35,592,943	52.3%
95	99	18,769	1,793,949	1,301,298	86.8%	37,386,892	54.9%
100	104	17,015	1,709,036	1,318,313	87.9%	39,095,928	57.4%
105	109	15,634	1,647,042	1,333,947	89.0%	40,742,969	59.9%
110	114	14,801	1,632,328	1,348,748	89.9%	42,375,297	62.3%
115	119	13,521	1,558,532	1,362,269	90.8%	43,933,829	64.5%
120	124	11,779	1,415,846	1,374,049	91.6%	45,349,675	66.6%
125	129	11,170	1,397,071	1,385,219	92.4%	46,746,747	68.7%
130	134	9,920	1,289,603	1,395,140	93.0%	48,036,349	70.6%
135	139	9,413	1,270,375	1,404,552	93.7%	49,306,724	72.4%
140	144	8,428	1,179,089	1,412,980	94.2%	50,485,813	74.2%
145	149	7,611	1,101,882	1,420,591	94.7%	51,587,695	75.8%
150	154	6,978	1,044,501	1,427,569	95.2%	52,632,196	77.3%
155	159	6,445	996,611	1,434,014	95.6%	53,628,806	78.8%
160	164	5,794	924,943	1,439,808	96.0%	54,553,749	80.1%
165	169	5,115	841,987	1,444,923	96.4%	55,395,736	81.4%
170	174	4,724	800,358	1,449,647	96.7%	56,196,095	82.6%
175	179	4,310	751,397	1,453,957	97.0%	56,947,492	83.7%
180	184	3,945	707,364	1,457,903	97.2%	57,654,856	84.7%
185	189	3,488	642,571	1,461,391	97.5%	58,297,427	85.6%
190	194	3,211	607,402	1,464,602	97.7%	58,904,829	86.5%
195	199	2,802	543,938	1,467,404	97.9%	59,448,767	87.3%
200	299	25,263	5,859,005	1,492,668	99.5%	65,307,772	95.9%
300	399	4,674	1,553,213	1,497,342	99.9%	66,860,985	98.2%
400	499	1,194	518,440	1,498,536	99.9%	67,379,425	99.0%
500	999	884	545,180	1,499,419	100.0%	67,924,605	99.8%
1,000	1,999	76	97,646	1,499,495	100.0%	68,022,251	99.9%
≥ 2,000		17	44,711	1,499,512	100.0%	68,066,962	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
RESIDENTIAL SERVICE RATE R-12							
0	4	5,459	12,331	5,459	6.4%	12,331	0.3%
5	9	10,624	76,405	16,082	18.9%	88,737	2.5%
10	14	10,301	125,639	26,384	31.1%	214,375	6.1%
15	19	9,085	156,305	35,469	41.8%	370,680	10.5%
20	24	6,551	146,395	42,019	49.5%	517,076	14.6%
25	29	5,236	144,026	47,255	55.6%	661,102	18.7%
30	34	4,038	131,678	51,293	60.4%	792,780	22.4%
35	39	3,373	127,317	54,667	64.4%	920,096	26.0%
40	44	3,032	129,564	57,699	67.9%	1,049,660	29.7%
45	49	2,653	127,105	60,352	71.1%	1,176,765	33.3%
50	54	2,453	130,177	62,805	74.0%	1,306,942	37.0%
55	59	2,074	120,537	64,879	76.4%	1,427,479	40.4%
60	64	2,031	128,330	66,910	78.8%	1,555,808	44.0%
65	69	1,801	123,134	68,711	80.9%	1,678,943	47.5%
70	74	1,663	122,206	70,374	82.9%	1,801,149	51.0%
75	79	1,530	120,151	71,904	84.7%	1,921,300	54.4%
80	84	1,361	113,847	73,265	86.3%	2,035,147	57.6%
85	89	1,300	115,400	74,565	87.8%	2,150,548	60.9%
90	94	1,140	107,205	75,706	89.1%	2,257,753	63.9%
95	99	1,045	103,439	76,750	90.4%	2,361,192	66.8%
100	104	903	94,006	77,653	91.4%	2,455,198	69.5%
105	109	823	89,783	78,476	92.4%	2,544,982	72.0%
110	114	787	89,920	79,263	93.3%	2,634,901	74.6%
115	119	661	78,915	79,923	94.1%	2,713,816	76.8%
120	124	557	69,294	80,480	94.8%	2,783,111	78.8%
125	129	504	65,386	80,985	95.4%	2,848,497	80.6%
130	134	458	61,736	81,443	95.9%	2,910,232	82.4%
135	139	445	62,184	81,887	96.4%	2,972,417	84.1%
140	144	362	52,346	82,249	96.9%	3,024,762	85.6%
145	149	349	52,376	82,598	97.3%	3,077,138	87.1%
150	154	258	39,939	82,856	97.6%	3,117,077	88.2%
155	159	230	36,871	83,086	97.8%	3,153,949	89.3%
160	164	209	34,441	83,295	98.1%	3,188,389	90.2%
165	169	167	28,511	83,462	98.3%	3,216,901	91.0%
170	174	194	34,100	83,656	98.5%	3,251,000	92.0%
175	179	137	24,682	83,793	98.7%	3,275,682	92.7%
180	184	128	23,850	83,921	98.8%	3,299,532	93.4%
185	189	126	24,112	84,048	99.0%	3,323,644	94.1%
190	194	98	19,125	84,145	99.1%	3,342,769	94.6%
195	199	108	21,712	84,253	99.2%	3,364,481	95.2%
200	299	591	139,942	84,844	99.9%	3,504,422	99.2%
300	399	70	23,854	84,914	100.0%	3,528,276	99.9%
400	499	7	3,151	84,921	100.0%	3,531,428	99.9%
500	999	3	2,008	84,924	100.0%	3,533,436	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
SMALL VOLUME COMMERCIAL RATE C-20							
0	9	45,637	93,478	45,637	33.4%	93,478	0.3%
10	19	11,797	162,319	57,434	42.0%	255,798	0.9%
20	29	7,608	180,216	65,042	47.6%	436,014	1.5%
30	39	5,567	187,261	70,609	51.7%	623,275	2.1%
40	49	4,652	202,215	75,261	55.1%	825,490	2.8%
50	59	3,958	210,633	79,219	58.0%	1,036,123	3.5%
60	69	3,356	211,655	82,575	60.4%	1,247,778	4.3%
70	79	2,886	210,179	85,461	62.6%	1,457,958	5.0%
80	89	2,573	212,899	88,034	64.4%	1,670,857	5.7%
90	99	2,264	209,493	90,298	66.1%	1,880,350	6.4%
100	109	2,137	218,373	92,436	67.7%	2,098,724	7.2%
110	119	1,947	217,863	94,382	69.1%	2,316,587	7.9%
120	129	1,757	214,256	96,139	70.4%	2,530,842	8.6%
130	139	1,558	205,156	97,698	71.5%	2,735,998	9.3%
140	149	1,480	209,601	99,178	72.6%	2,945,599	10.1%
150	159	1,434	216,925	100,612	73.6%	3,162,524	10.8%
160	169	1,310	211,315	101,922	74.6%	3,373,839	11.5%
170	179	1,173	200,443	103,095	75.5%	3,574,282	12.2%
180	189	1,124	202,795	104,219	76.3%	3,777,076	12.9%
190	199	1,085	206,800	105,304	77.1%	3,983,877	13.6%
200	249	4,395	960,820	109,699	80.3%	4,944,697	16.9%
250	299	3,384	906,615	113,083	82.8%	5,851,312	20.0%
300	349	2,746	871,124	115,829	84.8%	6,722,436	23.0%
350	399	2,247	823,754	118,076	86.4%	7,546,190	25.8%
400	449	1,958	813,951	120,033	87.9%	8,360,141	28.5%
450	499	1,713	796,260	121,747	89.1%	9,156,401	31.3%
500	599	2,650	1,419,229	124,397	91.1%	10,575,631	36.1%
600	699	2,002	1,267,932	126,399	92.5%	11,843,563	40.4%
700	799	1,545	1,129,873	127,944	93.6%	12,973,436	44.3%
800	899	1,212	1,005,484	129,155	94.5%	13,978,920	47.7%
900	999	916	849,267	130,071	95.2%	14,828,187	50.6%
1,000	1,499	2,912	3,475,058	132,984	97.3%	18,303,245	62.5%
1,500	1,999	1,443	2,438,885	134,426	98.4%	20,742,130	70.8%
2,000	2,999	1,145	2,706,208	135,572	99.2%	23,448,338	80.1%
3,000	3,999	416	1,391,628	135,988	99.5%	24,839,965	84.8%
4,000	4,999	183	793,480	136,170	99.7%	25,633,445	87.5%
5,000	5,999	132	712,597	136,303	99.8%	26,346,042	89.9%
6,000	6,999	84	533,014	136,387	99.8%	26,879,056	91.8%
7,000	7,999	62	455,483	136,449	99.9%	27,334,539	93.3%
8,000	8,999	37	303,016	136,486	99.9%	27,637,555	94.4%
9,000	9,999	39	358,260	136,524	99.9%	27,995,815	95.6%
10,000	10,999	32	323,236	136,556	100.0%	28,319,051	96.7%
11,000	11,999	22	244,189	136,578	100.0%	28,563,240	97.5%
12,000	12,999	13	156,847	136,590	100.0%	28,720,087	98.0%
13,000	13,999	1	13,058	136,591	100.0%	28,733,145	98.1%
14,000	14,999	9	127,467	136,600	100.0%	28,860,612	98.5%
≥ 15,000		20	431,045	136,620	100.0%	29,291,657	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
LARGE VOLUME COMMERCIAL RATE C-22							
0	249	51	2,411	51	30.4%	2,411	0.2%
250	499	15	5,249	66	39.1%	7,660	0.6%
500	749	15	9,297	80	47.8%	16,957	1.3%
750	999	1	914	81	48.4%	17,872	1.3%
1,000	1,999	2	2,561	83	49.5%	20,432	1.5%
2,000	2,999	2	5,483	85	50.5%	25,915	1.9%
3,000	3,999	5	19,333	90	53.8%	45,248	3.4%
4,000	4,999	3	13,056	93	55.4%	58,304	4.4%
5,000	5,999	7	41,464	100	59.8%	99,768	7.5%
6,000	6,999	6	42,774	107	63.6%	142,542	10.7%
7,000	7,999	3	21,534	110	65.2%	164,076	12.3%
8,000	8,999	4	32,672	113	67.4%	196,748	14.7%
9,000	9,999	3	26,598	116	69.0%	223,346	16.7%
10,000	19,999	34	564,529	150	89.1%	787,875	58.9%
20,000	29,999	12	295,317	162	96.2%	1,083,192	80.9%
30,000	39,999	5	161,749	166	98.9%	1,244,941	93.0%
40,000	49,999	1	46,128	167	99.5%	1,291,069	96.5%
50,000	59,999	1	47,176	168	100.0%	1,338,244	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
SMALL VOLUME INDUSTRIAL RATE I-30							
0	249	82	3,300	82	34.3%	3,300	0.6%
250	499	13	4,204	95	39.5%	7,503	1.4%
500	749	17	9,111	112	46.7%	16,614	3.0%
750	999	11	8,272	123	51.4%	24,886	4.5%
1,000	1,499	13	13,631	136	56.7%	38,517	7.0%
1,500	1,999	8	12,616	144	60.0%	51,133	9.2%
2,000	2,499	3	6,545	147	61.4%	57,678	10.4%
2,500	2,999	8	19,539	155	64.8%	77,217	13.9%
3,000	3,499	13	35,039	168	70.0%	112,255	20.3%
3,500	3,999	9	28,921	177	73.8%	141,176	25.5%
4,000	4,499	5	16,855	182	75.7%	158,031	28.5%
4,500	4,999	7	28,308	189	78.6%	186,339	33.6%
5,000	5,499	10	47,089	199	82.9%	233,428	42.2%
5,500	5,999	8	40,151	207	86.2%	273,579	49.4%
6,000	6,499	1	6,130	208	86.7%	279,709	50.5%
6,500	6,999	8	46,506	216	90.0%	326,215	58.9%
7,000	7,499	6	35,617	222	92.4%	361,832	65.3%
7,500	7,999	3	22,790	225	93.8%	384,622	69.5%
8,500	8,999	2	16,928	227	94.8%	401,550	72.5%
9,000	9,499	1	8,968	229	95.2%	410,518	74.1%
9,500	9,999	1	9,325	230	95.7%	419,843	75.8%
10,000	10,999	1	9,939	231	96.2%	429,782	77.6%
11,000	11,999	2	23,175	233	97.1%	452,957	81.8%
12,000	12,999	2	24,844	235	98.1%	477,800	86.3%
14,000	14,999	2	28,452	238	99.0%	506,252	91.4%
19,000	19,999	1	19,143	239	99.5%	525,395	94.9%
28,000	28,999	1	28,371	240	100.0%	553,766	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
LARGE VOLUME INDUSTRIAL RATE I-32							
0	499	9	517	9	15.7%	517	0.0%
500	999	3	2,178	12	20.0%	2,695	0.2%
1,000	1,999	1	1,570	13	21.4%	4,265	0.4%
3,000	3,999	1	3,182	14	22.9%	7,447	0.6%
4,000	4,999	2	8,248	15	25.7%	15,695	1.3%
5,000	9,999	9	91,679	25	41.4%	107,374	8.9%
10,000	14,999	11	160,059	36	60.0%	267,433	22.1%
15,000	19,999	10	205,704	46	77.1%	473,137	39.0%
20,000	29,999	6	162,332	52	87.1%	635,469	52.4%
30,000	39,999	2	66,882	54	90.0%	702,351	57.9%
40,000	49,999	1	40,506	55	91.4%	742,857	61.3%
50,000	59,999	1	52,592	56	92.9%	795,449	65.6%
60,000	69,999	2	128,029	57	95.7%	923,478	76.2%
75,000	125,000	3	289,176	60	100.0%	1,212,653	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
SMALL VOLUME PUBLIC AUTHORITY RATE P-40							
0	49	5,942	72,013	5,942	46.5%	72,013	1.3%
50	99	1,332	93,099	1,332	10.4%	165,112	2.9%
100	199	1,367	190,289	1,367	10.7%	355,400	6.3%
200	299	745	177,867	745	5.8%	533,268	9.5%
300	399	545	181,987	545	4.3%	715,255	12.7%
400	499	418	181,359	418	3.3%	896,614	16.0%
500	599	293	155,157	293	2.3%	1,051,772	18.7%
600	699	220	137,566	220	1.7%	1,189,337	21.2%
700	799	203	146,683	203	1.6%	1,336,021	23.8%
800	899	161	131,699	161	1.3%	1,467,720	26.2%
900	999	133	122,012	133	1.0%	1,589,732	28.3%
1,000	1,999	698	956,175	698	5.5%	2,545,906	45.4%
2,000	2,999	301	711,158	301	2.4%	3,257,065	58.1%
3,000	3,999	134	443,779	134	1.0%	3,700,844	66.0%
4,000	4,999	105	453,501	105	0.8%	4,154,345	74.0%
5,000	6,999	97	545,552	97	0.8%	4,699,896	83.8%
7,000	9,999	47	381,443	47	0.4%	5,081,339	90.6%
10,000	19,999	34	438,273	34	0.3%	5,519,612	98.4%
20,000	29,999	4	91,041	4	0.0%	5,610,653	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
LARGE VOLUME PUBLIC AUTHORITY RATE P-42							
600	799	1	605	1	1.7%	605	0.1%
800	999	2	1,742	3	5.0%	2,346	0.2%
1,000	5,999	4	5,281	7	11.7%	7,627	0.6%
6,000	7,999	4	26,637	11	18.3%	34,264	2.9%
8,000	9,999	5	41,881	16	26.7%	76,146	6.4%
10,000	12,999	8	89,684	24	40.0%	165,830	13.9%
13,000	15,999	3	44,641	27	45.0%	210,471	17.7%
16,000	18,999	5	82,950	32	53.3%	293,421	24.6%
19,000	23,999	6	115,842	38	63.3%	409,264	34.3%
24,000	26,999	8	199,194	46	76.7%	608,458	51.0%
27,000	29,999	3	82,833	49	81.7%	691,290	58.0%
30,000	39,999	4	135,070	53	88.3%	826,361	69.3%
40,000	59,999	5	235,294	58	96.7%	1,061,655	89.1%
60,000	70,000	2	130,475	60	100.0%	1,192,130	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
IRRIGATION SERVICE RATE I-60							
0	99	40	215	40	66.7%	215	0.2%
100	199	3	406	43	71.7%	620	0.6%
1,700	1,799	1	1,821	44	73.3%	2,441	2.4%
1,800	1,899	1	1,901	45	75.0%	4,343	4.2%
1,900	1,999	1	1,982	46	76.7%	6,325	6.1%
2,100	2,199	1	2,276	47	78.3%	8,600	8.3%
2,200	2,299	1	2,340	48	80.0%	10,941	10.6%
2,400	2,499	1	2,546	49	81.7%	13,486	13.0%
2,900	2,999	1	3,107	50	83.3%	16,593	16.0%
3,000	3,099	1	3,153	51	85.0%	19,746	19.1%
3,200	3,299	1	3,411	52	86.7%	23,157	22.4%
3,400	3,499	1	3,644	53	88.3%	26,802	25.9%
3,600	3,699	1	3,846	54	90.0%	30,647	29.6%
4,200	4,299	1	4,450	55	91.7%	35,098	33.9%
4,400	4,499	1	4,654	56	93.3%	39,751	38.4%
10,500	10,599	1	10,996	57	95.0%	50,747	49.0%
11,900	11,999	1	12,416	58	96.7%	63,163	61.0%
16,900	16,999	1	17,693	59	98.3%	80,856	78.1%
21,700	21,799	1	22,699	60	100.0%	103,554	100.0%

EXHIBIT
UNSG-3
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
DOCKET CONTROL

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

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571 **NOTICE OF FILING REVISED "H-1" SCHEDULE**

UNS Gas, Inc., through undersigned counsel, hereby files a revised "H-1" Schedule. This revised "H-1" Schedule replaces the schedule that was filed with the Application on November 7, 2008.

RESPECTFULLY SUBMITTED this 5th day of December 2008.

UNS Gas, Inc.

By _____

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Original and 13 copies of the foregoing
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Phoenix, Arizona 85007

Copy of the foregoing hand-delivered/mailed
this 5th day of December, 2008, to:

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Phoenix, Arizona 85007

Commissioner William A. Mundell
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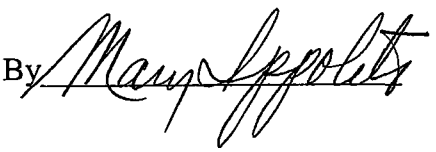
1200 West Washington Street
Phoenix, Arizona 85007

By 

UNS Gas, Inc.
Summary of Revenues by Customer Classifications
Adjusted Present Rates And Proposed Rates
Test Year Ended June 30, 2008
(Thousands of Dollars)

Line No.	Class of Service	Present Rates Unadjusted (1.)	Present Rates Adjusted	Proposed Rates	Proposed Net Increase Relative to Present Rates Unadjusted	Proposed Net Increase Relative to Present Rates Unadjusted As a Percentage	Proposed Net Increase Relative to Present Rates Adjusted	Proposed Net Increase Relative to Present Rates Adjusted As a Percentage	Line No.
1	Residential Service	$37,279,231	$36,381,453	$43,056,622	$5,777,391	15.50%	$6,675,169	18.35%	1
2	Commercial Gas Service	10,062,088	9,818,220	11,689,364	$1,627,276	16.17%	1,871,145	19.06%	2
3	Industrial Gas Service	246,712	255,152	303,253	$56,541	22.92%	48,101	18.85%	3
4	Public Authority Gas Service	1,830,646	1,779,079	2,117,900	$287,253	15.69%	338,821	19.04%	4
5	Special Gas Light Service	66,940	66,940	79,706	$12,766	19.07%	12,766	19.07%	5
6	Irrigation Service	34,092	33,865	40,322	$6,231	18.28%	6,458	19.07%	6
7	Transportation Customers	3,036,509	2,823,056	3,351,473	$314,964	10.37%	528,417	18.72%	7
8	Subtotal	52,556,220 (2.)	51,157,764	60,638,641	8,082,421	15.38%	9,480,876	18.53%	8
9	Other Operating Revenue	1,636,425	1,744,743	1,744,743	108,318 (3.)	6.62%	0	0.00%	9
10	Total	$54,192,645	$52,902,507	$62,383,384	$8,190,739	15.11%	$9,480,876	17.92%	10

Supporting Schedules	Recap Schedules
H-2 (P2)	A-1

Note 1. - Excludes PGA Revenues

Note 2. - Ties to H-2, page 2 of 2.

Note 3. - Net of DSM Revenue and Expense Adjustment (-$130,917) and Service Fees and Late Fees Adjustment ($239,235).

EXHIBIT
DOCKET
UNSG-4
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

RECEIVED
2008 DEC -4 P 4:17
AZ CORP COMMISSION
DOCKET CONTROL

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

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571 **NOTICE OF FILING REVISED "H-5" SCHEDULE**

UNS Gas, Inc., through undersigned counsel, hereby files a revised "H-5" Schedule. This revised "H-5" Schedule replaces the schedule that was filed with the Application on November 7, 2008.

RESPECTFULLY SUBMITTED this 4th day of December 2008.

UNS Gas, Inc.

By _____

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Attorneys for UNS Gas, Inc.

Original and 13 copies of the foregoing
filed this 4th day of December, 2008, with:

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

Copy of the foregoing hand-delivered/mailed
this 4th day of December, 2008, to:

Chairman Mike Gleason
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner William A. Mundell
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner Jeff Hatch-Miller
Arizona Corporation Commission
1200 West Washington Street
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Commissioner Kristen K. Mayes
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Phoenix, Arizona 85007

Commissioner Gary Pierce
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By Mary Appolito

UNS Gas Inc.
Residential Bill Count
Test Year Ended June 30, 2008
REVISED TO INCLUDE AVERAGE CUSTOMERS AND THERMS AND MEDIAN THERMS

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
RESIDENTIAL SERVICE RATE R-10							
0	4	147,084	262,849	147,084	9.8%	262,849	0.4%
5	9	171,684	1,192,055	318,768	21.3%	1,454,904	2.1%
10	14	166,473	1,951,866	485,241	32.4%	3,406,770	5.0%
15	19	142,975	2,376,119	628,216	41.9%	5,782,889	8.5%
20	24	104,527	2,253,814	732,742	48.9%	8,036,703	11.8%
25	29	84,218	2,234,609	816,961	54.5%	10,271,312	15.1%
30	34	66,359	2,088,008	883,320	58.9%	12,359,320	18.2%
35	39	56,108	2,043,097	939,427	62.6%	14,402,416	21.2%
40	44	48,058	1,984,852	987,485	65.9%	16,387,268	24.1%
45	49	42,192	1,950,246	1,029,677	68.7%	18,337,514	26.9%
50	54	39,086	2,000,309	1,068,764	71.3%	20,337,823	29.9%
55	59	34,616	1,941,915	1,103,379	73.6%	22,279,738	32.7%
60	64	32,491	1,983,631	1,135,871	75.7%	24,263,369	35.6%
65	69	29,440	1,942,862	1,165,311	77.7%	26,206,230	38.5%
70	74	26,766	1,898,738	1,192,077	79.5%	28,104,968	41.3%
75	79	25,101	1,903,764	1,217,178	81.2%	30,008,732	44.1%
80	84	23,195	1,872,920	1,240,373	82.7%	31,881,652	46.8%
85	89	22,160	1,898,794	1,262,533	84.2%	33,780,446	49.6%
90	94	19,996	1,812,496	1,282,529	85.5%	35,592,943	52.3%
95	99	18,769	1,793,949	1,301,298	86.8%	37,386,892	54.9%
100	104	17,015	1,709,036	1,318,313	87.9%	39,095,928	57.4%
105	109	15,634	1,647,042	1,333,947	89.0%	40,742,969	59.9%
110	114	14,801	1,632,328	1,348,748	89.9%	42,375,297	62.3%
115	119	13,521	1,558,532	1,362,269	90.8%	43,933,829	64.5%
120	124	11,779	1,415,846	1,374,049	91.6%	45,349,675	66.6%
125	129	11,170	1,397,071	1,385,219	92.4%	46,746,747	68.7%
130	134	9,920	1,289,603	1,395,140	93.0%	48,036,349	70.6%
135	139	9,413	1,270,375	1,404,552	93.7%	49,306,724	72.4%
140	144	8,428	1,179,089	1,412,980	94.2%	50,485,813	74.2%
145	149	7,611	1,101,882	1,420,591	94.7%	51,587,695	75.8%
150	154	6,978	1,044,501	1,427,569	95.2%	52,632,196	77.3%
155	159	6,445	996,611	1,434,014	95.6%	53,628,806	78.8%
160	164	5,794	924,943	1,439,808	96.0%	54,553,749	80.1%
165	169	5,115	841,987	1,444,923	96.4%	55,395,736	81.4%
170	174	4,724	800,358	1,449,647	96.7%	56,196,095	82.6%
175	179	4,310	751,397	1,453,957	97.0%	56,947,492	83.7%
180	184	3,945	707,364	1,457,903	97.2%	57,654,856	84.7%
185	189	3,488	642,571	1,461,391	97.5%	58,297,427	85.6%
190	194	3,211	607,402	1,464,602	97.7%	58,904,829	86.5%
195	199	2,802	543,938	1,467,404	97.9%	59,448,767	87.3%
200	299	25,263	5,859,005	1,492,668	99.5%	65,307,772	95.9%
300	399	4,674	1,553,213	1,497,342	99.9%	66,860,985	98.2%
400	499	1,194	518,440	1,498,536	99.9%	67,379,425	99.0%
500	999	884	545,180	1,499,419	100.0%	67,924,605	99.8%
1,000	1,999	76	97,646	1,499,495	100.0%	68,022,251	99.9%
≥ 2,000		17	44,711	1,499,512	100.0%	68,066,962	100.0%

Average Customers	124,959
Average Therms	545
Median Therms	304

UNS Gas Inc.
Residential Bill Count
Test Year Ended June 30, 2008
REVISED TO INCLUDE AVERAGE CUSTOMERS AND THERMS AND MEDIAN THERMS

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
RESIDENTIAL SERVICE RATE R-12							
0	4	5,459	12,331	5,459	6.4%	12,331	0.3%
5	9	10,624	76,405	16,082	18.9%	88,737	2.5%
10	14	10,301	125,639	26,384	31.1%	214,375	6.1%
15	19	9,085	156,305	35,469	41.8%	370,680	10.5%
20	24	6,551	146,395	42,019	49.5%	517,076	14.6%
25	29	5,236	144,026	47,255	55.6%	661,102	18.7%
30	34	4,038	131,678	51,293	60.4%	792,780	22.4%
35	39	3,373	127,317	54,667	64.4%	920,096	26.0%
40	44	3,032	129,564	57,699	67.9%	1,049,660	29.7%
45	49	2,653	127,105	60,352	71.1%	1,176,765	33.3%
50	54	2,453	130,177	62,805	74.0%	1,306,942	37.0%
55	59	2,074	120,537	64,879	76.4%	1,427,479	40.4%
60	64	2,031	128,330	66,910	78.8%	1,555,808	44.0%
65	69	1,801	123,134	68,711	80.9%	1,678,943	47.5%
70	74	1,663	122,206	70,374	82.9%	1,801,149	51.0%
75	79	1,530	120,151	71,904	84.7%	1,921,300	54.4%
80	84	1,361	113,847	73,265	86.3%	2,035,147	57.6%
85	89	1,300	115,400	74,565	87.8%	2,150,548	60.9%
90	94	1,140	107,205	75,706	89.1%	2,257,753	63.9%
95	99	1,045	103,439	76,750	90.4%	2,361,192	66.8%
100	104	903	94,006	77,653	91.4%	2,455,198	69.5%
105	109	823	89,783	78,476	92.4%	2,544,982	72.0%
110	114	787	89,920	79,263	93.3%	2,634,901	74.6%
115	119	661	78,915	79,923	94.1%	2,713,816	76.8%
120	124	557	69,294	80,480	94.8%	2,783,111	78.8%
125	129	504	65,386	80,985	95.4%	2,848,497	80.6%
130	134	458	61,736	81,443	95.9%	2,910,232	82.4%
135	139	445	62,184	81,887	96.4%	2,972,417	84.1%
140	144	362	52,346	82,249	96.9%	3,024,762	85.6%
145	149	349	52,376	82,598	97.3%	3,077,138	87.1%
150	154	258	39,939	82,856	97.6%	3,117,077	88.2%
155	159	230	36,871	83,086	97.8%	3,153,949	89.3%
160	164	209	34,441	83,295	98.1%	3,188,389	90.2%
165	169	167	28,511	83,462	98.3%	3,216,901	91.0%
170	174	194	34,100	83,656	98.5%	3,251,000	92.0%
175	179	137	24,682	83,793	98.7%	3,275,682	92.7%
180	184	128	23,850	83,921	98.8%	3,299,532	93.4%
185	189	126	24,112	84,048	99.0%	3,323,644	94.1%
190	194	98	19,125	84,145	99.1%	3,342,769	94.6%
195	199	108	21,712	84,253	99.2%	3,364,481	95.2%
200	299	591	139,942	84,844	99.9%	3,504,422	99.2%
300	399	70	23,854	84,914	100.0%	3,528,276	99.9%
400	499	7	3,151	84,921	100.0%	3,531,428	99.9%
500	999	3	2,008	84,924	100.0%	3,533,436	100.0%

Average Customers	7,077
Average Therms	499
Median Therms	310

UNS Gas Inc.
Residential Bill Count
Test Year Ended June 30, 2008
REVISED TO INCLUDE AVERAGE CUSTOMERS AND THERMS AND MEDIAN THERMS

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
SMALL VOLUME COMMERCIAL RATE C-20							
0	9	45,637	93,478	45,637	33.4%	93,478	0.3%
10	19	11,797	162,319	57,434	42.0%	255,798	0.9%
20	29	7,608	180,216	65,042	47.6%	436,014	1.5%
30	39	5,567	187,261	70,609	51.7%	623,275	2.1%
40	49	4,652	202,215	75,261	55.1%	825,490	2.8%
50	59	3,958	210,633	79,219	58.0%	1,036,123	3.5%
60	69	3,356	211,655	82,575	60.4%	1,247,778	4.3%
70	79	2,886	210,179	85,461	62.6%	1,457,958	5.0%
80	89	2,573	212,899	88,034	64.4%	1,670,857	5.7%
90	99	2,264	209,493	90,298	66.1%	1,880,350	6.4%
100	109	2,137	218,373	92,436	67.7%	2,098,724	7.2%
110	119	1,947	217,863	94,382	69.1%	2,316,587	7.9%
120	129	1,757	214,256	96,139	70.4%	2,530,842	8.6%
130	139	1,558	205,156	97,698	71.5%	2,735,998	9.3%
140	149	1,480	209,601	99,178	72.6%	2,945,599	10.1%
150	159	1,434	216,925	100,612	73.6%	3,162,524	10.8%
160	169	1,310	211,315	101,922	74.6%	3,373,839	11.5%
170	179	1,173	200,443	103,095	75.5%	3,574,282	12.2%
180	189	1,124	202,795	104,219	76.3%	3,777,076	12.9%
190	199	1,085	206,800	105,304	77.1%	3,983,877	13.6%
200	249	4,395	960,820	109,699	80.3%	4,944,697	16.9%
250	299	3,384	906,615	113,083	82.8%	5,851,312	20.0%
300	349	2,746	871,124	115,829	84.8%	6,722,436	23.0%
350	399	2,247	823,754	118,076	86.4%	7,546,190	25.8%
400	449	1,958	813,951	120,033	87.9%	8,360,141	28.5%
450	499	1,713	796,260	121,747	89.1%	9,156,401	31.3%
500	599	2,650	1,419,229	124,397	91.1%	10,575,631	36.1%
600	699	2,002	1,267,932	126,399	92.5%	11,843,563	40.4%
700	799	1,545	1,129,873	127,944	93.6%	12,973,436	44.3%
800	899	1,212	1,005,484	129,155	94.5%	13,978,920	47.7%
900	999	916	849,267	130,071	95.2%	14,828,187	50.6%
1,000	1,499	2,912	3,475,058	132,984	97.3%	18,303,245	62.5%
1,500	1,999	1,443	2,438,885	134,426	98.4%	20,742,130	70.8%
2,000	2,999	1,145	2,706,208	135,572	99.2%	23,448,338	80.1%
3,000	3,999	416	1,391,628	135,988	99.5%	24,839,965	84.8%
4,000	4,999	183	793,480	136,170	99.7%	25,633,445	87.5%
5,000	5,999	132	712,597	136,303	99.8%	26,346,042	89.9%
6,000	6,999	84	533,014	136,387	99.8%	26,879,056	91.8%
7,000	7,999	62	455,483	136,449	99.9%	27,334,539	93.3%
8,000	8,999	37	303,016	136,486	99.9%	27,637,555	94.4%
9,000	9,999	39	358,260	136,524	99.9%	27,995,815	95.6%
10,000	10,999	32	323,236	136,556	100.0%	28,319,051	96.7%
11,000	11,999	22	244,189	136,578	100.0%	28,563,240	97.5%
12,000	12,999	13	156,847	136,590	100.0%	28,720,087	98.0%
13,000	13,999	1	13,058	136,591	100.0%	28,733,145	98.1%
14,000	14,999	9	127,467	136,600	100.0%	28,860,612	98.5%
≥ 15,000		20	431,045	136,620	100.0%	29,291,657	100.0%

Average Customers	11,385
Average Therms	2,573
Median Therms	413

UNS Gas Inc.
Residential Bill Count
Test Year Ended June 30, 2008
REVISED TO INCLUDE AVERAGE CUSTOMERS AND THERMS AND MEDIAN THERMS

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
LARGE VOLUME COMMERCIAL RATE C-22							
0	249	51	2,411	51	30.4%	2,411	0.2%
250	499	15	5,249	66	39.1%	7,660	0.6%
500	749	15	9,297	80	47.8%	16,957	1.3%
750	999	1	914	81	48.4%	17,872	1.3%
1,000	1,999	2	2,561	83	49.5%	20,432	1.5%
2,000	2,999	2	5,483	85	50.5%	25,915	1.9%
3,000	3,999	5	19,333	90	53.8%	45,248	3.4%
4,000	4,999	3	13,056	93	55.4%	58,304	4.4%
5,000	5,999	7	41,464	100	59.8%	99,768	7.5%
6,000	6,999	6	42,774	107	63.6%	142,542	10.7%
7,000	7,999	3	21,534	110	65.2%	164,076	12.3%
8,000	8,999	4	32,672	113	67.4%	196,748	14.7%
9,000	9,999	3	26,598	116	69.0%	223,346	16.7%
10,000	19,999	34	564,529	150	89.1%	787,875	58.9%
20,000	29,999	12	295,317	162	96.2%	1,083,192	80.9%
30,000	39,999	5	161,749	166	98.9%	1,244,941	93.0%
40,000	49,999	1	46,128	167	99.5%	1,291,069	96.5%
50,000	59,999	1	47,176	168	100.0%	1,338,244	100.0%

Average Customers	14
Average Therms	95,589
Median Therms	36,031

UNS Gas Inc.
Residential Bill Count
Test Year Ended June 30, 2008
REVISED TO INCLUDE AVERAGE CUSTOMERS AND THERMS AND MEDIAN THERMS

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
SMALL VOLUME INDUSTRIAL RATE I-30							
0	249	82	3,300	82	34.3%	3,300	0.6%
250	499	13	4,204	95	39.5%	7,503	1.4%
500	749	17	9,111	112	46.7%	16,614	3.0%
750	999	11	8,272	123	51.4%	24,886	4.5%
1,000	1,499	13	13,631	136	56.7%	38,517	7.0%
1,500	1,999	8	12,616	144	60.0%	51,133	9.2%
2,000	2,499	3	6,545	147	61.4%	57,678	10.4%
2,500	2,999	8	19,539	155	64.8%	77,217	13.9%
3,000	3,499	13	35,039	168	70.0%	112,255	20.3%
3,500	3,999	9	28,921	177	73.8%	141,176	25.5%
4,000	4,499	5	16,855	182	75.7%	158,031	28.5%
4,500	4,999	7	28,308	189	78.6%	186,339	33.6%
5,000	5,499	10	47,089	199	82.9%	233,428	42.2%
5,500	5,999	8	40,151	207	86.2%	273,579	49.4%
6,000	6,499	1	6,130	208	86.7%	279,709	50.5%
6,500	6,999	8	46,506	216	90.0%	326,215	58.9%
7,000	7,499	6	35,617	222	92.4%	361,832	65.3%
7,500	7,999	3	22,790	225	93.8%	384,622	69.5%
8,500	8,999	2	16,928	227	94.8%	401,550	72.5%
9,000	9,499	1	8,968	229	95.2%	410,518	74.1%
9,500	9,999	1	9,325	230	95.7%	419,843	75.8%
10,000	10,999	1	9,939	231	96.2%	429,782	77.6%
11,000	11,999	2	23,175	233	97.1%	452,957	81.8%
12,000	12,999	2	24,844	235	98.1%	477,800	86.3%
14,000	14,999	2	28,452	238	99.0%	506,252	91.4%
19,000	19,999	1	19,143	239	99.5%	525,395	94.9%
28,000	28,999	1	28,371	240	100.0%	553,766	100.0%
	Average Customers		20				
	Average Therms		27,688				
	Median Therms		9,283				
LARGE VOLUME INDUSTRIAL RATE I-32							
0	499	9	517	9	15.7%	517	0.0%
500	999	3	2,178	12	20.0%	2,695	0.2%
1,000	1,999	1	1,570	13	21.4%	4,265	0.4%
3,000	3,999	1	3,182	14	22.9%	7,447	0.6%
4,000	4,999	2	8,248	15	25.7%	15,695	1.3%
5,000	9,999	9	91,679	25	41.4%	107,374	8.9%
10,000	14,999	11	160,059	36	60.0%	267,433	22.1%
15,000	19,999	10	205,704	46	77.1%	473,137	39.0%
20,000	29,999	6	162,332	52	87.1%	635,469	52.4%
30,000	39,999	2	66,882	54	90.0%	702,351	57.9%
40,000	49,999	1	40,506	55	91.4%	742,857	61.3%
50,000	59,999	1	52,592	56	92.9%	795,449	65.6%
60,000	69,999	2	128,029	57	95.7%	923,478	76.2%
75,000	125,000	3	289,176	60	100.0%	1,212,653	100.0%
gap							
	Average Customers		5				
	Average Therms		242,531				
	Median Therms		170,064				

UNS Gas Inc.
Residential Bill Count
Test Year Ended June 30, 2008
REVISED TO INCLUDE AVERAGE CUSTOMERS AND THERMS AND MEDIAN THERMS

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
SMALL VOLUME PUBLIC AUTHORITY RATE P-40							
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
0	49	5,981	72,034	5,981	46.5%	72,034	1.3%
50	99	1,341	93,126	7,321	56.9%	165,160	2.9%
100	199	1,376	190,345	8,697	67.6%	355,505	6.3%
200	299	750	177,920	9,447	73.4%	533,425	9.5%
300	399	548	182,041	9,995	77.7%	715,466	12.7%
400	499	420	181,413	10,416	81.0%	896,879	16.0%
500	599	295	155,203	10,711	83.3%	1,052,082	18.7%
600	699	222	137,606	10,933	85.0%	1,189,688	21.2%
700	799	205	146,727	11,137	86.6%	1,336,415	23.8%
800	899	162	131,738	11,300	87.8%	1,468,153	26.2%
900	999	134	122,048	11,434	88.9%	1,590,201	28.3%
1,000	1,999	703	956,457	12,136	94.3%	2,546,657	45.4%
2,000	2,999	303	711,368	12,440	96.7%	3,258,026	58.1%
3,000	3,999	135	443,910	12,575	97.8%	3,701,936	66.0%
4,000	4,999	106	453,634	12,681	98.6%	4,155,570	74.0%
5,000	6,999	98	545,713	12,778	99.3%	4,701,283	83.8%
7,000	9,999	47	381,556	12,826	99.7%	5,082,838	90.6%
10,000	19,999	34	438,402	12,860	100.0%	5,521,240	98.4%
20,000	29,999	4	91,068	12,864	100.0%	5,612,308	100.0%
	Average Customers		1,072				
	Average Therms		5,236				
	Median Therms		1,128				
LARGE VOLUME PUBLIC AUTHORITY RATE P-42							
600	799	1	605	1	1.7%	605	0.1%
800	999	2	1,742	3	5.0%	2,346	0.2%
1,000	5,999	4	5,281	7	11.7%	7,627	0.6%
6,000	7,999	4	26,637	11	18.3%	34,264	2.9%
8,000	9,999	5	41,881	16	26.7%	76,146	6.4%
10,000	12,999	8	89,684	24	40.0%	165,830	13.9%
13,000	15,999	3	44,641	27	45.0%	210,471	17.7%
16,000	18,999	5	82,950	32	53.3%	293,421	24.6%
19,000	23,999	6	115,842	38	63.3%	409,264	34.3%
24,000	26,999	8	199,194	46	76.7%	608,458	51.0%
27,000	29,999	3	82,833	49	81.7%	691,290	58.0%
30,000	39,999	4	135,070	53	88.3%	826,361	69.3%
40,000	59,999	5	235,294	58	96.7%	1,061,655	89.1%
60,000	70,000	2	130,475	60	100.0%	1,192,130	100.0%
	Average Customers		5				
	Average Therms		238,426				
	Median Therms		202,679				

UNS Gas Inc.
Residential Bill Count
Test Year Ended June 30, 2008
REVISED TO INCLUDE AVERAGE CUSTOMERS AND THERMS AND MEDIAN THERMS

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
IRRIGATION SERVICE RATE I-60							
0	99	40	215	40	66.7%	215	0.2%
100	199	3	406	43	71.7%	620	0.6%
1,700	1,799	1	1,821	44	73.3%	2,441	2.4%
1,800	1,899	1	1,901	45	75.0%	4,343	4.2%
1,900	1,999	1	1,982	46	76.7%	6,325	6.1%
2,100	2,199	1	2,276	47	78.3%	8,600	8.3%
2,200	2,299	1	2,340	48	80.0%	10,941	10.6%
2,400	2,499	1	2,546	49	81.7%	13,486	13.0%
2,900	2,999	1	3,107	50	83.3%	16,593	16.0%
3,000	3,099	1	3,153	51	85.0%	19,746	19.1%
3,200	3,299	1	3,411	52	86.7%	23,157	22.4%
3,400	3,499	1	3,644	53	88.3%	26,802	25.9%
3,600	3,699	1	3,846	54	90.0%	30,647	29.6%
4,200	4,299	1	4,450	55	91.7%	35,098	33.9%
4,400	4,499	1	4,654	56	93.3%	39,751	38.4%
10,500	10,599	1	10,996	57	95.0%	50,747	49.0%
11,900	11,999	1	12,416	58	96.7%	63,163	61.0%
16,900	16,999	1	17,693	59	98.3%	80,856	78.1%
21,700	21,799	1	22,699	60	100.0%	103,554	100.0%

Average Customers	5
Average Therms	20,711
Median Therms	891

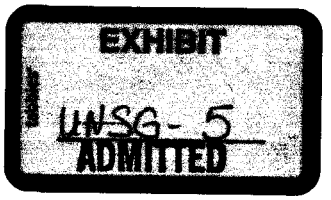
SPECIAL GAS LIGHT SERVICE PA-44

	ANNUAL NUMBER OF LAMPS
Customer Lighting Group A	108
Customer Lighting Group B	3,588

Average & Median Customer Lighting Group A	9
Average & Median Customer Lighting Group B	299

BEFORE THE ARIZONA CORPORATION COMMISSION

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



IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-____

Direct Testimony of

David G. Hutchens

on Behalf of

UNS Gas, Inc.

November 7, 2008

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Exhibits

Exhibit DGH-1 Map of UNS Gas Certificated Area

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is David G. Hutchens. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. By whom are you employed and what is your position?

I am employed by both Tucson Electric Power Company ("TEP" or the "Company") and UNS Gas, Inc. ("UNS Gas"). I have operational responsibility for UNS Gas as its Vice President of Operations. My position at TEP is Vice President, Wholesale Energy. I oversee the fuel and wholesale power procurement, trading, marketing and risk management functions for TEP and its affiliates, UNS Gas and UNS Electric, Inc. ("UNS Electric").

Q. Please describe your education and experience.

A. I received a Bachelor of Science degree in Aerospace Engineering from the University of Arizona in 1988 and a Master of Business Administration degree from the University of Arizona's Eller Graduate School of Management in 1999.

I was commissioned into the United States Navy in 1988 and served as a Nuclear-Trained Submarine Line Officer until 1993. From 1993 to 1994, I worked as a Process Engineer for Alcatel Telecommunications Cable in Roanoke, Virginia. From 1994 to 1995, I worked as the Instrumentation and Control Team Leader for Magma Copper Company in San Manuel, Arizona.

I was hired by TEP in 1995 as an Analyst in Product Planning and Development. In 1996, I moved into TEP's Wholesale Marketing Department as an Energy Marketer/Trader. I

was promoted to Supervisor of the area in 1999, Manager in 2001 and General Manager in 2003. I was promoted to my current position of Vice President of Wholesale Energy in 2007.

Q. Mr. Hutchens, what is the purpose of your Direct Testimony in this proceeding?

A. My Direct Testimony is policy-oriented. In my Direct Testimony, I support UNS Gas' request for an increase in rates by providing: (i) an overview of UNS Gas' operations; (ii) a summary of UNS Gas' rate request and the factors that have caused us to file our application at this time; (iii) the Company's recommended Fair Value Rate Base Rate of Return; (iv) an introduction into the rate design that UNS Gas is proposing in this case, including higher customer charges; (v) information on developer contributions, and (vi) identification of other UNS Gas witnesses and the topics that they will address in their respective testimony. Those witnesses will address many of these topics in greater detail.

II. OVERVIEW OF UNS GAS OPERATIONS.

Q. Please describe UNS Gas' service territories.

A. UNS Gas serves a growing base of customers in Mohave, Yavapai, Coconino, and Navajo Counties in northern Arizona, and Santa Cruz County in southeast Arizona. These counties comprise approximately 50% of the territory of the state of Arizona, with a population of approximately 799,000. A copy of a map depicting UNS Gas' certificated area is attached to my Direct Testimony as Exhibit DGH-1.

Q. Please provide a general description of UNS Gas' customers, Test Year and business operations.

A. UNS Gas is a gas distribution company and its customer base has grown to approximately 145,000 customers, 91% of which were residential customers, as of the end of the June 30,

2008 Test Year utilized by UNS Gas in this rate case filing ("Test Year"). During the Test Year, UNS Gas purchased or transported, on behalf of all of its customers, 27.62 billion cubic feet of gas.

Most of the gas distributed by UNS Gas in Arizona is procured from the San Juan Basin in the Four Corners region and delivered on the El Paso Natural Gas ("EPNG") and Transwestern Pipeline Company ("Transwestern") interstate pipeline systems. UNS Gas has firm transportation agreements with EPNG and Transwestern with combined capacity sufficient to meet its customers' demands.

III. SUMMARY OF UNS GAS' RATE REQUEST.

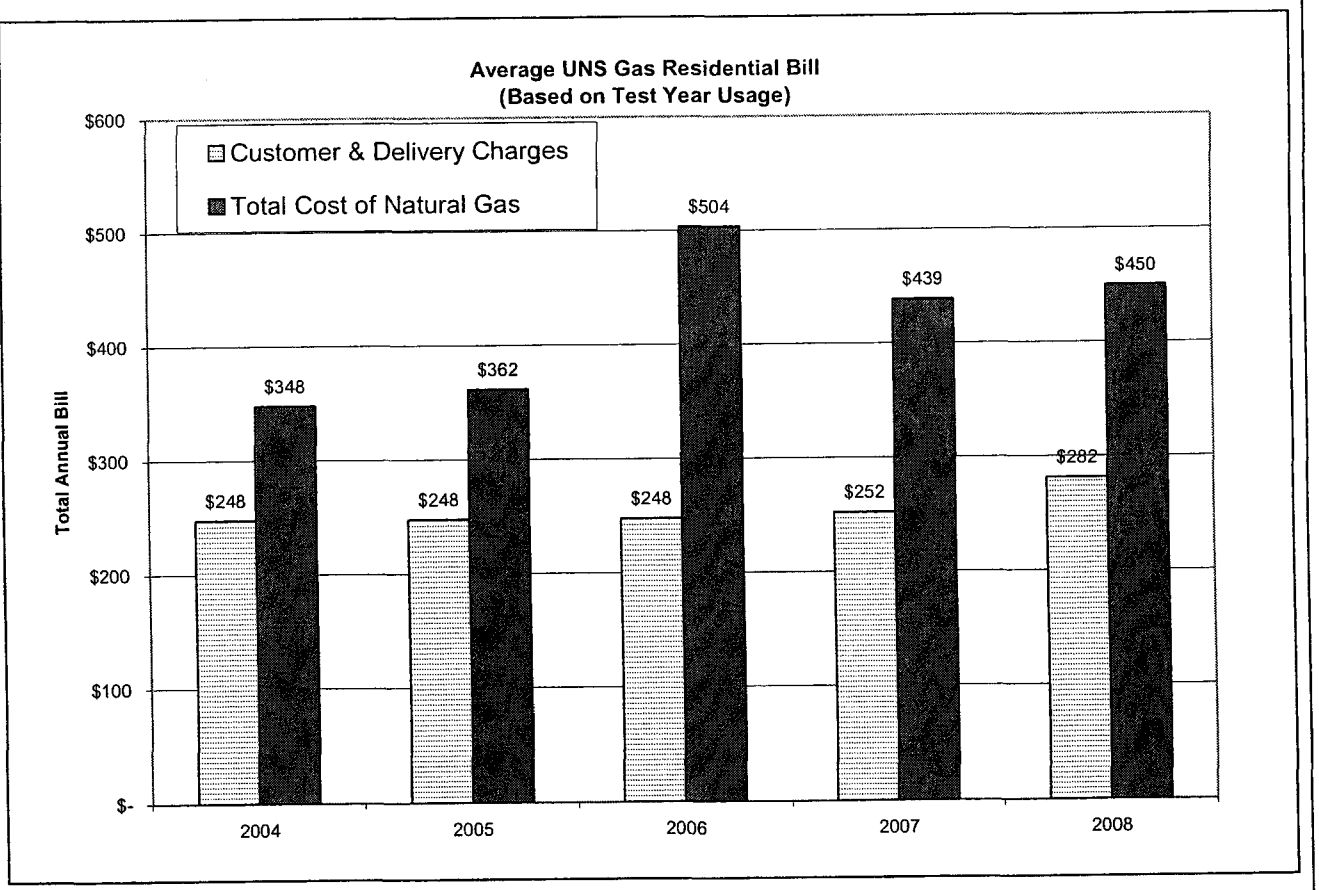
Q. Mr. Hutchens, what is UNS Gas requesting that the Commission do in this rate case?

A. In order to provide necessary rate relief, we are asking the Commission to authorize UNS Gas to increase its rates by $9.5 million. This would result in an average 6% increase to a customer's total bill compared to Test Year revenues, inclusive of gas costs. The effect on the fixed monthly and delivery charges on an average customer's bill will be an increase in those components of approximately 19% compared to Test Year revenues, excluding gas cost recovery. This is explained in greater detail in Mr. Dallas Dukes' Direct Testimony and Schedule A. We also request that the Commission adopt our proposed rate design.

Q. Do you have information showing a history of UNS Gas' bills since its acquisition from Citizens?

A. Yes. The graph below shows the two components of customer bills over time – customer and delivery charges (base rates), and the total cost of natural gas. These costs are based on the same monthly usage as the adjusted Test Year residential usage in this filing. It is important to remember that the total cost of natural gas is strictly a pass-through to

customers of actual costs incurred for acquiring the commodity and associated transportation. The Company has no control over the market cost of natural gas and does not make any profit on this portion of customers' bills; the market cost of natural gas currently accounts for nearly two-thirds of customers' bills. The only rate increase the Company has received related to its customer and delivery charges since it was acquired from Citizens was in the last rate case which went into effect in December, 2007 and accounts for increasing an average customer's bill by 5.7% compared to 2004. Over the same time period, the total costs of natural gas have increased 29% and accounts for increasing an average customer's bill by 17% compared to 2004.



Q. Please explain why UNS Gas is filing a request for an increase in rates at this time.

A. Even though UNS Gas recently received a rate increase, those rates are inadequate for the Company to recover its costs and earn a reasonable rate of return on its investment. Additionally, UNS Gas has also continued to experience growth in UNS Gas' service

territory, the related increase in capital expenditures and operating costs, as well as increases related to rising material and labor costs.

Since the end of the 2005 Test Year used in UNS Gas' recently completed rate case, UNS Gas has added over 5,000 customers. As of the end of the June 30, 2008 Test Year, UNS Gas had a customer base of 145,000. We project that the number of UNS Gas customers will increase by, on average, 2.5% annually. In order to meet its growth, UNS Gas has incurred, and will continue to incur, capital expenditures for items such as pipelines, meters and regulators. These items cost significantly more than they did even in 2005.

Also, from the end of the Company's last completed rate case, through the end of the Test Year, UNS Gas has put $54 million in capital expenditures into service to continue providing safe, reliable service to its customers. Operating expenses (excluding gas costs and income taxes) recovered through UNS Gas' current rates are $34.8 million, while operating expenses (excluding gas costs and income taxes) in this current rate filing are $37.7 million. UNS Gas' Test Year original cost rate base ("OCRB") is $182 million.

In summary, the main factors driving this rate case filing are: (i) current rates do not reflect substantial capital investment put into service since the end of the 2005; (ii) UNS Gas has continued to increase its investment in the gas properties attributable to upgrades to provide reliable service to existing customers and increased customer growth; and (iii) the Company's expense levels continue to increase due to rising material costs beyond its control.

IV. PROPOSED RATE OF RETURN ON FAIR VALUE RATE BASE.

Q. What is the Company proposing for its overall fair value rate of return?

A. UNS Gas is proposing a fair value rate of return ("FVROR") of 6.8% be applied to its fair value rate base ("FVRB") of approximately $256 million. The FVROR of 6.8% is significantly less than the FVROR (7.3%) that would result under the Commission's new FVROR mechanism set forth in the Chaparral City Water remand docket (Decision No. 70441 (July 28, 2008)). This FVROR will provide the Company with a realistic opportunity to earn its allowed return on equity ("ROE"). UNS Gas also believes that will allow it to support its creditworthiness and to attract capital on reasonable terms. Finally, due to the specific facts and circumstances of this filing in its entirety, the Company is proposing to forego the full FVROR in order to mitigate rate impact, in these challenging economic times. Mr. Kentton Grant addresses this proposal in more detail in his Direct Testimony.

V. CAPITAL SPENDING.

Q. Please describe the capital investment made by UNS Gas since the last rate case.

A. As I previously mentioned, UNS Gas has put an additional $54 million of capital investment into service on its distribution and service line facilities since the end of its last rate case Test Year. Roughly two-thirds of this significant investment has been related to growth in the Company's natural gas system in a number of service area communities in Arizona. The remaining one-third is attributable to UNS Gas' need to upgrade and reinforce its system for existing customers.

Q. Please describe the capital investment for the upgrade and reinforcement of the system.

A. It has been necessary for UNS Gas to acquire lateral pipelines from EPNG that supply the natural gas services to some of our distribution systems. These acquisitions gave the Company better control of system pressure and flow, allowing UNS Gas to provide safe, reliable, and continual service to its customers in a more cost effective manner than the alternatives. The expansion of UNS Gas' customer base also has required the Company to reinforce its distribution systems back at the receipt point to maintain reliable pressures and flow rates.

Q. Please describe how the capital investments have been utilized.

A. At the end of the Test Year, the Company had a total of approximately 2,893 miles of distribution mains and approximately 1,469 miles of services lines. During the Test Year, the distribution system was expanded to include approximately 75 miles of gas distribution mains and 18 miles of service lines. These capital investments were necessary to ensure UNS Gas' provision of safe, reliable and affordable service for its customers.

VI. DISTRIBUTION REVENUE STABILITY THROUGH A HIGHER MONTHLY CUSTOMER CHARGE.

Q. Mr. Hutchens, please describe UNS Gas' proposal for a higher monthly customer charge.

A. Mr. Bentley Erdwurm will address the specifics of our proposal. However, I will provide an overview of the Company's recommendation and request.

Currently, most of a gas utility's transmission, distribution and commodity costs are recovered on a volumetric basis. By that, I mean that the cost of acquiring natural gas and

delivering it to customers is recovered primarily through rates that were calculated on a basis of Test Year therm usage. If customer usage is similar to Test Year usage, costs are recovered as anticipated. However, higher than expected usage can increase margin revenues beyond anticipated levels, while lower usage can result in an under-recovery of the utility's costs.

In this case, UNS Gas requests the Commission to design rates that recover a greater share of the Company's fixed costs through slightly higher fixed customer charges. Under current rates, only 36% of residential revenue is collected through customer charges, although Mr. Erdwurm's class cost of service study indicates that customer charges should account for at least 65% of residential revenue.

Q. What are the advantages of this rate design that UNS Gas is proposing?

A. This approach is more economically sound than the current rate design, because it aligns rates more closely to the true costs of service. The cost of providing transmission and distribution service to individual UNS Gas customers varies little with usage. Yet, under the current rate structure, UNS Gas recovers the bulk of those fixed costs through volumetric charges. This forces higher usage customers – typically those living in colder areas of UNS Gas' service territory – to subsidize lower-usage customers. Although the Commission nominally increased the Company's monthly charge in our last rate case, significant subsidies still exist and the Company seeks to reduce those subsidies further. In this case, UNS Gas proposes to increase its monthly customer charges to help decrease those subsidies.

The rate design we have proposed relies on a higher average monthly charge to recover a larger share of the Company's fixed transmission and distribution costs, which are incurred regardless of whether the customer uses any gas. For example, owners of summer homes

would have to pay the true cost of having gas hooked-up and available, even if they do not use any gas during the high-usage winter months. Similarly, this proposal would ease the burden on customers in cold-weather climates who currently subsidize the fixed costs of customers in more temperate areas of UNS Gas' geographically diverse service territory. The more equitable rates that result from this change will help mitigate the subsidies inherent in current rates while sending much clearer price signals about the true costs of service.

Q. How will UNS Gas implement the rate design it is proposing?

A. Again, Mr. Erdwurm will provide greater detail on this rate design in his Direct Testimony, but the Company proposes an approach whereby monthly residential customer charge increases will be phased-in. During Phase 1 of the implementation, residential customer charges will increase from the current $8.50 per month to $10.00, when new rates become effective. One year after new rates become effective, Phase 2 will increase the residential customer charge to $12.00 per month. One year after Phase 2 implementation, Phase 3 will increase the residential customer charge to $14.00 per month. Even at $14.00 per month, the monthly residential customer charge will be well-below the cost-based customer charge supported by the class cost of service study ($18.15) described in Mr. Erdwurm's Testimony. With the Phase 3 residential customer charge of $14.00, only 50% of residential revenue will be collected through customer charges, as opposed to the 65% that would be collected with the cost-based $18.15 residential customer charge. The Company also proposes increases in the monthly customer charges for non-residential customers.

VII. REVISIONS TO PURCHASED GAS ADJUSTOR ("PGA").

Q. Is the Company proposing any changes to its PGA mechanism?

A. The only modification the Company is proposing is to the carrying cost rate for the PGA bank balance. We are proposing the rate be set at the actual carrying cost incurred by the Company – 3-month LIBOR plus 1%.

VIII. REVISIONS TO RULES AND REGULATIONS AND DEVELOPER CONTRIBUTIONS.

Q. Please describe the proposed changes to the Company's Rules and Regulations in this rate case filing.

A. UNS Gas is proposing some modifications to the Rules and Regulations in this docket, particularly with respect to service charges. Mr. Gary Smith sets forth those changes in detail in his Direct Testimony.

Q. Are you proposing any changes to the Company's customer contribution policies in this docket?

A. Yes, we are. UNS Gas is proposing a cost increase of $6.50 per foot (from $16.00 to $22.50, if the trench is provided by UNS Gas), or a cost increase of $4.50 per foot (from $12.00 to $16.50, if the trench is provided by the customer) to each new service line. The free footage allowance was eliminated in the Company's last rate case. We also have considered other alternatives for developer contributions as requested by the Commission in Decision No. 70011 (November 27, 2007). We believe that the prior elimination of free footage allowance and the increase of the per foot charge for line extensions proposed here help ensure that growth pays for growth. We are not, however, proposing any additional

hook-up fees in this rate case filing. Mr. Smith discusses the Company's proposals for increased contributions in greater detail in his Direct Testimony.

IX. DEMAND-SIDE MANAGEMENT AND LOW-INCOME PROGRAMS.

Q. Mr. Hutchens, has UNS Gas reevaluated its Demand-Side Management programs?

A. Yes. Ms. Denise Smith's Direct Testimony provides an overview of each UNS Gas Demand-Side Management ("DSM") program, including a status update on each program, and potential new DSM program additions that UNS Gas is reviewing for possible future implementation.

Q. Mr. Hutchens, is UNS Gas proposing to maintain its Customer Assistance Residential Energy Support ("CARES") program?

A. Yes, the Company is proposing to maintain the same basic monthly charge for CARES customers at $7, and the same non-commodity volumetric charge at $0.1770 per therm for the first 100 therms per month in the billing months of November to April. For all therms sold in excess of the initial 100 therms per month, the price is $0.3270 per therm. These charges cover non-commodity costs. The CARES customer charge has not increased since our acquisition of the Citizens system.

Q. Is UNS Gas proposing to expand its low-income assistance programs?

A. Yes. The Company is proposing to hold meetings of interested stakeholders to discuss modifications to the CARES program that could limit increases in gas commodity costs borne by these customers. If consensus can be reached, the Company will file testimony in support of the changes. The Company proposes that the CARES stakeholder group discuss expanding assistance beyond the 150% of poverty threshold applicable to CARES. Mr. Erdwurm provides greater detail on these topics in his testimony.

X. WITNESSES.

Q. Mr. Hutchens, in addition to you, who are the witnesses that are filing Direct Testimony for UNS Gas in this case?

A. UNS Gas is presenting the direct testimony of officers, managers and employees who have direct responsibility for the subject matter about which they will testify. The following individuals are presenting testimony in this proceeding:

Mr. Kentton C. Grant. Mr. Grant is the Vice President of Finance and Rates for UniSource Energy, TEP and its affiliates, including UNS Gas. Mr. Grant will testify about UNS Gas': (1) financial condition; (2) capital structure; (3) cost of equity; (4) cost of debt; (5) weighted average cost of capital; (6) ROR on fair value rate base; and (7) the financial impact of the Company's rate request. Mr. Grant also will address the modification of carrying cost rate for the PGA bank balance. Mr. Grant will sponsor the following schedules:

A-3	Summary of Capital Structure
A-4	Construction Expenditures and Gross Plant in Service
D-1 though D-4	Cost of Capital
F-1 though F-4	Financial Projections

Mr. Dallas J. Dukes. Mr. Dukes is the Manager of Rates and Revenue Requirements for TEP and its affiliates, including UNS Gas. He will testify concerning the UNS Gas income statement and adjustments to the income statement, as well as rate base and adjustments to rate base for regulatory purposes. He will also sponsor the following schedules:

A-1	Computation of Increase in Gross Revenue Requirements
A-2	Summary Results of Operations

A-5	Summary Changes in Financial Position
B-1 through B-5	Rate Base and Adjustments
C-1 through C-2	Income Statement and Adjustments
C-3	Gross Conversion Factor

Ms. Karen G. Kissinger. Ms. Kissinger is the Vice President, Controller and Chief Compliance Officer for UniSource Energy. She is also the Vice President and Controller of UNS Gas. She will testify concerning the Company's financial statements, income taxes, property taxes and ADIT within rate base. She will sponsor the following schedules:

E-1 through E-9	Financial Statements and Statistical Data

Mr. Gary Smith. Mr. Smith is a Vice President and General Manager of UNS Gas. Mr. Smith will discuss the following: (1) UNS Gas' low-income assistance programs; (2) revisions to the Company's Rules and Regulations and developer contributions; and (3) American Gas Association benefits. Mr. Smith will sponsor the following exhibits:

GAS-1(a)	Clean version of UNS Gas' Rules and Regulations;
GAS-1(b)	Redlined version of UNS Gas' Rules and Regulations;
GAS-2	Comments of Tucson Electric Power Company, UNS Electric, Inc. and UNS Gas, Inc. dated November 2, 2007, Docket Nos. E-00000K-07-0052 and G-00000K-07-0052;
GAS-3	Redlined version of Pricing Plan T-1 Transportation of Customer-Secured Natural Gas; and
GAS-4	Redlined version of Pricing Plan T-2 Transportation Service Using Dedicated Transmission Facilities.

Mr. D. Bentley Erdwurm. Mr. Erdwurm is the Lead Analyst in the Pricing and Economic Forecasting department for TEP and its affiliates, including UNS Gas. Mr. Erdwurm will testify about: (1) weather normalization; (2) the customer annualization adjustment; (3) the class cost of service study; (4) rate design and (5) the expansion of low-income assistance programs. Mr. Erdwurm will sponsor the following schedules and exhibits:

G-1 through G-7	Cost of Service
H-1 through H-5	Effect of Proposed Rate Schedules
DBE-1	Subsidy of Warmer Districts by Cooler Districts
DBE-2(a)	Clean version of Tariffs
DBE-2(b)	Redlined version of Tariffs

Ms. Denise Smith. Ms. Smith is the Director of Conservation and Renewable Programs at TEP, UNS Gas and UNS Electric. Ms. Smith will testify about UNS Gas' Demand-Side Management Programs.

XI. SUMMARY.

Q. Mr. Hutchens, please summarize the requests UNS Gas is making in this case:

A. We are requesting the following:

(1) An increase in base rates of $9.5 million, or approximately 6% over Test Year revenues, which will allow UNS Gas to recover its expenses and earn a reasonable return on its investment;

(2) Approval of the Company's requested rate design, which will result in an average 6% increase to a customer's total bill compared to Test Year revenues, inclusive of gas costs. The effect on the fixed monthly and delivery charges on an average

customer's bill will be an increase in those components of approximately 19% compared to Test Year revenues, excluding gas cost recovery; and

(3) Approval of requested changes to the Company's Rules and Regulations.

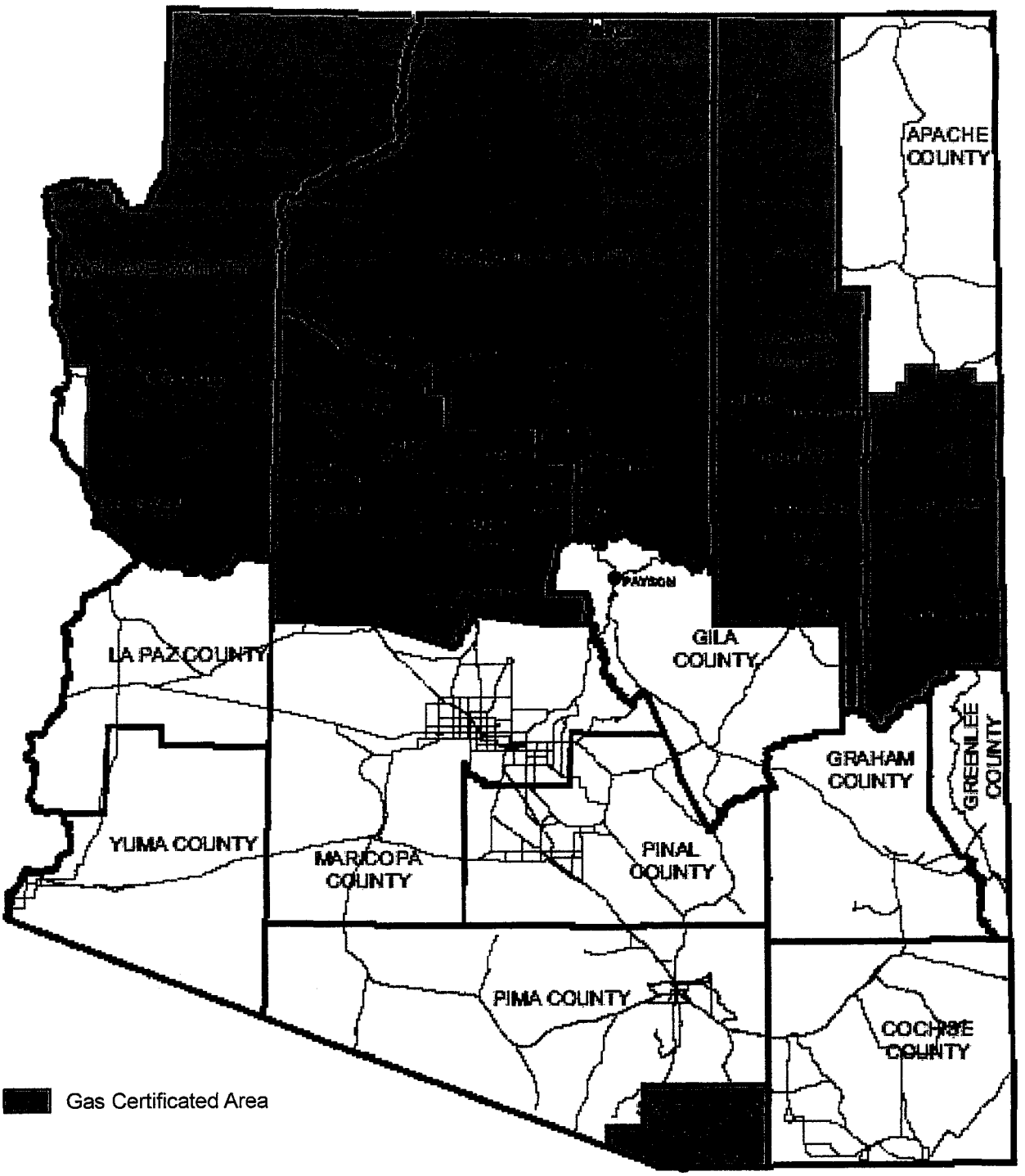
Q. Mr. Hutchens, does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT

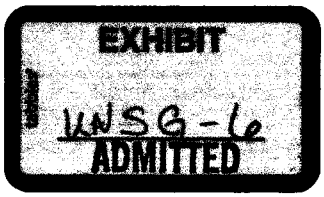
DGH-1

UniSource Energy Services
Gas Certificated Area



UniSourceEnergy
SERVICES

BEFORE THE ARIZONA CORPORATION COMMISSION



COMMISSIONERS
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BOB STUMP

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-04204A-08-0571

Rebuttal Testimony of

David G. Hutchens

on Behalf of

UNS Gas, Inc.

July 8, 2009

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is David G. Hutchens. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. Did you file Direct Testimony in this proceeding?

A. Yes, I did. In addition to my Direct Testimony, I will be adopting the Direct Testimony of Gary A. Smith in this case. Accordingly, my Rebuttal Testimony also addresses issues that arose in connection with Mr. Smith's Direct Testimony.

Q. What is the purpose of your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony addresses several areas. First, I provide an overview of UNS Gas' response to the Direct Testimony of Arizona Corporation Commission ("Commission") Staff, the Residential Utility Consumer Office ("RUCO") and the Arizona Community Action Association ("ACAA"). In particular, I will address our substantial concerns with the inadequate revenue requirements proposed by Commission Staff and RUCO. Second, I respond to the Direct Testimony of Commission Staff witness Ms. Rita R. Beale concerning gas procurement practices. Third, I respond to the Direct Testimony of Cynthia Zwick concerning the previous use of pay day loan offices as an option for paying customer bills. Specifically, I provide information regarding the transition to the use of Walmart stores for customer payments. Fourth, I discuss that the three UNS Gas office lobbies will no longer accept customer bill payments at those locations. Fifth, I discuss the Federal and State requirements for training of natural gas personnel, Pipeline Safety Manuals, Policies & Procedures, recordkeeping, and operations and maintenance for natural gas facilities. Finally, I request the Commission to grant the relief requested in

Docket No. G-04204A-08-0050 regarding current restrictions on the Company's use of certain third-party contractors. That relief will result in reduced expenses in the future.

II. REVENUE REQUIREMENT CONCERNS.

Q. What is UNS Gas' response to the revenue requirements proposed by Commission Staff and RUCO?

A. The revenue requirement proposals of Commission Staff and RUCO are significantly lower than the revenue requirement requested by UNS Gas. Upon review of Commission Staff's and RUCO's testimony, we conclude that this lower number is, in part, due to their deployment of calculations and methodologies that deviate from those recently approved and ordered by the Commission.

We have determined that if Commission Staff and RUCO had calculated UNS Gas' revenue requirement adhering to the methodologies approved by the Commission, their recommendations would be approximately $9 million and $5.4 million, respectively. The current recommendations of Commission Staff's and RUCO's consultants are not justified, are unreasonable and, if adopted by the Commission, will not allow UNS Gas an opportunity to earn a reasonable return on its investment.

Q. Please provide an example of how Commission Staff's and RUCO's recommendations differ from recent Commission decisions.

A. A good example is the "fair value" rate of return proposed by Commission Staff and RUCO. This issue has been thoroughly debated in a number of cases, and has resulted in at least two court appeals of Commission decisions. Rather than relitigate this issue, UNS Gas proposed a "fair value" rate of return calculation taken directly from a recent Commission decision based on Commission Staff's testimony in that proceeding.

In contrast to this, both Commission Staff and RUCO propose approaches that are inconsistent with recent Commission decisions on fair value. For example, Commission Staff witness Mr. Parcell's primary recommendation is to apply a zero percent (0%) return on the fair value increment – the same approach that the Commission rejected in the recent Southwest Gas rate order (Decision No. 70665). That approach resulted in a proposed return of only 6.03% here. Mr. Parcell's alternate recommendation, in which he applied a 1.25% return on the fair value increment, resulted in a return of only 6.37%.

RUCO's witness, Mr. Smith, declares (at RCS-2, Sch. A, page 2, col. A) that the fair value approach in one recent Commission decision is "way too high" for UNS Gas. Rather than looking to a recent Commission decision for guidance or providing any detailed analysis, Mr. Smith proposes a fair value return of 5.38% based on his own judgment, a value that is only 0.01% higher than the 5.37% return he obtained through a zero percent (0%) weighting of the Company's fair value rate base.

Neither Commission Staff nor RUCO provide any justification for their deviation from Commission-accepted methodologies for determining fair value. Accordingly, Commission Staff's and RUCO's fair value rate of return proposals should be rejected and UNS Gas' proposed rate of return of 6.8% should be adopted by the Commission.

Q. Please provide another example of how Commission Staff and RUCO have disregarded recent Commission rulings in their recommendations in this case.

A. Commission Staff's approach to customer annualization rejects the approach approved in Decision No. 70011 (November 27, 2007). This is especially odd because in that case Commission Staff argued strongly in favor of the traditional approach to customer annualization, and in Decision No 70011, the Commission agreed. Accordingly, UNS Gas employed the approach in its determination of its revenue requirement in this case.

However, Commission Staff now attacks the same traditional approach that it so strongly supported. The traditional approach has become no less traditional or appropriate in the short time since Decision 70011 was issued. [Commission Staff's deviation from the traditional approach results in a significant increase in operating revenue of $1,499,373, which Commission Staff proposes to use to decrease our revenue requirement by the same amount.] RUCO also ignored the customer annualization methodology used in Decision No. 70011 and simply rejected the Company's adjustment. Again, neither Commission Staff nor RUCO provide sufficient justification for their rejection of the Commission's approved approach for customer annualization. Consequently, their approaches should be rejected and UNS Gas' approach approved.

Q. Do you have another example of deviation by Commission Staff?

A. Yes, legal expense is another example. These costs are significant and ongoing, but they do vary from year to year with the ebb and flow of litigation and regulatory proceedings. Because of this variance, legal expenses often require normalization, as Commission Staff witness Dr. Fish acknowledges in his Direct Testimony at page 6, lines 6-7. In Decision No. 70011 (at page 20), the Commission approved UNS Gas' proposed legal expense after considering UNS Gas' historical costs for three years, and projected costs for one year. Unfortunately, Commission Staff and RUCO did not follow this approach in this case. Rather, they both propose significant reductions to legal expense based on a short-term, anomalous reduction in legal expense. Such anomalies are the very reason why legal expenses are normalized, as the Commission recognized in Decision No. 70011. Further, Commission Staff and RUCO fail to consider the legal costs associated with the recently filed El Paso Natural Gas Company rate case at FERC (Docket No. RP08-426), which is yet another rate case in a continuing series of such cases. This deviation resulted in a proposed reduction of that expense by $305,984 for Commission Staff and $217,674 for RUCO, which reduced our revenue requirement by the same amount. As is the case with

the prior examples cited, Commission Staff and RUCO have offered no explanation for their rejection of the Commission's prior treatment of these costs.

Q. UNS Gas has proposed some methods different from those approved in Decision No. 70011, correct?

A. Yes, there are a limited number of issues where UNS Gas has proposed a treatment different than the Commission used in our last rate case. However, each instance was justified and supported by a rationale that meets the concerns previously raised by the Commission. For example, in Decision No. 70011 the Commission rejected UNS Gas' request for post-test year plant, noting that we made no attempt to segregate revenue-producing plant from non-revenue producing plant. In this case, we directly responded to this concern by limiting our request for post-test year plant to non-revenue producing plant. Thus, our proposal is different than the one rejected by the Commission in Decision No. 70011 and is consistent with its rationale for the treatment of post-test-year-plant. Moreover, UNS Gas' proposal for non-revenue producing post-test year plant is consistent with a number of Commission decisions that have included such plant in rate base, including Decision Nos. 65350, 66849, 67279, 68176 and 68864. Thus our request is firmly grounded in recent Commission decisions.

Another example is our proposal to delay the deduction of customer advances from rate base, until the related plant funded by the advance is in service. Once the related plant is in service, the net result to rate base is zero – the plant funded by advances is not included in rate base. In rejecting this proposal, the Commission expressed concern that the proposal was linked to our CWIP proposal in that case, and that the problem was essentially of our own making and would not have occurred if we had not requested CWIP. In this case, we showed how this problem persists, and how the timing difference between recognition of advances and recognition of the related plant-in-service reduces existing rate base,

essentially wiping out existing shareholder investments. And while our proposal does differ from Decision No. 70011, it is grounded in traditional ratemaking principles.

Q. Do you believe Commission Staff's recommendations regarding Call Center expenses are fair?

A. No, I do not. Although Commission Staff does not appear to challenge that actual test year Call Center costs, it has recommended that the Call Center expense be reduced to the level in the prior rate case – a reduction of $484,798. Dr. Fish unsuccessfully attempts to justify (at page 27, lines 2-3) the reduction on the ground that the number of service orders for UNS Gas has decreased. Obviously, "service order" calls are not the only types of calls handled by the customer service representatives and are clearly inadequate as the only metric by which to judge the Call Center expense. In fact, call volume by UNS Gas customers for all types of calls has increased by over 150% since the prior rate case test year. Additionally, the duration of those calls has increased. Moreover, the last rate filing was for a 2005 test year and the level of expense in that test year was an annualized amount because the Call Center was only serving UNS Gas for part of the test year and was simply understated. Labor and other costs also have risen since the 2005 test year, something that Dr. Fish does not acknowledge. The test year costs for the Call Center are the actual allocated costs for UNS Gas during the test year.

Moreover, UNS Gas believes that the use of the Call Center, which is located in the State of Arizona, is the most efficient method for serving its 125,000 customers. UNS Gas does not believe a dedicated UNS Gas call center would result in lower costs. UNS Gas would need separate facilities, phone lines, computer systems, phone systems, call center employees and supervisors. The Company is performing in a more cost effective manner by partnering to share the significant fixed costs with two other utilities and should not be denied full recovery of the reasonable cost to serve the demands of its customers. It would

be a disservice to UNS Gas' customers to have to reduce the call center activity because of the decrease in expenses recommended by Commission Staff and RUCO.

Q. Do you have other concerns with Commission Staff's and RUCO's recommendations?

A. Yes, I am concerned by Commission Staff's and RUCO's recommended return on equity ("ROE"). Mr. Grant will address these issues in detail, but Commission Staff's recommendation is unrealistic. Commission Staff proposes a ROE of 10%. This is the same ROE approved for Southwest Gas in Decision No. 70665 – a case for which the hearing was held in June 2008, well before the current financial crisis reached its peak. It is the same ROE approved in the last UNS Gas rate order – a case where the extraordinary growth facing UNS Gas was an issue. With all of the uncertainty in the utility, construction and housing industries – and the overall slumping economy – Commission Staff's recommendation fails to recognize these more risky factors.

Q. What is the overall result of Commission Staff's and RUCO's approach?

A. Under Commission Staff's and RUCO's proposals, UNS Gas will never earn its authorized return, nor will the Company have even an opportunity to earn a reasonable return on its investments. Mr. Grant explains the impact of Commission Staff's and RUCO's recommendations, if adopted, on UNS Gas's financial condition – in summary, it is not good as it virtually assures that UNS Gas will continue to earn less than its authorized return. Thus, UNS Gas will have to consider filing back-to-back rate cases in a desperate attempt to "keep up". Such a result does not benefit anyone, especially our customers. The public interest is not served if the utility, Commission Staff and RUCO are embroiled in seemingly never-ending regulatory proceedings.

III. GAS PROCUREMENT ISSUES.

Q. Please provide an overview of the Direct Testimony of Commission Staff Witness Ms. Beale.

A. Ms. Beale conducted a prudency review of the Company's gas procurement operations. Her review encompassed gas procurement activities for the period of January 2006 through June 2008. Ms. Beale also reviewed the UNS Gas decision to terminate its full requirements service arrangement with BP Energy, the Company's purchased gas adjustor ("PGA") bank balances, pipeline capacity planning, and purchasing strategies and policies.

Q. Please summarize Ms. Beale's findings.

A. Ms. Beale found the purchase prices for natural gas to be reasonable and the quantity of pipeline capacity purchased to be prudent. She deemed the decision to terminate the agreement with BP Energy to be rational and identified several benefits to UNS Gas customers. Ms. Beale was able to reconcile over $240 million of PGA costs over the review period to within $10,000. Finally, Ms. Beale found the Company's strategies and policies to be generally reasonable.

Q. Did Ms. Beale offer recommendations in her Direct Testimony?

A. Yes. Ms. Beale made ten recommendations with respect to UNS Gas' procurement practices in her Direct Testimony; I will respond to each of those recommendations.

Q. Please comment on Ms. Beale's first and second recommendations that UNS Gas seek potential counterparties to optimize excess pipeline capacity and its use of Asset Management Agreements.

A. UNS Gas agrees to continue to seek opportunities to extract value from excess pipeline capacity. UNS Gas began using Asset Management Agreements in March of 2009 for

Transwestern pipeline capacity. Instead of executing a long-term Asset Management Agreement, UNS Gas limited the terms of its Agreements to single months so that other counterparties could be approached regarding the optimization of capacity. The result of this limited term was that UNS Gas received another offer in May of 2009 through a new Asset Management Agreement that increased the profit sharing percentage for UNS Gas. To date, Asset Management Agreements have been executed with two different counterparties. In order to increase the potential number of bidders to provide Asset Management Agreements, UNS Gas is developing its own preferred Asset Management Agreement for use in a more expansive request-for-proposal ("RFP") format.

Q. Please comment on Ms. Beale's third recommendation for UNS Gas to include supplemental pipeline commodity imbalance information its monthly PGA report to the Commission.

A. We concur that including the *UNS Gas Core Market/System Supply Imbalance Report* (the "Imbalance Report") may be useful information in reconciling PGA costs reported in the monthly report which UNS Gas files with the Commission. UNS Gas agrees to provide the Imbalance Report as a supporting document to its monthly PGA filing.

Q. What is your response to Ms. Beale's fourth recommendation to conduct gas procurement training to Energy Settlements and Billing personnel?

A. The Energy Settlements personnel have been a part of the BP Energy full requirements process since UniSource Energy Corporation acquired Citizens Utilities Company's ("Citizens") Arizona gas and electric assets. The amount and scope of transactions employed by UNS Gas became more transparent as the responsibility for optimization of UNS Gas' load shifted from BP Energy to internal personnel. Additionally, the particular Energy Settlements employees assigned to UNS Gas have shifted during the past few years. We agree with the recommendation to conduct training for the Energy Settlements

department employees on long-term hedging, day-ahead procurement, and pipeline capacity optimization.

Q. What is your response to Ms. Beale's fifth recommendation regarding the consideration of purchasing during traditional hurricane months?

A. We agree that UNS Gas should continue to evaluate gas purchasing opportunities during the traditional hurricane months. The Gas Price Stabilization Policy, while placing a hold on non-discretionary hedging during the months of August through October, does not prohibit discretionary hedging during those times. If it is determined that a hedge should be executed during those months, UNS Gas personnel may execute the hedge after receiving approval from the Risk Management Committee. This approval process is outlined in the Gas Price Stabilization Policy.

Q. What is your response to Ms. Beale's sixth recommendation that UNS Gas document instances when it deviates from its monthly forward hedge transaction plan?

A. We agree with the recommendation for UNS Gas to continue its policy of documenting occurrences of hedge plan deviations. The example given by Ms. Beale citing an instance of deviation from UNS Gas' forward monthly hedge plan was from an execution date of November of 2005. At that time, UNS Gas had already executed the non-discretionary hedges (under the legacy hedging policy from Citizens of three hedge events in January, March, and July) for 2005. The hedge instance in November of 2005 was a discretionary hedge meant only to hedge the balance of the winter season. The request for this discretionary hedge, and the Risk Management Committee approval, were documented as required.

Q. Please comment on Ms. Beale's seventh recommendation for the Gas Price Stabilization Policy to be updated with changes that occurred with the termination of the BP Energy agreement.

A. We concur that the Gas Price Stabilization Policy should be updated as changes resulting from the termination of the BP Energy agreement become evident. While UNS Gas made incremental changes to the Policy at the end of 2008, several operational changes have occurred with the distribution of duties that were still in flux at year-end. The policies are reviewed annually, however, and significant changes, such as the migration away from BP Energy, will produce effects that may require more frequent updates. Moving through the first full 12-month period post BP Energy termination, additional changes may be identified which require policy modifications.

Q. Please comment on Ms. Beale's eighth recommendation for the Gas Price Stabilization Policy to be updated at least annually.

A. We concur with this recommendation. Since adoption of the Gas Price Stabilization Policy, UNS Gas protocol has been to conduct a review of the policy at the end of each calendar year.

Q. Please comment on Ms. Beale's ninth recommendation that all individuals involved in gas procurement sign the Policy acknowledgement form.

A. We agree with the recommendation that all personnel involved in gas procurement sign an Acknowledgement Form. Personnel who will sign the Acknowledgement Form include those employees who perform tasks related to gas scheduling, transportation contracting, risk management and risk control.

Q. Please comment on Ms. Beale's tenth recommendation that there should be a single "owner" of the Gas Price Stabilization Policy.

A. We agree that a single person should be designated to modify the Gas Price Stabilization Policy. This ensures that proper control of updates and modifications is maintained.

IV. EXPLORING ALTERNATIVE PAYMENT METHODS.

Q. Has UNS Gas provided its customers with alternative ways in which to pay their bills, pursuant to Decision No. 70011?

A. Yes. In UNS Gas' last general rate case, concerns were raised about customers paying their gas bills at payday loan centers. As a result, UNS Gas reviewed other options by which its customers would be able to make cash payments. UNS Gas filed information related to "PayScan" with the Commission on February 22, 2008, and indicated that Circle K had been selected as the initial retailer to accept customer payments in Arizona. During the testing phase of the project, however, it was discovered that Circle K lacked the requisite software infrastructure to process payments. As a result, other retailer options were explored, and UNS Gas ultimately came to an agreement with Walmart.

Q. What is the current status of the UNS Gas' / Walmart payment arrangement?

A. This payment option became available to all UNS Gas, as well as Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNS Electric") customers in April of 2009; all Walmart sites in the state of Arizona will accept cash payments. The Company's web site has been updated to reflect this change and bill inserts were used to communicate the new payment option to customers.

UNS Gas has requested that check cashing and/or other outside payment center locations utilize signage, provided by UNS Gas, indicating that these locations will be independently

charging to process payments, effective July 1, 2009. Also effective July 1, 2009, UNS Gas has discontinued its payment of the fees the Company was covering associated with payments made at check cashing centers and/or other outside payment locations. UNS Gas chose this cut-off date because it wanted to provide customers sufficient notice of the payment change and to have a trial period to make sure the Walmart arrangement worked as anticipated.

V. UPCOMING UNS GAS LOBBY OPERATIONAL CHANGES.

Q. Could you please discuss certain upcoming operational changes regarding UNS Gas' office lobbies?

A. Yes. On October 1, 2009, UNS Gas will no longer accept customer bill payments at its lobbies located in Nogales, Kingman and Lake Havasu. However, those lobbies will still provide other customer services, such as assisting with billing questions or account inquiries. UNS Gas customers located in these areas will be notified of the change via bill inserts that will be included with customers' September bills. Additionally, signs will posted beginning September 1, 2009, at the Nogales, Kingman and Lake Havasu office lobbies, notifying customers of the change as of October 1st. UNS Gas will also notify Walmart stores of the possibility that customer traffic at Walmart for bill payments may increase as a result.

Q. How will UNS Gas customers be able to make payments after the lobby operational changes?

A. UNS Gas customers have multiple ways in which they can make payments, including via (i) US mail; (ii) the Company's drop boxes, located in certain grocery stores; (iii) the internet; (iv) SNAP (Sure No-hassle Automated Payment); (v) Walmart (cash and debit);

(vi) a customer service representative; (vii) IVR (Interactive Voice Response); and (viii) independent payment processors (such as America's Cash Express and Western Union).

VI. REGULATORY OPERATIONAL MANDATES.

Q. Is UNS Gas inspected by both the Federal and State Pipeline Safety Inspectors?

A. No. The Commission receives an annual Federal Certification from the U. S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") to act on behalf of PHMSA in the enforcement of Federal Pipeline Safety Regulations. The Commission has received a certification to enforce these regulations on both interstate and intrastate pipeline operators within the State of Arizona. The Commission has legislative authority to enforce Federal Pipeline Safety Laws pursuant to A.R.S. § 40-441 and 40-442.

Q. How is UNS Gas impacted by these requirements?

A. A very stringent set of Federal and State Pipeline Safety regulations dictate how UNS Gas must operate its facilities. UNS Gas must have Operations and Maintenance Procedures, Emergency Manuals, Construction Standards, Materials Manuals and Procedures, Employee Training Standards and Operator Qualification Training Programs. UNS Gas must devote substantial resources to complying with these extensive requirements.

Q. Has UNS Gas ever been assessed a penalty for violation of the Pipeline Safety Regulations during an inspection by the Commission?

A. No, we take these requirements very seriously – compliance is a top priority. UNS Gas has never been penalized for violating the Pipeline Safety regulations.

Q. Is the cost incurred by UNS Gas (i) to train its employees, and (ii) to maintain existing operation and maintenance, emergency and recordkeeping, required by the Commission Pipeline Safety regulations?

A. Yes.

VII. REQUEST FOR PROPOSED ORDER REGARDING THIRD PARTY CONTRACTORS.

Q. Do have any further testimony or requests you would like considered by the Commission?

A. Yes. On January 25, 2008, UNS Gas filed a request in Docket No. G-04204A-08-0050 for the Commission to waive the following requirements placed on the Company by Decision No. 66028: (i) refrain from the use of contract personnel for the performance of operation and maintenance functions, such as leak surveys and valve maintenance; and (ii) independently inspect all new construction work performed by contractor personnel regarding the installation of new service lines and main extensions. In its Application, UNS Gas noted that other local distribution companies use contract personnel in Arizona and that the Company's predecessor, Citizens, benefited from that practice as well.

Regarding the independent inspection of work performed by contractor personnel, UNS Gas states that since the acquisition it has entered into a sole contractor partnership with Northern Pipeline ("NPL") to comply more efficiently with the requirement; prior to the acquisition, Citizens was utilizing four (4) different pipeline contractors. Moreover, from its inception after Decision No. 66028, UNS Gas' Pipeline Safety Inspection Audits for the past five (5) years have been excellent. We anticipate that the elimination of the independent inspection requirement will help reduce operating expenses in the future.

Commission Staff responded to UNS Gas' Application on February 14, 2008. In its report, Commission Staff recommended that the Application for the waiver be approved. Citing UNS Gas' safety record, the progress of the Company beyond the transitional period of operations following the acquisition, and its operating history, Commission Staff stated that it believes these requirements are no longer necessary. Commission Pipeline Safety Staff has also reviewed, and supports, the Company's request for a waiver. However, the Commission has not yet taken action on those recommendations.

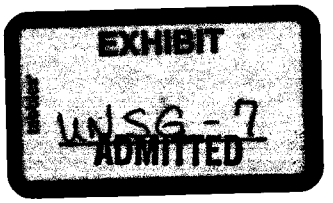
UNS Gas respectfully requests that the Commission approve a waiver of these requirements as part of its order in this case.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP



IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571

Rejoinder Testimony of

David G. Hutchens

on Behalf of

UNS Gas, Inc.

August 5, 2009

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is David G. Hutchens. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. Did you file Direct and Rebuttal Testimony in this proceeding?

A. Yes. I filed Direct and Rebuttal Testimony and have also adopted the Direct Testimony of Mr. Gary Smith.

Q. On whose behalf are you filing your Rejoinder Testimony in this proceeding?

A. My Testimony is filed on behalf of UNS Gas, Inc.

Q. Please summarize your Rejoinder Testimony?

A. First, I respond to certain incorrect statements and mischaracterizations by Staff witness Dr. Thomas Fish regarding the Company's capital investments made since December 2005, the end of last UNS Gas rate case. I also respond to Dr. Fish's continuing use of an estimated growth rate from last fall that simply no longer reflects reality.

Second, I accept the clarifications to the recommendations made by Staff witness Rita Beale in her Direct Testimony.

II. RESPONSE TO SURREBUTTAL TESTIMONY OF THOMAS FISH.

Q. What has Dr. Fish stated regarding the Company's capital investment?

A. Dr. Fish states (p. 13 of Surrebuttal) that:

It is clear that existing customers are being asked to pay for $36 million in capital investment that is not necessary for the Company's provision of service to them. That investment, according to the Company, was made to provide service to customers who do not exist and, according to the Company, may or may not exist at some time in the future.

Q. What is incorrect about these statements?

A. Dr. Fish misconstrues Company witness statements to come to the conclusion that somehow the Company has provided information that states the capital investment for growth was made for customers that do not exist. In essence, Dr. Fish appears to be saying these costs are not used and useful.

Q. How is this incorrect?

A. The Company's capital investments were made to serve *new*, not future customers. The amount attributed to growth in my Direct Testimony simply delineated the value of the plant put into service since December 2005 to connect to and serve new customers versus the capital spent on system improvements that benefited the existing customer base. New customers are real customers, not hypothetical future customers.

Q. Does Dr. Fish's Surrebuttal Testimony contradict Staff Witness Mr. Corky Hanson's Direct Testimony?

A. Yes. Dr. Fish implies that $36 million in capital investment by the Company was not used and useful and Mr. Hanson clearly states that it is used and useful.

Q. Is Staff recommending that an adjustment to rate base be made based on Dr. Fish's statements?

A. No. Staff has not recommended any adjustment to rate base as a result of Dr. Fish's statements.

Q. Are there other flaws to Dr. Fish argument?

A. Yes. Dr. Fish implies that a Company with no, or low, overall net customer growth cannot have growth related expenses. This is factually incorrect. A company could be adding new customers to its system and be losing an equal number of existing customers with the net result of "no growth". One can clearly see that a company in this situation would still have growth related investments. This may be particularly true where a company provides service to a broad, yet diverse, area.

Q. Is this what the Company is experiencing?

A. To some extent. We still have new customers hooking up to our systems but we are also losing a number of customers. The net of which is a lower overall customer growth rate and growth related expenses that are higher than would be expected if you looked at overall (or net) customer growth. Moreover, in this economy, lost customers can be particularly exacerbated in a situation where your service area includes a significant number of second homes or investor-owned homes.

Q. Dr. Fish continues to rely on a 2.5% growth estimate for UNS Gas from last fall. Is that reliance appropriate?

A. No. That estimate is outdated and reflected a 10-year average growth level as estimated last fall. It was not intended to reflect a short-term growth estimate. Even UNS Gas' one-year growth estimate from last fall (1.0%) ended up being significantly overstated to what occurred (-0.1%) Indeed, as set forth in Mr. Erdwurm's Rebuttal Testimony, there has been no short-term growth in our service area. Moreover, recent growth estimates have decreased significantly. For example, UNS Gas does not expect more than a 0.6% average annual growth over the next three years. But that number could change significantly again,

depending on a variety of factors. Such variability is one reason why growth estimates simply are inappropriate for customer annualization calculations.

III. RESPONSE TO SURREBUTTAL TESTIMONY OF RITA BEALE.

Q. Do you agree with the clarifications Ms. Rita Beale provided in her Surrebuttal Testimony regarding her Direct Testimony Recommendations?

A. Yes. Her clarifications fill in the gaps in my understanding of her recommendations and will be implemented by the Company.

Q. Does this conclude your Rejoinder Testimony?

A. Yes, it does.

EXHIBIT
UNSG-8
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-____

Direct Testimony of

Gary A. Smith

on Behalf of

UNS Gas, Inc.

November 7, 2008

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Exhibits

Exhibit GAS-1(a)	Clean version of UNS Gas' Rules and Regulations
Exhibit GAS-1(b)	Redlined version of UNS Gas' Rules and Regulations
Exhibit GAS-2	Comments of Tucson Electric Power Company, UNS Electric, Inc. and UNS Gas, Inc. dated November 2, 2007, Docket Nos. E-00000K-07-0052 and G-00000K-07-0052.
Exhibit GAS-3	Redlined version of Pricing Plan T-1 Transportation of Customer-Secured Natural Gas
Exhibit GAS-4	Redlined version of Pricing Plan T-2 Transportation Service Using Dedicated Transmission Facilities

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Gary A. Smith. My business address is 2901 West Shamrell Blvd., Suite 110 Flagstaff, Arizona 86001.

Q. What is your position with UNS Gas, Inc. ("UNS Gas" or the "Company")?

A. I am employed by UNS Gas as Vice President and General Manager of Gas Operations.

Q. What are your duties and responsibilities?

A. I am responsible for directing the operations of UNS Gas. UNS Gas serves a growing base of customers in Mohave, Yavapai, Coconino, and Navajo Counties in northern Arizona, and Santa Cruz County in southeast Arizona. These counties comprise approximately 50% of the territory of the state of Arizona, with a population of approximately 799,000. My primary duties include oversight of the operations, maintenance, construction, and expansion of UNS Gas' systems. I also have management responsibility for UNS Gas employees.

Q. Please outline your educational background.

A. I have a Masters degree in Information Technology from the University of Phoenix and a Bachelor of Science degree in Civil Engineering from Arizona State University. I also have Associate of Arts degrees in Fire Science from Mesa Community College in Arizona and Emergency Medical Training from Monroe County Community College in Michigan.

Q. Please state your work experience.

A. I have 30 years of public utility experience, including 26 years of senior management experience. I have been with UNS Gas (or the "Company") since August 11, 2003. Prior

to that, I worked at Citizens Communications Company ("Citizens") as Vice President and General Manager, Arizona Gas Division for six years. Prior to my position at Citizens, I worked at the Arizona Corporation Commission ("Commission") for 19 years. During my tenure at the Commission, I served as Chief of Safety (1988-1998) and Chief of Pipeline Safety (1983-1988).

Q. What is the purpose of your testimony in this proceeding?

A. I will provide information on (i) UNS Gas' low-income assistance programs, (ii) the Company's proposed changes to its Rules and Regulations, (iii) the benefits of the American Gas Association dues, and (iv) the Commission's request for information concerning developer contributions.

II. LOW-INCOME ASSISTANCE PROGRAMS.

Q. Please describe the current CARES program.

A. Qualifying residential CARES customers are assessed a discounted Minimum Customer charge of $7.00 per month throughout the calendar year. Additionally, CARES customers receive a $0.15 per therm monthly discount on the first 100 therms used during the winter billing months of November through April. The Company promotes the CARES discount program by placement of a bill insert that is received by all residential customers, including, radio and newsprint.

Q. How does a residential customer qualify for CARES discounts?

A. The customer completes a CARES Discount application. These applications are available at the local assistance agencies as well as from the Company. To be eligible for the discount, the customer must have a gas account in their name and a combined household income at or below 150% of the federal poverty level.

Q. Mr. Smith, is UNS Gas proposing to maintain its CARES program?

A. Yes, the Company is proposing to maintain the same basic monthly charge for CARES customers at $7, and the same non-commodity volumetric charge at $0.1770 per therm for the first 100 therms per month in the billing months of November to April. For all therms sold in excess of the initial 100 therms per month, the price is $0.3270 per therm. These charges cover non-commodity costs. The CARES customer charge has not increased since our acquisition of the Citizens system.

Q. Is UNS Gas proposing to expand its low-income assistance programs?

A. Yes. The Company is proposing to hold meetings of interested stakeholders to discuss modifications to the CARES program that could limit increases in gas commodity costs borne by these customers. If consensus can be reached, the Company will file testimony in support of the changes. The Company proposes that the CARES stakeholder group discuss expanding assistance beyond the 150% of poverty threshold applicable to CARES. Mr. Erdwurm provides greater detail on these topics in his testimony.

Q. Do CARES program participants enjoy any other benefits?

A. Yes, CARES customers may also be eligible for assistance through our Warm Spirits Program and our Low-Income Weatherization Program. Ms. Denise Smith's Direct Testimony provides more detail on the Weatherization Program.

Q. Is the Company proposing any changes to its Warm Spirits Program?

A. The Company is proposing one change to its Warm Spirits Program. UNS Gas currently offers two options for contributing to the Warm Spirits Program; customers can either (i) pledge a fixed amount which is added to their monthly utility bill, or (ii) make a random contribution by entering the contribution amount on their bill payment coupon and include

the contribution amount when paying their monthly bill.[1] UNS GAS proposes to add a 'round-up' option for customers. Customers signing up for the 'round-up' option would see their monthly bill rounded up to the next even dollar. The difference between their billed amount for actual usage and the next even dollar would be their contribution to the Warm Spirits Program. In addition, the Company will continue to match aggregate customer contributions up to $25,000 annually.

There have also been changes to the way UNS Gas is administering the program. UNS Gas is working with the Arizona Community Action Association ("ACAA") to assist in distributing the contributions. The total amount of Warm Spirit Contributions is dispersed to the ACAA on a quarterly basis. As an independent agency, the ACAA identifies the eligible assistance agencies, determines which agencies should receive funding, and ultimately disperses the specific amounts to be given to individual agencies. The ACAA then distributes those funds to the respective assistance agencies within the same community from which the contributions were received. This process ensures that UNS Gas customers' contributions remain in the community to help their less fortunate neighbors.

Q. How does the Warm Spirits program assist low-income customers?

A. As previously mentioned, the assistance agencies receiving the Warm Spirits funds determine how the funds are distributed to our customers. These agencies provide the necessary funds to avoid non-pay disconnection of service and will also assist customers by providing the required funds for connection or re-connection of service.

[1] UNS Gas had already complied with the requirement from Decision No. 70011 before the Decision was approved.

III. RULES AND REGULATIONS.

Q. Is UNS Gas proposing changes to its Rules and Regulations?

A. Commission Decision No. 70011 (November 27, 2007) approved substantial changes to UNS Gas' Rules and Regulations. In this Application, UNS Gas is proposing a few substantive updates to some of these Rules and Regulations, as well as other tariffs, and is seeking Commission approval of these changes.

Q. Please describe the proposed changes in this rate case.

A. UNS Gas is proposing only a few substantive changes to its Rules and Regulations at this time. I will discuss the following changes in greater detail later in my testimony:

- Section 2 – Add definitions for "Elderly", "Excess Flow Valve", "Service Transfer", "Special Call Out" and "Trip Charge". Delete the definitions of "Senior Citizen" and "Working Hours". Clarify the definition of "Service Reconnection Charge";
- Section 3 - Clarify the applicability of service establishment, reestablishment and reconnection charges, as well as the charges for service transfers and multiple attempts to connect;
- Section 6 - Increase the charge for service line establishments from $16.00 per foot to $22.50 per foot. For those customers who perform the trenching work, the charge for service line establishments will increase from $12.00 per foot to $16.50 per foot;
- Section 8 - Delete the "Table of Atmospheric Pressure Bases" by geographical zone descriptions in favor of a more simplified version that shows the atmospheric pressure bases within specific elevation ranges; and
- Section 17 - Add the Statement of Additional Charges to the end of the Rules and Regulations.

Q. Why is the Company proposing changes in Section 2, "Definitions"?

A. The definitions for "Service Transfer", "Special Call Out" and "Trip Charge" were necessary because of the addition of the Statement of Additional Charges and the need to explain those charges. An "Excel Flow Valve" definition was added. Language was also added to the "Service Reconnection Charge" definition to clarify the charges that would be incurred if this charge was applied. The definition of "Working Hours" was deleted because it is not used in the document. The definition of "Senior Citizen" was replaced by the definition of "Elderly".

Q. What is the basis for proposing the change to the table of atmospheric pressure bases?

A. As reflected in Commission Decision No. 68113 (September 9, 2005), the Rules and Regulations were updated to provide more detailed information regarding the conversion of one hundred cubic feet (volume of gas) to therms (energy content) used for customer billing purposes. This update included a table of atmospheric pressure bases related to each town and their respective elevation bands. Listing these elevation bands by geographical zones is redundant; the appropriate atmospheric pressure to apply is determined by the elevation band. Thus, the town is irrelevant; the determining factor to ascertain the appropriate atmospheric pressure to apply is the elevation band. Since the point of elevation at which a customer's service is provided is used to ascertain the applicable atmospheric pressure, the table was streamlined to better highlight this determinant.

Q. Why add the Statement of Additional Charges to the Rules and Regulations?

A. UNS Gas believes that having these charges listed in one, easy-to-find location within the Rules and Regulations, as opposed to a separate Company Pricing Plan, will make it easier for its customers and future customers to ascertain which charges may apply to them.

These charges were in Pricing Plan MISC-1 before, which only listed them but gave no explanation for the charges. By adding the Statement of Additional Charges to the Rules and Regulations, the Company and the Customer have the explanation for the charges as well as the charges themselves listed in one place.

Q. Please describe the proposed charges listed in Section 17 of the Statement of Additional Charges.

A. UNS Gas is proposing the following fees, which have increased due to the rising costs for these particular services:

• Service Transfer	$20.00
• Collection Fee	$20.00
• Customer-Requested Meter Reread	$20.00
• Multiple Attempts to Connect	$20.00
• Service Establishment, Re-establishment or Reconnection	
During Regular Business Hours	$35.00
After Normal Business Hours (same day request scheduled)	$50.00
• Special Call Out (Minimum one (1) hour)	
After Normal Business Hours - per hour	$70.00
• Customer Requested Meter Test	$90.00
• Late Payment Finance Charge	1.5%
• Interest on Customer Deposits	One-year Treasury Constant Maturities rate

Additionally, UNS Gas is proposing to reduce the NSF check charge from $15.00 to $10.00.

Q. Is a copy of the proposed modifications to the Rules and Regulations attached?

A. Yes, both clean and redlined copies of the revised Rules and Regulations are attached as Exhibits GAS-1(a) and GAS-1(b), respectively, to my Direct Testimony.

Q. Is UNS Gas proposing to make any changes to Pricing Plan T-1 Transportation of Customer-Secured Natural Gas ("Pricing Plan T-1") and Pricing Plan T-2 Transportation Service Using Dedicated Transmission Facilities ("Pricing Plan T-2")?

A. Yes. The T-1 and T-2 Pricing Plans apply to certain large commercial customers. Currently "Balancing", found under the section heading "Operating Procedures" in both Pricing Plan T-1 and Pricing Plan T-2, states:

> Customers are provided a monthly operating window, under which the Customer's cumulative imbalances must be within plus or minus 5 percent (+/- 5%) of the month's total of daily scheduled transportation quantities, plus any Company-approved imbalance adjustment quantity, or 10,000 therms, whichever is greater.

UNS Gas is proposing to change the 10,000 therm threshold to 1,500 therms. The 5 percent (5%) allowance is not being changed. The redlined versions of Pricing Plan T-1 and T-2 are attached as Exhibit GAS-3 and Exhibit GAS-4, respectively to my Direct Testimony.

Q. Why are you making this change?

A. Currently UNS Gas' monthly imbalance cash out threshold under the El Paso Natural Gas ("EPNG") tariff is only 2,000 decatherms (Dth) or 20,000 therms. Allowing each transportation customer a monthly threshold that is one-half of the monthly threshold that UNS Gas must adhere to for its entire system under EPNG can place additional operational constraints and/or penalties on UNS Gas. UNS Gas currently has eight (8) transportation customers that are managed by third party suppliers who are responsible for managing

those customers' monthly imbalances. Reducing the monthly threshold to 1,500 therms is a more reasonable volume. This change in the language also makes UNS Gas' monthly operating window consistent with the monthly operating window allowed by other gas distribution utilities in the state.

Q. Is the Company proposing any changes to monthly residential customer charges?

A. Yes, the Company is proposing a phased-in increase in residential customer charges to levels more reflective of the true customer-related costs. During Phase 1 of the implementation, residential customer charges will increase from the current $8.50 per month to $10.00, when new rates become effective. One year after new rates become effective, Phase 2 will increase the residential customer charge to $12.00 per month, and one year after Phase 2 implementation, Phase 3 will increase the residential customer charge to $14.00 per month. Mr. Erdwurm's Direct Testimony provides more detail on this proposal.

IV. AMERICAN GAS ASSOCIATION ("AGA") BENEFITS.

Q. Does the Company use a cost/benefit analysis in determining the value of AGA's services?

A. Yes. In 2006, the AGA's programs, services and advocacy efforts provided its members with $479 million in outright savings or avoided costs. The AGA collected under $18 million in membership dues which resulted in more than a $27 return on every $1 in paid AGA dues.

Q. Is UNS Gas requesting recovery for the AGA's marketing and lobbying activities?

A. No. In accordance with previous Commission decisions, UNS Gas is not requesting recovery of the dues associated with marketing and lobbying activities.

Q. What amount of AGA dues is the Company requesting recovery of?

A. UNS Gas is requesting the recovery of $45,964 related to AGA dues. As detailed below, the information and services UNS Gas received from the AGA far exceeds this cost.

Q. Would you please describe some of AGA's activities and how these activities benefit, either directly or indirectly, a member company's customers?

A. Yes. AGA conducts hundreds of operating and engineering activities to improve the safety, efficiency and productivity of member companies' engineering and operating functions. Some recent examples of AGA's operating and engineering activities include:

(1) Over all, the safety records of natural gas utilities are outstanding and they continue to improve. To encourage greater improvement in the safety of the natural gas delivery system, AGA hosted a Safety Leadership Summit in late 2007 for its members to come together and discuss the state of the natural gas industry in four critical areas of safety:

- Employee Safety;
- Utility Contractor Safety;
- Pipeline Safety; and
- Public Safety.

(2) AGA publishes the Gas Piping Technology Committee ("GPTC") Guide periodically. This GPTC Guide is prepared by safety experts from gas distribution and transmission companies, federal and state regulatory agencies, manufacturers and industry consultants and is updated when new materials and procedures are approved for use. UNS Gas uses the GPTC Guide to design and select piping material types. This Guide has saved UNS Gas time and some of the expense of designing and developing its systems, and insures standardization.

(3) The Operating and Engineering Committee helped initiate a campaign to increase awareness among contractors and excavators about the damage that can be done to buried pipeline mains as a result of their activities. AGA is a supporting sponsor of this National Program known as the "Common Ground Alliance." Two out of three reportable incidents on these mains are a result of third-party excavators. Most incidents occurred because the utility was not notified that work was about to be done or given the opportunity to mark the gas line. As a result of this effort, AGA has helped to raise public awareness of the importance of damage prevention programs and has provided a forum for states to better address this issue. UNSG continues to work to improve communication with excavators and reduce these incidents which are costly in terms of injuries and repair expenses, and which, for the most part, are avoidable.

(4) The AGA has taken the lead in developing easy-to-use personal computer software to deal with a variety of operating and/or engineering issues faced by gas companies. The cost of these programs to member companies is minimal in relation to costs saved, specifically development and labor costs. So far, software programs have been developed in the following areas:

- Gas Measurement - performs orifice flow and super compressibility calculations; and
- Gas Properties – Calculates natural gas speed of sound, critical flow coefficient and other thermodynamic properties.

(5) The AGA updates "Report No. 3, Orifice Metering of Natural Gas." This Report is a standard reference in gas contracts. Improved measurement accuracy increases UNS Gas' efficiency and UNS Gas' ability to pass any savings on to its customers.

(6) The AGA's Plastic Materials Committee evaluates the use of plastic materials and new fabrication techniques for gas piping systems. This Committee publishes the AGA Plastic Pipe Manual for Gas Services, which includes the latest information on plastic materials, piping components and design, as well as installation procedures covered under Federal and State regulatory codes and standards for natural gas distribution piping systems. Through the use of this information, member companies can more quickly, confidently and safely increase the use of more cost-effective plastic materials.

(7) The AGA Best Practices Program for Gas Distribution is an effort to identify procedures of superior performing gas industry companies and innovative work practices that can be used to improve participants' operations. The program focuses on improving the safety and efficiency of gas distribution system construction, maintenance, operation and inspection. Information is made available regarding a number of operational improvements in areas such as street repairs, safer trenchless technology and automated dispatching. Members have documented millions of dollars in savings from participation in this program, which in turn translates to lower costs for the customer.

(8) The Operating and Engineering Committee has developed a large number of manuals and textbooks that are essential in the day-to-day operation of gas utilities. An excellent example is the Gas Engineering and Operating Practices Services. This 11-book series has become the authoritative work on gas utility engineering. AGA manuals are incorporated by reference in the Commission's Pipeline Safety Regulations (at A.A.C. R14-5-202.R., for example).

(9) The AGA's Operating Section continues to provide support to its members who seek industry information on a variety of operations and engineering issues. The SOS Program is a resource for AGA members who have the need to query others on a particular subject. The SOS program is a simple and effective way for members to better understand how others are addressing a particular issue/challenge. Recent SOS requests include member-initiated surveys on the following topics:

- Oversight of, and quality checks on, contractors that perform locating services;
- Security metrics;
- Excavation and backfill practices around transmission lines;
- Third party damage claims;
- Gas odorization practices;
- Budget practices used for forecasting operations & maintenance workload;
- Elevated delivery pressure; and
- Right of Way acquisition.

These are just a few of the many operating and engineering-related projects that benefit a member company and its customers. While all of these benefits cannot necessarily be quantified in specific dollar amounts, it is clear that AGA activities provide significant benefits to customers in terms of improving the reliability and safety of UNS Gas' distribution system.

Q. Do you represent UNS Gas on any of the many AGA Committees?

A. Yes. I am a member of the AGA Operations and Engineering Committee. This group focuses on five areas:

- Safety, Security & Environment;
- Distribution and Transmission Engineering, Construction & Maintenance;

- Supply Management-Supplemental Gas;
- Gas Measurement; and
- Inside Building Operations.

I am the Primary Sponsor for AGA's Building Energy Codes and Standards Committee, a sub-committee within the Operations & Engineering Section.

V. GROWTH, INCREMENTAL COSTS FOR NEW SERVICE AND MAIN LINES, AND HOOK-UP FEES.

Q. Why are you providing a discussion regarding growth and hook-up fees?

A. In Commission Decision No. 70011 (November 27, 2007), the Commission directed UNS Gas to investigate the issue of developer contributions and to present alternatives that would hold harmless existing customers while requiring greater contributions from developers to ensure that costs associated with new customer growth would be borne by those new customers.

Q. Did UNS Gas explore the hook-up fee issue, as contemplated in Decision No. 70011?

A. Yes. UNS Gas participated in a Commission workshop regarding hook-up fees on October 18, 2007. At the conclusion of that workshop, the parties were asked to provide written comments by November 1, 2007 regarding the various issues that were raised and questions that were posed. UNS Gas, as well as Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNS Electric") (hereinafter referred to collectively as "the Companies"), filed collective comments on the issues and questions raised by the Commission; a copy of those comments is attached as Exhibit GAS-2. In general, the Companies believe that properly-crafted line extension policies and the Incremental Cost Study ("ICS"), coupled with rates that are based on relevant costs of service, will ensure

that new customers pay an appropriate amount of cost through some combination of contributions-in-aid-of-construction ("CIAC"), customer advances and rates.

Q. Are hook-up fees the most effective method to ensure that growth pays for growth?

A. No, UNS Gas does not believe that hook-up fees will ensure that growth pays for itself. Hook-up fees could potentially lead customers to choose other resource alternatives, such as electricity or propane, over natural gas. To the extent that hook-up fees will require customers to bear a greater up-front investment than under current practices, customers may be forced to choose where to invest their limited cash. A customer may invest (pay any hook-up fee and other connection costs) in just one energy source; there simply may be nothing left for secondary sources like natural gas. In general, customers continue to choose natural gas where available because the per therm cost of propane is significantly higher than the cost of natural gas. However, the larger the up-front fee for natural gas, the greater the chance that customers will not invest in natural gas as a second energy source. To avoid the up-front fee for natural gas, customers may choose propane, even though some home-buyers in towns and cities with gas distribution systems (at least in some areas) may consider propane an inferior alternative. The up-front cost to install propane would be low compared to the cost to install natural gas service if natural gas hook-up fees are mandated.

Higher up-front costs to install natural gas also may result in reduced gas system growth and a reduction in customer choice and energy diversity in Arizona. In the past, the Commission Staff has promoted fuel diversity because of the relative efficiency of gas water heaters, clothes dryers and other end-uses, and because of the environmental advantages of burning natural gas as compared to solid fuels such as coal. Moreover, future customers without energy choices may be more exposed to price swings in the electric market. Long-term increased use of electricity can put pressure on existing electric

distribution and regional transmission systems which may increase the cost of electric delivery. Clearly, customers benefit from having more choices.

Q. How do hook-up fees violate the tradition of system-wide rates in cases where the fees move beyond costs that are directly assignable to new customers?

A. One can argue that additional expenditures for supporting facilities that will serve all or most customers, such as the new backbone distribution serving all customers or the bulk of customers, should not be recovered disproportionately from new customers through hook-up fees. For example, the need to upgrade a distribution system serving an area from a 2-inch to a 6-inch line, or to connect radial systems to form a looped system, is driven by increased total load (attributable to both new and old customers) and a desire to ensure reliable delivery of natural gas to all customers in that region, particularly under extreme conditions. Investments of this nature generally cannot be tied to any single customer, although they may be tied to a region or district. In the absence of regionally established tariffs, the Company recovers these costs as part of its standard sales rates. Traditionally, all customers within a class pay the same prices, and there is no penalty for being a "new" customer. An existing customer, after all, could choose to leave the system instead, thus freeing up resources and deferring the backbone distribution improvements. Prospective incremental costs can be reduced either when a potential new customer chooses not to move in, or when an existing customer chooses to leave. An existing customer should not be entitled to preferential treatment in the allocation of costs based on when the customer connected to the system.

Q. Please describe in more detail the recovery of distribution costs, and explain why the current methodology is an appropriate way to ensure that new customers pay a proper share of costs.

A. There are different methods of assigning and recovering costs incurred for capital investments in UNS Gas' system.

First, UNS Gas recovers the cost of all new service lines providing natural gas directly to customer homes or places of business through the execution of a Line Extension Agreement. This Agreement requires that the customer pay a fixed per-foot amount for service lines installed on the customer's property, as well as any additional actual incurred costs such as relocation of landscaping. This approved per-foot amount, as part of the Company's Rules and Regulations in Section 6, includes the cost of construction, supervision, planning, and transportation so that the new customer bears all costs associated with the service installation. The Company proposes in this rate proceeding to increase the per-foot amount to recover recent increases in materials cost, as well as labor costs.

Second, UNS Gas has eliminated all 'free footage' in service line installations in an effort to better link cost recovery to cost causation.

Third, UNS Gas' request directly recovers the costs incurred for: (i) locating any private property buried facilities (e.g., lawn sprinklers) for every new installation; and (ii) installing the mandatory Excess Flow Valves ("EFV").

Finally, UNS Gas applies the Commission-approved ICS methodology (A.A.C. R14-2-307.C) to assign costs for facilities upstream of new customer premises where the cost can be exclusively assigned to new customers. Generally this applies to the backbone

distribution system exclusively serving new customers where the cost of facilities serving a unique development of homes can be isolated to the particular developer or builder. Under this methodology, UNS Gas determines its maximum allowable investment, pursuant to the ICS, that will support UNS Gas' authorized rate of return, assuming that additional "common" backbone distribution costs (i.e., serving all customers) are not considered. The ICS approach requires the customer (usually the developer or builder) to contribute the amount of all actual construction costs in excess of this allowable investment. As actual customers connect to the new backbone, the initial developer may receive a partial refund. However, after five years, any refunds cease.

UNS Gas establishes an ICS for each unique district based on the average expected margin revenue within that district. Under this methodology, the builder, developer or new customer bears an appropriate share of cost, given the location of the new load.

Q. Please provide more detail on the costs that UNS Gas collects from new customers through the Line Extension Tariff.

A. The costs to install the customer service line from the private property line (street curb) though the private property to the building wall are reviewed and updated on an on-going basis and are incorporated into the Line Extension section of UNS Gas' Rules and Regulations. UNS Gas is proposing a cost increase of $6.50 per foot (from $16.00 to $22.50, if the trench is provided by UNS Gas), or a cost increase of $4.50 per foot (from $12.00 to $16.50, if the trench is provided by the customer) to each new service line, and additional charges that are part of providing the new customer with gas service. The total customer contribution as proposed by UNS Gas based on an average service length of 46 feet would be $1,035.00. Under this methodology each customer contributes an amount highly correlated to the actual cost of that service installation.

Q. What level of capital investment has UNS Gas made since the Citizen's acquisition and what does this investment represent in terms of facilities that serve your customers?

A. Since the acquisition of the Citizens properties, UNS Gas has invested approximately $107 million in assets associated with providing safe, reliable service to its customers. Approximately 16% of this investment was for general plant, and 8% was for plant related to public improvement activity. Historically, the Company has collected around $1.3 million annually from new customers in the form of contributions. UNS Gas' proposed changes in the line extension guidelines are expected to increase that amount to approximately $3.5 million annually, assuming the average addition of 3,500 customers each year. This equates to approximately 86% of the cost for new service installation being collected in the form of a contribution.

Q. How does the Incremental Cost Study accomplish the goal of growth paying for growth if the new customer does not pay for the entire length of the new main distribution line?

A. The Company believes its proposed rates, in conjunction with the ICS, will recover a more socially optimal amount from new customers. UNS Gas periodically analyzes customer usage patterns and anticipated usage by revenue area to derive the contribution estimates for average customers in the specific trend areas. State and Federal taxes, property taxes, composite assessments, and depreciation rates are also included, based on the most recent approved factors for these items from UNS Gas' last general rate case. The resulting rate of return ("ROR") on "incremental" rate base is compared to the most recent Commission-authorized ROR to determine the economic feasibility of the extension. UNS Gas generally takes a refundable advance equal to the initial investment in the gas facilities dedicated exclusively to serve the new customers. If the new line extension does not ultimately add the needed level of customers (sales) to provide a return at least equal to the

Commission-authorized ROR, a CIAC is then deducted from the advance in the amount necessary to assure that existing customers are essentially held harmless based on the initial assumptions used in the study.

Q. Please summarize UNS Gas' position on proposing a hook-up fee.

A. UNS Gas believes that it has adopted a fair and reasonable balance with the use of a Line Extension tariff with updated costs (thus requiring new customers to pay the specific costs to serve their premise) and by using, and continually reviewing and monitoring, the ICS process to insure that developments produce a return equivalent to the ROR built into current rates or contribute towards the investment until that return is met.

Q. How has the Company complied with the Commission's directive to investigate the issue of developer contributions and to present alternatives?

A. The Company has provided multiple cost recovery mechanisms that insure the potential for new customers and growth of the system to adversely impact existing customers is mitigated and/or even eliminated.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT

GAS-1A

CLEAN VERSION

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SECTION NO. 1
APPLICABILITY OF RULES AND REGULATIONS AND DESCRIPTION OF SERVICE

A. Company is a gas utility operating within portions of the state of Arizona. The Company will provide service to any person, institution or business located within its service area in accordance with the provisions of its Pricing Plans and the terms and conditions of these Rules and Regulations.

B. All gas delivered to any Customer is for the sole use of such Customer on that Customer's premises only. Gas delivered by the Company shall not be redelivered or resold, or the use thereof by others permitted unless otherwise expressly agreed to in writing by the Company. However, those Customers purchasing gas for redistribution to the Customer's own tenants (only on the Customer's premises) may separately meter each tenant distribution point for the purpose of prorating the Customer's actual purchase price of gas delivered among the various tenants on a per unit basis.

C. These Rules and Regulations shall apply to all gas service furnished by the Company to its Customers.

D. These Rules and Regulations are part of the Company's Pricing Plans on file with and duly approved by, the Arizona Corporation Commission. These Rules and Regulations shall remain in effect until modified, amended, or deleted by order of the ACC. No employee, agent or representative of the Company is authorized to modify the Company rules.

E. These Rules and Regulations shall be applied uniformly to all similarly situated Customers.

F. In case of any conflict between these Rules and Regulations and the ACC's rules, these Rules and Regulations shall apply.

G. Whenever the Company and an Applicant or a Customer are unable to agree on the terms and conditions under which such Applicant or Customer is to be served, or are unable to agree on the proper interpretation of the these Rules and Regulations, either party may request assistance from the Consumer Services Section of the Utilities Division of the ACC. The Applicant or Customer also has the option to file an application with the ACC for a proper order, after notice and hearing.

H. The Company's supplying gas service to the Customer and the acceptance thereof by the Customer shall be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for gas service under the Company's Rules and Regulations and applicable Pricing Plans.

SECTION NO. 2
DEFINITIONS

A. In these Rules and Regulations, the following definitions shall apply unless the context requires otherwise:

1. "Advance in Aid of Construction" or "Advance" – Funds provided to the Company by an Applicant under the terms of a main extension agreement, the value of which may be refundable.

2. "Applicant" – A person requesting the Company to supply gas service.

3. "Application" – A request to the Company for gas service, as distinguished from any inquiry as to the availability or charges for such service.

4. "Arizona Corporation Commission" ("ACC") – The regulatory body established by Article XV of the Arizona Constitution.

5. "Billing Month" – The time interval between any two (2) regular readings of the Company's meters at approximately thirty (30) day intervals.

6. "Billing Period" – The time period between two (2) consecutive meter readings that are taken for billing purposes.

7. "British Thermal Unit" ("BTU") – The amount of heat required to raise the temperature of one (1) pound of water one (1) degree Fahrenheit, at Standard Conditions.

8. "CCF" – One hundred (100) cubic feet.

9. "CFH" – Cubic feet per hour.

10. "Commodity Charge" – The unit cost for billed usage as set forth in the Company's Pricing Plans.

11. "Company" – UNS Gas, Inc.

12. "Contributions in Aid of Construction" or "Contribution" – Funds provided to the Company by the Applicant under the terms of a main extension agreement and/or service connection tariff, the value of which are not refundable.

SECTION NO. 2
DEFINITIONS
(continued)

13. "Cubic Foot" –

    a. In cases where gas is supplied and metered to Customers at Standard Delivery Pressure, a cubic foot of gas is the volume of gas, which at the temperature and pressure existing in the meter occupies one (1) cubic foot.

    b. Regardless of the pressure supplied to the Customer, the volume of gas metered will be converted to the volume which the gas would occupy at Standard Conditions.

    c. The standard cubic foot of gas used for testing the gas for heating value shall be that volume of gas which, when saturated with water vapor and at a temperature of sixty (60) degrees Fahrenheit and under a pressure equivalent to that of thirty (30) inches of mercury (mercury at thirty-two (32) degrees Fahrenheit and under standard gravity), occupies one (1) cubic foot.

14. "Curtailment Priority" – The order in which gas service is to be curtailed to various classifications of Customers, as set forth in the Company's Pricing Plans.

15. "Customer" – The person in whose name service is rendered, as evidenced by the signature on the application or contract for that service, or by the receipt and/or payment of bills regularly issued in the person's name regardless of the identity of the actual user of the service.

16. "Customer Charge" – The amount the Customer must pay the Company for the availability of gas service, excluding any gas used, as specified, in the Company's Pricing Plans.

17. "Customer Service Complaint" - Written complaint received from a Customer, or through the ACC on behalf of a Customer.

18. "Day" – Calendar day.

19. "Decatherm" – Ten (10) therms or one million (1,000,000) BTUs.

20. "Distribution Main" – A gas line of the Company from which service lines may be extended to Customers.

21. "Elderly" – A person who is sixty-two (62) years of age or older.

22. "Excess Flow Valve" ("EFV") – A device that is designed to restrict the flow of gas in a single family residence natural gas service line by automatically closing in the event that it is broken downstream of the EFV, completely cut, torn apart or otherwise separated, usually caused by some type of excavation or digging activity.

SECTION NO. 2
DEFINITIONS
(continued)

23. "Handicapped" – A person with a physical or mental condition which substantially contributes to the person's inability to manage his or her own resources, carry out activities of daily living, or protect themselves from neglect or hazardous situations without assistance from others.

24. "Illness" – A medical ailment or sickness for which a residential Customer obtains a verifiable document from a licensed medical physician stating the nature of the illness and that discontinuance of service would be especially dangerous to the Customer's health.

25. "Inability to Pay" – Circumstances where a residential Customer:

    a. Is not gainfully employed and is unable to pay; or

    b. Qualifies for government welfare assistance, but has not begun to receive assistance on the date that the bill is received and can obtain verification from the government welfare agency; or

    c. Has an annual income below the published federal poverty level and can produce evidence of this; and

    d. Signs a declaration verifying that the Customer meets one of the above criteria and is either elderly, handicapped, or suffers from an illness.

26. "Incremental Contribution Study" ("ICS") – The study described in Section 7.B.4 of these Rules and Regulations.

27. "Interruptible Gas Service" – Gas service that is subject to interruption or curtailment as specified in the Company's Pricing Plans.

28. "Law" – Any rule or requirement established and enforced by government authorities.

29. "Main Extension" – The lines and equipment necessary to extend the existing gas distribution system to provide service to additional Customers.

30. "Master Meter" – An instrument for measuring or recording the flow of gas at a single location from which said gas is transported through a piping system to tenants or occupants for their individual consumption.

31. "MCF" – One thousand (1,000) cubic feet.

32. "Meter" – The instrument for measuring and indicating or recording the volume of gas that has passed through it.

33. "Meter Set Assembly" ("MSA") – All gas components downstream of the Customer's inlet service valve to the Customer's point of delivery.

SECTION NO. 2
DEFINITIONS
(continued)

34. "Minimum Charge" – The amount the Customer must pay for the availability of gas service and may include an amount of usage, as specified in the Company's Pricing Plans.

35. "Permanent Customer" – A Customer who is a tenant or owner of a service location who applies for and receives gas service.

36. "Permanent Service" – Service which, in the opinion of the Company, is of a permanent and established character. The use of gas may be continuous, intermittent, or seasonal in nature.

37. "Person" – Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.

38. "Point of Delivery" – The point of delivery for all gas delivered to any Customer shall be at the point of interconnection between the facilities of the Company and those of such Customer.

39. "Premises" – All of the real property and apparatus employed in a single enterprise or residence on an integral parcel of land undivided by public streets, alleys or railways.

40. "Pricing Plan" – A part of the Company's Tariffs which sets forth the rates and charges related to specific categories of Customers, and related terms and conditions.

41. "Residential Subdivision" – Any tract of land which has been divided into four or more contiguous lots for use in the construction of residential buildings or permanent mobile homes for either single or multiple occupancy.

42. "Residential Use" – Service to Customers using gas for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, and other residential uses and includes use in apartment buildings, mobile home parks, and other multi-unit residential buildings.

43. "Restricted Apparatus" – An apparatus prohibited by the ACC, another governmental agency, or the Company.

44. "Rules and Regulations" or "Company Rules" – These Rules and Regulations, which are part of the Company's Tariffs and Pricing Plans.

SECTION NO. 2
DEFINITIONS
(continued)

45. "Service Areas" – The territory in which the Company has been granted a certificate of convenience and necessity and is authorized by the ACC to provide gas service.

46. "Service Establishment Charge" – A charge as specified in the Company's Pricing Plans which covers the cost of establishing a new account.

47. "Service Line" – A gas pipe that transports gas from a common source or supply (normally a distribution main) to the Customer's point of delivery.

48. "Service Reconnection Charge" – A charge specified in the Company's Pricing Plans that must be paid by the Customer prior to re-establishment of gas service each time the gas is disconnected for nonpayment, or for failure to comply with the Company's Pricing Plans. In addition to the Service Reconnection Charge, such returning Customer shall pay the sum of the applicable monthly Customer Charges which would have accrued had the Customer not been disconnected for non-payment or for failure to comply with the Company's Pricing Plans within the preceding twelve (12) month period.

49. "Service Re-establishment Charge" – A charge specified in the Company's Pricing Plans for the re-establishment of service at the same location where the same Customer had ordered a service disconnect within the preceding twelve (12) month period. In addition to the Service Re-establishment Charge, such returning Customer shall pay the sum of the applicable monthly Customer Charges which would have accrued had the Customer not ordered the disconnect.

50. "Service Transfer" – Transfer of service from one Customer to another, when the meter is not turned off.

51. "Single Family Dwelling" – A house, an apartment, or a mobile home permanently affixed to a lot, or any other permanent residential unit which is used as permanent home.

52. "Special Call-Out" – When Company personal is on-call and is called in from home at the request of the Customer in order to provide service.

53. "Standard Conditions" – 14.73 pounds per square inch absolute at sixty (60) degrees Fahrenheit.

54. "Standard Delivery Pressure" – 0.25 pounds per square inch gauge at the meter or point of delivery.

55. "Tampering" – A situation where a meter has been illegally altered. Common examples are meter bypassing and other unauthorized connections. Tampering also includes any action defined as "tampering" under A.R.S. § 40-491(4).

SECTION NO. 2
DEFINITIONS
(continued)

56. "Tariffs" – The documents filed with the ACC that list the services offered by the Company and set forth the terms and conditions and a schedule of the rates and charges for those services and products. These Rules and Regulations are part of the Company's Tariffs. The Company's Pricing Plans are also part of the Company's Tariffs.

57. "Temporary Service" – Service to premises or enterprises that are temporary in character, or where it is known in advance that the service will be of limited duration. Service that, in the opinion of the Company, is for operations of speculative character is also considered temporary service.

58. "Therm" – A unit of heating value, equivalent to one hundred thousand (100,000) BTUs.

59. "Third Party Notice" – A notice sent to a person willing to receive notification of the pending discontinuance of service to a Customer of record, in order to make arrangements on behalf of said Customer that are satisfactory to the Company.

60. "Transmission Line" - A gas line for delivering natural gas that operates at a hoop stress of twenty percent (20%) or more of Specified Minimum Yield Strength ("SMYS"), as defined in CFR 49, Part 192 or that transports gas to a single large volume Customer such as a distribution center, factory, power plant or institutional user.

61. "Trip Charge" – Charges set forth in the Company's Statement of Additional Charges for services such as a Service Transfer, Collection Fee, Customer-Requested Meter Re-read, or Multiple Attempts to Connect.

62. "Unauthorized" – Use of gas services that is not in accordance with ACC rules, the Company's Rules and Regulations, or the Company's Pricing Plans.

63. "Weather Especially Dangerous to Health" – That period of time, commencing with the scheduled termination date, when the local weather forecast as predicted by the National Oceanic and Atmospheric Administration, indicates that the temperature will not exceed thirty-two (32) degrees Fahrenheit for the next day's forecast. The ACC may determine that other weather conditions are especially dangerous to health as the need arises.

64. "Yardline" – A gas pipe that transports gas from the Customer's point of delivery to the point of entry into the Customer's residence or other place of consumption.

SECTION NO. 3
ESTABLISHMENT OF SERVICE

A. Information From Applicants

1. The Company may obtain the following minimum information from each Applicant:

   a. Name or names of Applicant(s);
   b. Service address or location and telephone number;
   c. Billing address or location and telephone number, if different than service address;
   d. Address where service was provided previously;
   e. Date Applicant will be ready for service;
   f. Indication of whether premises have been supplied with gas service previously;
   g. Purpose for which service is to be used;
   h. Indication of whether Applicant is owner or tenant of or agent for, the premises;
   i. Information concerning the gas usage and demand requirements of the Customer; and
   j. Type and kind of life-support equipment, if any, used by the Customer.

2. The Company may require a new Applicant for service to appear at the Company's designated place of business to produce proof of identity and sign the Company's application form.

3. Where service is requested by two or more individuals, the Company shall have the right to collect the full amount owed to the Company from any one of the Applicants.

4. An Applicant for gas service to new construction or a new extension shall complete the following Company form:

   a. New Service Application Form

   The Customer is responsible for completing and returning the Application form. Failure on the part of the Customer to provide a completed form shall be grounds for the Company to delay or refuse service. For the purpose of this Rule, the definition of new construction/extension is where there is a need to run a new service line or install new gas facilities to a property that has never had prior natural gas service.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

B. Deposits

1. The Company may require from any present or prospective Customer a security deposit to guarantee payment of all bills. This deposit may be retained by the Company until service is discontinued and all bills have been paid; except as provided in Subsection B.4 below. Upon proper application by the Customer, the Company shall then return said deposit, together with any unpaid interest accrued thereon from the date of commencement of service or the date of making the deposit, whichever is later. The Company shall be entitled to apply said deposit together with any unpaid interest accrued thereon, to any indebtedness for the same class of service owed to the Company for gas service furnished to the Customer making the deposit. When said deposit has been applied to any such indebtedness, the Customer's gas service may be discontinued until all such indebtedness of the Customer is paid and a like deposit is again made with the Company by the Customer. No interest shall accrue on any deposit after discontinuance of the service to which the deposit relates.

   The Company shall not require a deposit from a new Applicant for residential service if the Applicant is able to meet any of the following requirements:

   a. The Applicant has had service of a comparable nature with the Company at another service location within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months, or was not disconnected for nonpayment; or

   b. The Applicant can produce a letter regarding credit or verification from a gas or electric utility which states that the Applicant has had service of a comparable nature with that utility at another service location within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months, or was not disconnected for nonpayment; or

   c. In lieu of a cash deposit, a new Applicant may provide a Letter of Guarantee from an existing Customer of the Company who is acceptable to the Company, a surety bond, or similar alternative acceptable to the Company, such as a Certificate of Deposit, as security for Company in the sum equal to the required deposit; or

   d. If a credit check is offered by the Company, the Applicant authorizes a credit check and meets the standards established by the Company.

2. The Company may issue a non-assignable, non-negotiable receipt to the Applicant for the deposit. The inability of the Customer to produce such a receipt shall in no way impair the Customer's right to receive a refund of the deposit which is reflected on the Company's records.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

3. Cash deposits held by the Company twelve (12) months or longer shall earn interest at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published in the Federal Reserve website. No interest will be paid on deposits for which Customers have turned service on and off within the same calendar month. Such payment of interest shall be made during January of each year for Customers served by the Company for at least six (6) months and will cover all interest accrued up to the end of the preceding calendar year or on the date the deposit is returned to the Customer, pursuant to Subsection B.4 below. At the Company's option, the above payments may be made either by check or by credit on the monthly bill.

4. All deposits of residential or commercial Customers received and held by the Company shall be returned to the Customer by the Company (with interest, as provided by Subsection B.3 above), at such time as the affected Customers shall have maintained for a period of twelve (12) consecutive months (from and after the date when the deposit was made), their accounts with the Company. The Customer's accounts shall have been maintained in such a manner that they shall not have been delinquent in the payment of more than two (2) bills during such twelve (12) month period, whether at the same address or at a different address, nor have had their gas service, whether at the same address or at a different address, discontinued, in accordance with these Rules and Regulations, for failure to pay for gas service previously rendered.

5. The Company may require a Customer to establish or re-establish a deposit if the Customer became delinquent in the payment of three (3) or more bills within a twelve (12) consecutive month period, or has been disconnected from service during the last twelve (12) months.

6. The Company may review the Customer's usage after service has been connected and adjust the deposit amount based upon the Customer's actual usage. A separate deposit may be required for each meter installed.

7. Residential Customer deposits shall not exceed two (2) times that Customer's estimated average monthly bill. Non-residential Customer deposits shall not exceed two and one-half (2.5) times that Customer's maximum estimated monthly bill. If actual usage history is available, then that usage, adjusted for normal weather, will be the basis for the estimate.

8. The posting of a deposit shall not preclude the Company from terminating service when the termination is due to the Customer's failure to perform any obligation under the agreement for service or any of these Rules and Regulations.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

C. Grounds For Refusal Of Service

The Company may refuse to establish service if any of the following conditions exist:

1. The Applicant has an outstanding amount due for the same class of gas service with the Company and the Applicant is unwilling to make arrangements with the Company for payment; or

2. A condition exists which, in the Company's judgment, is unsafe or hazardous to the Applicant, the general population, or the Company's personnel or facilities; or

3. The Applicant refuses to provide the Company with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements; or

4. Customer is known to be in violation of the Company's Pricing Plans; or

5. Customer fails to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the Customer and which have been specified by the Company as a condition for providing service; or

6. Applicant falsifies his or her identity for the purpose of obtaining service.

D. Service Establishment, Re-establishment or Reconnection Charge

1. For the purpose of this Rule, the definition of service establishment is where the Customer's facilities are ready and acceptable to the Company, the Applicant has obtained all required permits and/or inspections indicating that the Applicant's facilities comply with local construction safety and governmental standards and regulations, and the Company needs only to install a meter, read a meter, or turn the service on.

2. The Company will charge for service establishment, re-establishment, or reconnection other than service transfers under usual operating procedures, during regular business hours as set forth in the Statement of Additional Charges.

3. Should service be established re-established, or reconnected during a period after the Company's regular business hours, at the Customer's request, the Customer will be required to pay an after-hour charge for the service connection as set forth in the Statement of Additional Charges. Where the Company's scheduling will not permit service establishment on the same day as requested, the Customer can elect to pay the after-hour charge for establishment that day, or his service will be established on the next available business day. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having staff available; there is no guarantee that the Company will have the staffing available for service establishment, re-establishment or reconnection after business hours.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

4. For service re-establishments at the same location where the same Customer has ordered a service disconnect within the preceding twelve (12) month period, such returning Customer, in addition to the service re-establishment charge, shall pay the sum of the applicable monthly Customer Charges that would have accrued had the Customer not ordered the disconnect.

5. For service reconnections when due to the behavior of the Customer (*i.e.*, nonpayment, failure to comply with the Company's Pricing Plans) it has been necessary for the Company to discontinue service utilizing other than usual operating procedures prior to reconnection of gas service each time the gas is disconnected, in addition to the service reconnection charge set forth in the Statement of Additional Charges, the Customer shall pay the sum of the applicable monthly Customer Charges that would have accrued had the Customer not been disconnected within the preceding twelve (12) month period.

6. The Company will charge for the establishment or re-establishment for service transfers only, as set forth in the Statement of Additional Charges.

7. When the Company has made more than one failed attempt to establish service due to the Customer's absence from home, facilities not being ready, or lack of access to the point of delivery, the Customer will be required to pay a multiple attempts to connect charge as set forth in the Statement of Additional Charges, in addition to the service establishment charge.

E. Temporary Service

1. Applicants for temporary service may be required to pay to the Company, in advance of service establishment, the estimated cost of installing and removing the facilities necessary for furnishing the desired service.

2. Where the duration of service is to be less than one (1) month, the Applicant may also be required to advance a sum of money equal to the estimated bill for service.

3. Where the duration of service is to exceed one (1) month, the Applicant may also be required to meet the deposit requirements of the Company, as outlined in Subsection B.1 above.

4. If at any time during the term of the agreement for service the character of a temporary Customer's operations changes so that, in the opinion of the Company, the Customer is classified as permanent, the terms of the Company's main extension rules shall apply.

SECTION NO. 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS

A. Information for Residential Customers

1. The Company shall make available upon Customer request, no later than sixty (60) days from the date of request, a concise summary of the rate schedule applied for by such Customer. The summary shall include the following:

    a. Monthly minimum or Customer charge, identifying the amount of the charge and the specific amount of usage included in the minimum charge, where applicable;

    b. Rate blocks, where applicable; and

    c. Any adjustment factor(s) and method of calculation.

2. Upon application or upon request, the Applicant or the Customer shall elect the applicable Pricing Plan best suited to their requirements. The Company may assist in making such election, but shall not be held responsible for notifying the Customer of the most favorable Pricing Plan and shall not be required to refund the difference in charges under different Pricing Plans.

    However, new non-residential Customers whose projected consumption is near the threshold between "large" and "small" Pricing Plans, may elect the "small" rate, subject to refund, if their usage qualifies them as a "large" Customer. An existing non-residential Customer will be moved to the "large" rate, or once moved, back to the "small" rate, only if their consumption history or a clear permanent change in consumption makes it clear the Customer will meet the volume requirements of one Pricing Plan.

    A review may be initiated by either the Company or the Customer. Any change of Pricing Plan, if appropriate, will be effective with the first bill issued seven (7) days after the initiation of the review. No adjustment of past billings due to Pricing Plan selection will be made to either the Company or the Customer, except for a new Customer who qualifies for the "large" Pricing Plan based on twelve (12) months of usage as set forth in this Rule.

3. Upon Customer request, the Company shall make available to the Customer, a copy of the ACC's Rules and Regulations (Arizona Administrative Code, Title 14, Article 3 - Gas Utilities) concerning:

    a. Deposits;

    b. Termination of Service;

    c. Billing and Collection; and

    d. Complaint Handling.

4. The Company, upon Customer request, shall transmit a written statement of actual consumption by the Customer for each billing period during the prior twelve (12) months unless such data is not reasonably ascertainable.

SECTION NO. 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS
(continued)

5. The Company shall inform all new Customers of their rights to obtain the information specified above.

6. The Company shall notify each Customer of the following information, in writing, within ninety (90) days after the Customer first receives gas service at a particular location:

   a. The Company does not maintain the Customer's buried piping;

   b. If the Customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage;

   c. Buried gas piping should be periodically inspected for leaks, periodically inspected for corrosion if the piping is metallic, and repaired if any unsafe condition is discovered;

   d. When excavating near buried gas piping, the piping must be located in advance, and the excavation done by hand;

   e. Plumbing contractors and heating contractors may assist in locating, inspecting, and repairing the Customer's buried piping; and

   f. In order to reduce damage by outside forces, the Company is a member of the statewide one call system in all areas in which the Company has underground natural gas piping.

B. Information Required Due to Changes in Rates and Charges

1. The Company shall send affected Customers a concise summary of any changes in the Company's rates and charges significantly impacting those Customers.

2. This information shall be sent to the affected Customer(s) within sixty (60) days of the effective date of the change in the Company's rates and charges.

SECTION NO. 5
MASTER METERING

A. Mobile Home Parks – New Construction/Expansion

1. The Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion are individually metered by the Company. Main extensions and service line connections to serve such new construction or expansion shall be governed by the main extension and/or service line connection policies of these rules and regulations.

2. Permanent residential mobile home parks for the purpose of this rule shall mean mobile home parks where the average length of stay for an occupant is a minimum of six (6) months.

3. For the purpose of this rule, expansion means construction which has been started for additional permanent residential spaces after the effective date of this rule.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS

A. Priority and Timing of Service Establishments

1. After an Applicant has complied with the Company's application and deposit requirements and has been accepted for service by the Company, the Company shall schedule that Customer for service establishment.

2. Service establishment shall be scheduled for completion within five (5) business days of the date the Customer has been accepted for service, except in those instances when the Customer requests service establishment beyond the five (5) business day limitation.

3. When the Company has made arrangements to meet with a Customer for service establishment purposes and the Company or the Customer cannot make the appointment during the prearranged time, the Company shall reschedule the service establishment appointment to the satisfaction of both parties.

4. The Company shall schedule service establishment appointments within a maximum range of four (4) hours during normal business hours, unless another time frame is mutually acceptable to the Company and the Customer.

5. Service establishments shall be made only by qualified service personnel of the Company or its authorized representatives.

6. For the purpose of this rule, service establishments can occur only when the Customer's facilities are ready and acceptable to the Company and the Company needs only to install, read the meter, or turn the service on.

7. Whenever an Applicant requests after-hours handling of his request, the Company shall charge a fee set forth in the Statement of Additional Charges unless a special call out is required. If a special call out is required, the charge shall be for a minimum of one (1) hour at a rate set forth in the Statement of Additional Charges for the service work on the Customer's premises. Special handling of calls and the related charges shall be made only upon request of the Applicant. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having staff available; there is no guarantee that the Company will have the staffing available for service establishment, re-establishment or reconnection after regular business hours.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

B. Facilities

1. Customer Provided Facilities

a. An Applicant for service shall be responsible for the safety and maintenance of all Customer piping from the point of delivery to the point of consumption.

b. Meters shall be installed in a location suitable to the Company where the meters will be safe from street traffic, readily and safely accessible for reading, testing and inspection, and where such activities will cause the least interference and inconvenience to the Customer. The Customer shall provide, without cost to the Company and at a suitable and easily accessible location, sufficient and proper space for the installation of meters.

c. Where the meter or service line location on the Customer's premises is changed at the request of the Customer or due to alterations on the Customer's premises, the Customer shall provide, and have installed at his expense, all Customer piping necessary for relocating the meter and the Company may make a charge for moving the meter and/or service line.

d. On all newly-constructed Customer piping at the meter interconnection, the Customer will be required to install necessary piping and equipment before the meter is installed.

2. Company Provided Facilities

a. The Company will install, at its own expense, the meter set assembly ("MSA") at a suitable location near the side wall of the Customer's building approximately three (3) feet or more from that front corner of the building nearest to the street in which the Company's distribution main is located. However, the Company, at its option, has the right to locate the meter at any location meeting the criteria of Subsection B.1.b of this section.

The three (3) feet as noted above refers to the approximate location of the meter from the corner of the building that is nearest to the street in which the distribution main servicing that Customer is located. The gas service riser, service cock, regulator and meter are all above ground. The service from the Company's distribution main to the building is below ground.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

b. The Company or authorized representative will install the gas service line and make all connections of the gas service line from the distribution main to the service riser. The Company will in all cases be responsible for the cost of construction of the service line from the Company's distribution main to the Customer's property line for an amount not to exceed the allowable investment as calculated by the Incremental Contribution Study (see Section No. 7, Subsection B), with the Customer reimbursing the Company for the difference. The Customer will reimburse the Company for the gas service line on the Customer's property at a rate of twenty-two dollars and fifty cents ($22.50) per foot. The Customer is responsible for removal of landscaping prior to installation or be subject to applicable charges. For Customers who provide the trench for the service line on the Customer's property, Section No. 7, Subsection B.4.d will apply and the Customer will reimburse the Company at a rate of sixteen dollars and fifty cents ($16.50) per foot. The Customer, at the Customer's own expense, shall furnish, install, and be responsible for all other pipe, fittings, connections, and appurtenances between the point of delivery and each point of consumption. The cost of installation, paid by the Applicant, shall be the average actual cost of installation, calculated and averaged annually by the Company.

c. No Customer-owned pipe shall be directly connected with the Company's distribution mains or services. No connection shall be made by the Customer between the facilities of the Company, including the meter, service cock and regulator and those of the Customer, nor shall any facilities of the Company be set, connected, disconnected, removed, repaired or altered except by the Company's representatives.

d. A single meter and a single point of delivery may be used to supply a group of buildings, such as those of a hospital or industrial establishment under single ownership or control. Such applications may fall under the Master Meter rule as defined in the Arizona Administrative Code.

e. The Company may decline service to mobile residences or portable or other temporary structures if the conditions do not afford adequate protection for the occupant(s) thereof, or the persons or property of others. In no event will gas service be permitted, if to the Company's knowledge, the Customer or the Customer's facilities fail to meet applicable requirements of law, of the State, or of any local code.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

3. Easements and Right-of-Way

Each Customer shall grant, at no cost to the Company, an adequate easement and right-of-way, satisfactory to the Company to ensure proper service connection. Failure on the part of the Customer to grant an adequate easement and right-of-way shall be grounds for the Company to refuse service.

4. Unauthorized work or facilities

When the Company discovers that a Customer or the Customer's Agent has performed work or has constructed facilities that has altered the installation of the Company's facilities to the point that work is necessary to restore the previously installed Company facilities to meet regulatory or Company requirements, the Company shall notify the Customer or the Customer's Agent and the Company shall take whatever actions are necessary to eliminate the hazard or violation at the Customer's expense.

5. Point of Delivery

The point of delivery for all gas delivered to any Customer shall be at the point of interconnection between the facilities of the Company and those of the Customer.

6. Excess Flow Valve Installation

In accordance with Title 49, Section 192.381 of the Code of Federal Regulations and requirements set forth in HR5782, the installation of an Excess Flow Valve ("EFV") shall be performed by the Company on each single family residence service line connected to its distribution system whether the service line is installed or entirely replaced.

a. The Applicant shall provide the Company information concerning the gas usage and demand requirements. The EFV will be designed and constructed so that suitable gas capacity is available and satisfactory to the Company.

b. The Company will construct, own, operate, and maintain the EFV in connection with the service line installation.

c. Costs associated with the mandated installation of the EFV shall be paid by the Applicant as a nonrefundable Contribution in Aid of Construction ("CIAC").

i. The cost of installation, paid by the Applicant, shall be the average actual cost of installation, calculated and averaged annually by the Company.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

d. Where it is necessary to change or alter the EFV, due to a request or alteration of the Customer's premise by the Customer, the Customer shall reimburse the Company for all expenses in connection with upgrading or removing the EFV.

e. The Company shall pay for all costs associated with replacement or maintenance of the EFV in connection with a line replacement or maintenance project.

SECTION NO. 7
EXTENSION OF LINES

Extensions of gas distribution services and mains necessary to furnish permanent service to Applicants will be made in accordance with this rule.

A. General

The Company will construct, own, operate and maintain service line and distribution main extensions.

1. Gas service lines will be designed and installed so that suitable capacity from the Company's distribution main to a meter location on the property of the Applicant is satisfactory to the Company. If downstream usage changes or is altered by the Customer, the Customer may be responsible for costs to upgrade or enlarge the service line to accommodate additional capacity requirements.

2. Gas distribution main extensions will be only along public streets, roads, and highways, which the Company has legal right to occupy, and on public lands and private property across which rights-of-way, satisfactory to the Company, may be obtained.

3. All Company distribution mains and service lines shall be installed in accordance with all applicable Company standards.

B. Service and Main Extensions to Applicants for Service

General Policy – All service line and main line extension agreements are made on the basis of economic feasibility.

1. Facility Charge – If any Applicant fails to use natural gas for equipment stated in the application and used as the basis for estimating the allowable investment within four (4) months of the completion of the main, the Company may bill the Applicant for the incremental cost allowed towards the extension of service. The Applicant shall pay within forty-five (45) days the charge as a non-refundable contribution towards the cost of extending service.

2. At its option, the Company may require a performance bond or other surety guaranteeing bona fide operation of the facility for which the extension is requested, in accordance with Applicant's representation in the contract.

SECTION NO. 7
EXTENSION OF LINES
(continued)

3. Master Meter Extensions – If the residential Customers are tenants in a fully improved master-metered mobile home park ("MMP") and the MMP is currently or was formerly served as a master-metered mobile home park, the allowable investment for the MMP will be calculated by the following Incremental Contribution Method and formula:

$$AI = (FR - CR) \times 5$$

where: AI = Allowable Investment

FR = The MMP's estimated future total annual revenue, assuming conversion to individual residential service, using the MMP's average park occupancy for the past two (2) years, less the Company's current average cost of purchased gas.

CR = The MMP's current total annual revenue, under the applicable schedule, averaged for the past two (2) years, less the Company's current average cost of purchased gas. If the MMP is not a current Customer of the Company, the CR will be determined on the basis of engineering estimates of occupancy and usage.

The Company will install that portion of each service in excess of the allowed investment subject to a nonrefundable contribution to be paid by the Applicant MMP prior to construction. In no event shall costs above the allowable investment be borne by the Company.

4. Incremental Contribution Method – Gas service line and main line extensions will be made by the Company at its expense for an amount not to exceed the allowable investment as calculated by an Incremental Contribution Study ("ICS").

   a. Allowable investment shall mean a determination by the Company that the revenues less the incremental gas cost to serve the Applicant provides a rate of return on the Company's investment no greater than the weighed average cost of capital authorized by the ACC in the Company's most recent general rate case.

   b. If the ICS has an allowable investment that is more than the cost of the main extension, then the excess amount may be applied to reduce the cost of service line installation up to the Customer's property line, except that it shall not be used to reduce the cost of excess flow valve installation which shall be paid by the customer.

   c. The Company, after conducting an ICS, may at its option, extend its facilities to Customers whose usage does not satisfy the definition of economic feasibility, but who otherwise are permanent Customers, provided the Customer pays a nonrefundable contribution, necessary to make the extension economically feasible.

   d. Applicants may provide trenching for service lines and/or distribution mains to the Company's specifications and the Applicant's costs will be reduced accordingly.

SECTION NO. 7
EXTENSION OF LINES
(continued)

e. Customers provided with line extensions using the ICS shall be reviewed annually for a period of five (5) years to determine the amount of any refund, as described in Subsection B.5 below.

f. For the purposes of this rule, "economic feasibility" means that the estimated incremental revenues derived from serving the Applicant, less the incremental gas cost to serve the Applicant, meets the estimated costs of serving the Applicant, including meeting capital costs as determined by the weighed average cost of capital authorized by the ACC in the Company's most recent general rate case. An extension will not be considered economically feasible if the Applicant does not install a functioning water heater and furnace within four (4) months of the completion of the main.

5. Method of Refund

Amounts advanced by the Customer(s) in accordance with this rule, less any unpaid Facility Charges, shall be refunded, without interest, in the following manner:

a. Refunds of an advance shall be made for each additional separately metered permanent service connected to the main extension for which an advance was collected using an ICS that includes the additional Customer(s).

b. No refunds will be made for additional Customers connecting to a further extension or series of extensions constructed beyond the original extension.

c. The Customer may request an annual survey to determine if additional Customers have been connected to and are using service from the extension. In no case shall the amount of the refund exceed the amount originally advanced.

d. The refund period shall be five (5) years from the date of the completion of the extension. No refunds will be made by the Company after the termination of the refund period. Any portion of the advance that remains unrefunded at the end of the refund period shall be considered an unrefundable contribution.

e. Any assignment by a Customer of their interest in any part of an advance, which at the time remains unrefunded, must be made in writing and approved by the Company.

f. Amounts advanced under a gas main extension rule previously in effect will be refunded in accordance with the provisions of that rule.

SECTION NO. 7
EXTENSION OF LINES
(continued)

C. Service and Main Extensions to Service Individually Metered Subdivisions, Tracts, Housing Projects, Multi-Family Dwellings and Mobile Home Parks or Estates

1. Advances

a. Gas distribution service and main extensions to and within individually metered subdivisions, tracts, housing projects, multi-family dwellings and mobile home parks or estates will be constructed, owned and maintained by the Company in advance of applications for service by bona fide Customers only when the entire estimated cost of such extensions as determined by the Company, is advanced to the Company, and a main extension agreement is executed. This advance may include the cost of any gas facilities installed at the Company's expense in conjunction with a previous service or main extension in anticipation of the current extension.

b. The Company may require a subdivider, builder or developer to provide trenching for service lines and/or distribution mains and may also require the subdivider, builder or developer to provide bedding & shading material to Company specifications.

c. For developers who have entered into a main extension agreement and facilities have been installed and then they or some other party request subsequent reconfiguring of facilities or other changes requiring additional expenditures by the Company, these new costs will be entirely paid for with a non-refundable contribution and any refunds will be made in accordance with the original agreement. No additional agreement or extension of the time for refunds will be made to cover the area piped under the original extension agreement.

d. Upon completion of installation, the Company will perform a reconciliation of the estimate to actual costs incurred and may bill the Customer for any variance with the new amount included in the refundable balance, or at the Company's option withhold refunds until the underpayment is satisfied.

e. See Subsection B.3 above for requests to serve MMP through individual residential meters if the MMP is currently or was formerly served under an MMP schedule.

f. Refunds will be made to developers as described in Subsection B.5 above.

D. General Conditions

1. Postponement of Advance

The Company, at its option, may postpone, for a period not to exceed five (5) years that portion of an advance which it estimates would be refunded under the provisions of this rule. At the end of such refund period, the Company shall collect all such amounts not previously advanced. When advances are postponed, the Applicant may be required to furnish to the Company, a Company-approved surety, to assure payment of any postponed amounts throughout the term of the facilities extension agreement up until the end of the postponement period.

SECTION NO. 7
EXTENSION OF LINES
(continued)

2. The Applicants or developer will provide property location, tax identification numbers, lot numbers, street names and other property information helpful to planning an extension.

3. Contracts

   a. Each Applicant requesting an extension in advance of applications for service will be required to execute a main extension agreement covering the terms under which the Company will install distribution mains in accordance with the provisions of the Company's Pricing Plans.

   b. At the time service is requested, the Applicant will submit a list of natural gas equipment to be used including the BTU input.

4. One Service for a Single Premise

   a. The Company will not install more than one service line to supply a single premise, unless it is for the convenience of the Company or an Applicant requests an additional service, and in the opinion of the Company, an unreasonable burden would be placed on the Applicant if the additional service were denied. When an additional service is installed at the Applicant's request, the Applicant shall make a nonrefundable contribution for the additional service based on the Company's estimated cost.

   b. When a service extension is made to a meter location upon private property which is subsequently subdivided into separate premises, with the ownership portions thereof divested to other than the Applicant or the Customers, the Company shall have the right, upon written notice, to discontinue service without obligation or liability. Gas service, as required by the Applicant or Customer, will be reestablished in accordance with the applicable provisions of the Company's rules.

5. Branch Services

   The Company, at its option, may install a branch service for units on adjoining premises.

SECTION NO. 7
EXTENSION OF LINES
(continued)

6. Main Extension Agreement Requirements

   a. Upon request by an Applicant for a main extension, the Company shall prepare, without charge, a preliminary sketch and rough estimate of the cost of the installation to be advanced by the Applicant.

   b. Any Applicant for a main extension requesting the Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with the Company an amount equal to the estimated cost of preparation. The Company shall, upon request, make available within ninety (90) days after receipt of the deposit referred to above, such plans, specifications, or cost estimates of the proposed main extension. Where the Applicant authorizes the Company to proceed with the construction of the extension, the deposit shall be credited to the cost of construction; otherwise, the deposit shall be nonrefundable. If the extension is to include oversizing of facilities to be done at the Company's expense, appropriate details shall be set forth in the plans, specifications and cost estimates. Subdividers providing the Company with approved subdivision plats shall be provided with plans, specifications or cost estimates within forty-five (45) days after receipt of the deposit referred to above.

   c. The estimated cost of main extension and any resulting Main Extension Agreement is valid for ninety (90) days from the date of Company issue. Any signed agreement with appropriate payment where construction does not commence within ninety (90) days may be subject to review, recalculation and adjustment of advance requirements.

   d. Where the Company requires an Applicant to advance funds for a main extension, the Company will furnish the Applicant, upon request, with a copy of this rule prior to the Applicant's acceptance of the Company's extension agreement.

SECTION NO. 7
EXTENSION OF LINES
(continued)

e. All main extension agreements requiring payment by the Applicant shall be in writing, signed by each party and shall include the following:

i. Name and address of Applicant(s);

ii. Proposed service address(es) or location(s);

iii. Description and sketch of the requested main extension;

iv. Description of requested service differentiated by Customer class;

v. Number of Customers served;

vi. Estimated cost to construct facilities;

vii. The Company's estimated start date and completion date for construction of the main extension;

viii. Each Applicant shall be provided a copy of the approved main extension agreements;

ix. Payment terms; and

x. A concise explanation of any refunding provisions, if applicable.

7. Relocation of Service Lines and Distribution Mains

a. When, in the judgment of the Company, the relocation of a distribution main or service line is necessary and is due either to maintenance of adequate service or the operating convenience of the Company, the Company shall perform such work at its own expense.

b. If relocation of a distribution main or service line is due solely to meet the convenience or the requirements of the Applicant or the Customer, such relocation, including metering and regulating facilities, shall be performed by the Company at the expense of the Applicant or the Customer.

c. Relocation of facilities will be mandatory and at the Customer's expense when actions of the Customer restrict the Company's access to or the safety of the facility.

8. Standby Service or Residential Pool Heating

No allowance will be made for equipment used for standby or emergency purposes only or for equipment used for residential pool heating under Section No. 7, Subsection B.4.

SECTION NO. 7
EXTENSION OF LINES
(continued)

9. Temporary Service

Extensions for temporary service or for operations, which in the opinion of the Company are of a speculative character or are of questionable permanency, will require an advance for the entire cost of the facilities needed, with provision for a refund using an ICS calculated annually, or at the termination of the temporary service.

10. Length and Location

The length of distribution mains or service lines required for an extension will be considered as the distance along the shortest practical and available route, as determined by the Company, from the Company's nearest permanent distribution main.

11. Service Impairment to Other Customers

When, in the judgment of the Company, providing service to an Applicant would impair service to other Customers, the cost of necessary reinforcement to eliminate such impairment may be included in the cost calculation for the extension.

12. Service From Transmission Lines

The Company will not tap a gas transmission main except when, in its sole opinion, conditions justify such a tap. Where such taps are made, the Applicant will pay the Company the cost of the tap, and extensions from the tap will be made in accordance with the provisions of this rule.

13. Other Types of Connections

Where an Applicant or Customer requests a type of service connection other than standard such as curb meters and vaults, etc., the Company will consider each such request and will grant such reasonable allowance as it may determine. The Company shall install only those facilities that it determines are necessary to provide standard natural gas service in accordance with the Company's Pricing Plans. Where the Applicant requests the Company to install special facilities which are in addition to, or in substitution for, or which result in higher costs than the standard facilities which the Company would normally install, the extra cost thereof shall be borne by the Applicant.

SECTION NO. 7
EXTENSION OF LINES
(continued)

14. Exceptional Cases

In unusual circumstances, when the application of this rule appears impractical or unjust to either party, the Company or the Applicant may refer the matter to the ACC for special ruling or for the approval of special conditions which may be mutually agreed upon, prior to commencing construction.

15. Taxes Associated with Nonrefundable Contributions and Advances

Any federal, state or local income taxes resulting from a nonrefundable contribution or advance by the Customer in compliance with this rule will be recorded as a deferred tax and appropriately reflected in the Company's rate base. However, if the estimated cost of facilities for any service line or distribution main extension exceeds $500,000, the Company may require the Applicant to include in the contribution or advance an amount (the "gross up amount") equal to the estimated federal, state or local income tax liability of the Company resulting from the contribution or advance, computed as follows:

$$\text{Gross Up Amount} = \frac{\text{Estimated Construction Cost}}{(1 - \text{Combined Federal-State-Local Income Tax Rate})}$$

After the Company's tax returns are completed, and actual tax liability is known, to the extent that the computed gross up amount exceeds the actual tax liability resulting from the contribution or advance, the Company shall refund to the Applicant an amount equal to such excess. When a gross-up amount is to be obtained in connection with an extension agreement, the contract will state the tax rate used to compute the gross up amount, and will also disclose the gross-up amount separately from the estimated cost of facilities. In subsequent years, as tax depreciation deductions are taken by the Company on its tax returns for the constructed assets with tax bases that have been grossed-up, a refund will be made to the Applicant in an amount equal to the related tax benefit. Such refunds will be in addition to any required refunds of actual construction costs required by the extension agreement. In lieu of scheduling such refunds over the remaining tax life of the constructed assets, a reduced lump sum refund may be made at the time when actual construction costs are refunded in full. This lump sum payment shall reflect the net present value of remaining tax depreciation deductions discounted at the Company's authorized rate of return.

SECTION NO. 8
PROVISION OF SERVICE

A. Company Responsibility

1. The Company shall be responsible for the safe transmission and distribution of gas until it passes the point of delivery to the Customer.

2. The Company shall be responsible for maintaining in safe operating condition all meters, regulators, service pipe or other fixtures installed on the Customer's premises by the Company for the purpose of delivering gas to the Customer.

3. The Company may, at its option, refuse service until the Customer's pipes and appliances have been tested and found to be safe, free from leaks, and in good operating condition. Proof of such testing shall be in the form of a certificate executed by a licensed plumber or local inspector certifying that the Customer's facilities have been tested and are in safe operating condition.

4. The Company shall be required to test the Customer's piping for leaks when the gas is turned on. If such tests indicate leakage in the Customer's piping, the Company shall refuse to provide service until such time as the Customer has had the leakage corrected.

5. The Company shall be responsible for the operation and maintenance of all facilities up to the outlet of the meter installed by the Company or its authorized agent.

B. Customer Responsibility

1. Each Customer shall be responsible for maintaining in safe operating condition all Customer piping fixtures and appliances on the Customer's side of the point of delivery.

2. Each Customer shall be responsible for safeguarding all Company property installed in or on the Customer's premises for the purpose of supplying gas service.

3. Each Customer shall exercise all reasonable care to prevent loss or damage to Company property, excluding ordinary wear and tear. The Customer shall be responsible for loss of or damage to, Company property on the Customer's premises arising from neglect, carelessness, or misuse and shall reimburse the Company for the cost of necessary repairs and replacements that arise from neglect, carelessness, or misuse.

4. Each Customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering, tampering, or by-passing the Company's meters. This remedy is cumulative to any other remedy available to Company under law or ACC rules.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

5. Each Customer shall be responsible for promptly notifying the Company of any gas leakage identified in the Customer's or the Company's equipment.

6. The Customer will be responsible for the loss of gas or damage caused by gas in piping beyond the Company's meter.

7. No rent or other charge whatsoever will be made by the Customer against the Company for placing or maintaining meters, regulators, service lines, fixtures, etc. upon the Customer's premises.

C. Continuity of Service

The Company shall make reasonable efforts to supply a satisfactory and continuous level of service.

D. Liability

1. The Company shall not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from the following:

   a. Any cause against which the Company could not have reasonably foreseen or made provision for;

   b. Intentional service interruptions to make repairs or perform routine maintenance; or

   c. Curtailment.

2. Neither the Company nor the Customer shall be liable to the other for any act, omission or circumstances (including, with respect to the Company, but not limited to, inability to provide service) occasioned by or in consequence of flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements, or accident or explosion, or war, rebellion, civil disturbance, mobs, riot, blockade, terrorist actions, or other acts of the public enemy, or acts of God, or interference of civil and/or military authorities, or strikes, lockouts or other labor difficulties, or vandalism, sabotage or malicious mischief, or usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect, or breakage or accidents to equipment or facilities, or lack, limitation or loss of electrical or gas supply, or any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by the exercise of due diligence such party is unable to prevent or overcome; provided, however, that nothing contained herein shall excuse the Customer from the obligation of paying for gas delivered or services rendered.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

3. A failure to settle or prevent any strike or controversy with employees or with anyone purporting or seeking to represent employees shall not be considered to be a matter within the control of the Company.

4. Company will not be responsible for any third-party claims against Company that arise from Customer's use of Company's gas.

5. Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any act or omission of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

6. The liability of the Company for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment shall not exceed an amount equal to the charges applicable under the Company's Pricing Plan (calculated on a proportionate basis where appropriate) to the period during which such error, mistake, omission, interruption or delay occurs.

7. In no event shall the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue or profits) of any kind whatsoever regardless of the cause or foreseeability thereof.

8. The Company shall not be responsible for any loss or damage occasion or caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any regulators, gas piping, appliances, fixtures or apparatus.

E. Change in Character of Service

1. When a change is made by the Company in the type of service rendered which would adversely affect the efficiency of operation or require the adjustment of the equipment of Customers, all Customers who may be affected shall be notified by the Company at least thirty (30) days in advance of the change or, if such notice is not possible, as early as feasible. Where adjustments or replacements of the Company's standard equipment must be made to permit use under such changed condition, adjustments shall be made by the Company without charge to the Customers.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

F. Service Interruptions

1. The Company shall make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

2. The Company shall make reasonable provisions to meet emergencies resulting from failure of service and shall issue instructions to its employees covering procedures to be followed in the event of emergencies in order to prevent or mitigate interruption or impairment of service.

3. In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

4. When the Company plans to interrupt service for more than four (4) hours to perform necessary repairs or maintenance, the Company shall attempt to inform affected Customers of the scheduled date and estimated duration of the service interruption at least twenty-four (24) hours in advance. Such repairs shall be completed in the shortest possible time to minimize the inconvenience to the Customers.

5. The ACC shall be notified of interruptions in service affecting the entire system or any major division of the entire system. The interruption of service and the cause shall be reported by telephone to the ACC within one (1) hour after the responsible representative of the Company becomes aware of said interruption, and shall be followed by a written report to the ACC.

G. Heat Value Standard for Natural Gas

The Company shall supply gas to its Customers with an average total heating value of not less than nine hundred (900) BTUs per cubic foot. The number of BTUs per cubic foot actually delivered through the Customer's meter will vary according to the altitude and elevation of the location where the Customer is being provided service.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

H. Standard Delivery Pressure

1. The Company shall maintain the Standard Delivery Pressure at the outlet of the Customer's meter, subject to variation under load conditions.

2. In cases where a Customer desires service at greater than Standard Delivery Pressure, the Company may supply, at its option, such greater pressure if and only as long as the furnishing of gas to such Customer at higher than standard delivery pressure will not be detrimental to the service of other Customers of the Company. The Company reserves the right to lower the delivery pressure or discontinue the delivery of gas at higher pressure at any time upon reasonable notice to the Customer. Where service is provided at pressure higher than Standard Delivery Pressure, the meter volumes shall be corrected to that higher pressure.

I. Determination of Therms for Billing

1. Heating Value – The heating value (BTU per cubic foot) of the natural gas delivered will vary depending on the source of supplies received by the Company. The average heating values will be determined from the volumetric weighted average heating values of the supplies received by the Company.

2. Metered Volumes – The number of therms to be billed will be determined by multiplying the difference in meter readings by an appropriate billing factor.

a. Therms are determined from the volumes measured by the following:

$$\frac{\text{A: Atmospheric Pressure at Elevation + Delivery Pressure}}{\text{14.73 Atmospheric Pressure at Sea Level}} \times \frac{\text{B: Average Heating Value (BTU per cubic foot)}}{\text{100,000 BTU per Therm}} \times \text{C: Super Compressibility Factor}$$

Where:

A = Correction for atmospheric pressure at elevation and applicable delivery pressure
B = Applicable heating value of natural gas received
C = Correction for super compressibility ratio

b. Atmospheric Pressures at Elevations within the Company's service territory are outlined in the following table. At such time additional elevation bands are needed within the various areas served by the Company, new bands will be added.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

Elevation Range	Atmospheric Pressure Base
201 - 400	14.57206
401 - 600	14.46665
601 - 800	14.36200
801 - 1000	14.25810
1001 - 1200	14.15495
1201 - 1400	14.05253
1401 - 1600	13.95084
1601 - 1800	13.84987
1801 - 2000	13.74962
2001 - 2200	13.65007
2201 - 2400	13.55122
2401 - 2600	13.45306
2601 - 2800	13.35558
2801 - 3000	13.25878
3001 - 3200	13.16265
3201 - 3400	13.06718
3401 - 3600	12.97237
3601 - 3800	12.87820
3801 - 4000	12.78468
4001 - 4200	12.69179
4201 - 4400	12.59954
4401 - 4600	12.50791
4601 - 4800	12.41689
4801 - 5000	12.32648
5001 - 5200	12.23668
5201 - 5400	12.14748
5401 - 5600	12.05887
5601 - 5800	11.97084
5801 - 6000	11.88340
6001 - 6200	11.79653
6201 - 6400	11.71023
6401 - 6600	11.62449

SECTION NO. 8
PROVISION OF SERVICE
(continued)

Elevation Range	Atmospheric Pressure Base
6601 - 6800	11.53932
6801 - 7000	11.45469
7001 - 7200	11.37061
7201 - 7400	11.28708
7401 - 7600	11.20408

J. Construction Standards and Safety

The Company's pipelines and pipeline facilities for the transportation of gas within the State of Arizona shall conform with and be subject to the Federal Safety Standards as adopted by the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration. The Company maintains and updates an Operation and Maintenance plan and an Emergency plan. Upon discovery of occurrence, the Company will report all incidents as required under the Arizona Administrative Code, R14-5-203.

SECTION NO. 9
METER READING

A. Company or Customer Meter Reading

1. The Company may, at its discretion, allow for Customer reading of meters.

2. It shall be the responsibility of the Company to inform the Customer how to properly read the Customer's meter.

3. Where a Customer reads the meter, the Company will read the Customer's meter at least once every six (6) months.

4. The Company shall specify the timing requirements for the Customer to submit the monthly meter reading to conform to the Company's billing cycle.

5. In the event the Customer fails to submit the meter reading on time, the Company may issue the Customer an estimated bill.

6. Meters shall be read monthly on as close to the same day each month as practical.

B. Measuring of Service

1. All gas sold by the Company shall be metered, except in the case of gas sold according to a fixed charge schedule, or when otherwise authorized by the ACC.

2. When there is more than one (1) meter at a location, the metering equipment shall be so tagged or plainly marked as to indicate the facilities being metered.

3. If and when the Company installs multiple meters or service lines to serve a single Customer for the Company's convenience, meter readings may be combined for billing purposes.

C. Customer-Requested Meter Rereads

1. At the request of a Customer, the Company will reread that Customer's meter within ten (10) business days after such request by the Customer.

2. Any reread will be charged to the Customer at a rate set forth in the Statement of Additional Charges, provided that the original reading was not in error

3. When a reading is found to be in error, the re-read shall be at no charge to the Customer.

SECTION NO. 9
METER READING
(continued)

D. Access to Customer Premises

The Company shall have the right of safe ingress to and egress from the Customer's premises at all reasonable hours for any purpose reasonably connected with the furnishing of service and the exercise of any and all rights secured to the Company by law or the ACC's rules or the Company's Pricing Plans.

E. Customer-Requested Meter Tests

The Company shall test a meter upon Customer request and shall be authorized to charge the Customer for such meter test. The charge for the meter test is set forth in the Statement of Additional Charges. However, if the meter is found to be in error by more than three percent (3%), no fee will be charged to the Customer.

SECTION NO. 10
BILLING AND COLLECTION

A. Frequency and Estimated Bills

1. The Company shall bill monthly for services rendered. Meter readings shall be scheduled for periods of not less than twenty-five (25) days or more than thirty-five (35) days.

2. If the Company is unable to read a meter on the scheduled meter read date, the Company will estimate the consumption for the billing period, giving consideration to the following factors where applicable:

    a. The Customer's usage history in the previous twelve (12) months; and

    b. The amount of usage during the preceding month.

3. After the second consecutive month of estimating the Customer's bill for reasons other than severe weather, the Company will attempt to secure an accurate reading of the meter.

4. Failure on the part of the Customer to comply with a reasonable request by the Company for access to the Customer's meter may lead to the discontinuance of service.

5. Estimated bills will be issued only under the following conditions:

    a. Failure of a Customer who reads his or her own meter to deliver the meter reading card to the Company in accordance with the requirements of the Company's billing cycle;

    b. Severe weather conditions which prevent the Company from reading the meter; or

    c. Circumstances that make it impossible to read the meter, such as locked gates, blocked meters, and vicious or dangerous animals, etc.

6. Each bill based on estimated usage will indicate that it is an estimated bill.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

B. Combining Meters - Minimum Bill Information

1. Each meter at a Customer's premises will be considered separately for billing purposes; and the readings of two (2) or more meters will not be combined unless approved by the Company.

2. Each bill for sales service will contain the following minimum information:

   a. Date and meter reading at the start of billing period or number of days in the billing period;
   b. Date and meter reading at the end of the billing period;
   c. Billed usage;
   d. Rate schedule number;
   e. Company's telephone number;
   f. Customer's name;
   g. Service account number;
   h. Amount due and due date;
   i. Past due amount;
   j. Adjustment factor, where applicable;
   k. Taxes; and
   l. The Arizona Corporation Commission's address.

C. Billing Terms

1. All bills for gas service are due and payable no later than ten (10) days from the date the bill is rendered. Any payment not received within this time-frame shall be considered past due and may be subject to a late payment finance charge as set forth in the Statement of Additional Charges. If the tenth (10th) day falls on a weekend or holiday, then the past due date is extended to the next business day.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

2. For purposes of this rule, the date the bill is rendered shall be the latest of the following:

    a. The postmark date;

    b. The mailing date; or

    c. The billing date shown on the bill (however, the billing date shall not differ from the postmark or mailing date by more than two (2) days.

3. All past due bills for gas service are due and payable within fifteen (15) days. Any payment not received within this time-frame shall be considered delinquent and will be issued a suspension of service notice. For Customers under the jurisdiction of a bankruptcy court, a more stringent payment or prepayment schedule may be required, if allowed by that court.

    a. The amount of the late payment penalty shall not exceed one and one-half percent (1.5%) of the delinquent bill, applied on a monthly basis.

4. All delinquent bills for which payment has not been received within five (5) days shall be subject to the provisions of the Company's suspension of service procedures.

5. All payments shall be made at or mailed to the office of the Company or to the Company's duly authorized representative.

6. A past due payment may be collected by a Company representative at the Customer's premises for a fee as set forth in the Statement of Additional Charges.

D. Applicable Pricing Plans, Prepayments, Failure to Receive, Commencement Date

1. Each Customer shall be billed under the Pricing Plan indicated in the Customer's application for service.

2. The Company shall make provisions for advance payment for Company services.

3. Failure to receive bills or notices which have been properly placed in the United States mail shall not prevent such bills from becoming delinquent and does not relieve the Customer of the Customer's obligations therein.

4. Charges for service commence when the service is installed and connection made, whether used or not.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

E. Meter Error Corrections

1. If, after testing, any meter is found to be more than three percent (3%) in error, either fast or slow, proper correction between three percent (3%) and the amount of the error shall be made on previous readings, and adjusted bills shall be rendered according to the following terms:

    a. For the period of three (3) months immediately preceding the removal of such meter from service for testing or from the time the meter was in service since last tested, but not exceeding three (3) months since the meter shall have been shown to be in error by such test.

    b. From the date the error occurred, if the date of the cause can be definitely fixed.

2. No adjustment shall be made by the Company except to the Customer last served by the meter tested.

F. Nonsufficient Funds ("NSF") Checks and Denied Electronic Funds Transfers

1. The Company shall be allowed to recover a fee set forth in the Statement of Additional Charges, for each instance where a Customer tenders payment for a Company service with an NSF check. This fee shall also apply when an electronic funds transfer ("EFT") is denied for any reason, including for lack of sufficient funds.

2. When the Company is notified by the Customer's bank that there are insufficient funds to cover the check tendered for service, or an EFT has been denied for any reason, the Company may require the Customer to make payment in cash, by money order or certified check, or by other means which guarantee the Customer's payment to the Company.

3. A Customer who tenders an NSF check or for whom an EFT is denied, shall in no way be relieved of the obligation to render payment to the Company under the original terms of the bill, nor defer the Company's provision for termination of service for nonpayment of bills.

4. No personal checks will be accepted if two (2) NSF checks have been received by the Company within a twelve (12) month period in payment of any billing.

G. Elevation/Pressure Adjustment

The Company shall adjust for pressure according to the procedures in Section 8.H of these Rules and Regulations.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

H. Deferred Payment Plan

1. The Company may, prior to termination of service, offer a deferred payment plan to qualifying residential Customers for the payment of unpaid bills for gas service.

2. Each deferred payment agreement entered into by the Company and the Customer, due to the Customer's inability to pay an outstanding bill in full, shall provide that service will not be discontinued if:

    a. The Customer agrees to pay a reasonable amount of the outstanding bill at the time the parties enter into the deferred payment agreement;

    b. The Customer agrees to pay all future bills for gas service in accordance with the Company's Pricing Plans; and

    c. The Customer agrees to pay a reasonable portion of the remaining outstanding balance in installments.

3. For the purposes of determining a reasonable installment payment schedule under these Rules, the Company and the Customer shall give consideration to the following conditions:

    a. The size of the delinquent account;

    b. The Customer's ability to pay;

    c. The Customer's payment history;

    d. The length of time that the debt has been outstanding;

    e. The circumstances which resulted in the debt being outstanding; and

    f. Any other relevant factors related to the circumstances of the Customer.

4. Any Customer who desires to enter into a deferred payment agreement shall establish such agreement prior to the Company's scheduled service termination date for nonpayment of bills. The Customer's failure to execute a deferred payment agreement prior to the scheduled service termination date shall not prevent the Company from terminating service for nonpayment.

5. Deferred payment agreements may be in writing and may be signed by the Customer and an authorized Company representative.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

6. A deferred payment agreement may include a finance charge of one and one-half percent (1.5%) per month.

7. If a Customer does not fulfill the terms of a deferred payment agreement, the Company shall have the right to disconnect service pursuant to the Company's termination of service rules (Section No. 11 of these Rules) and, under such circumstances, it shall not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

I. Change of Occupancy

1. Not less than three (3) business days advance notice must be given in person at the Company's office, in writing, or by telephone to discontinue service or to change occupancy.

2. The outgoing party shall be responsible for all Company services provided and/or consumed up to the scheduled turn-off date.

J. Electronic Billing

Electronic Billing is an optional billing service whereby Customers may elect to receive, view, and pay their bills electronically. Electronic Billing includes the "UES e-bill" service and the "Sure No Hassle Automatic Payment ("SNAP") service. The Company may modify its electronic billing services from time to time. A Customer electing an electronic billing service may receive an electronic bill in lieu of a paper bill. Customers electing an electronic billing service may be required to complete additional forms and agreements. Electronic billing may be discontinued at any time by the Company or the Customer. An electronic bill will be considered rendered at the time it is electronically sent to the Customer. Failure to receive bills or notices which have been properly sent by an electronic billing system does not prevent such bills from becoming delinquent and does not relieve the Customer of the Customer's obligations therein. Any notices which Company is required to send to a Customer who has elected an electronic billing service may be sent by electronic means at the option of the Company. Except as otherwise provided in this subsection, all other provisions of the Company's Rules and Regulations and other applicable Pricing Plans are applicable to electronic billing.

SECTION NO. 11
TERMINATION OF SERVICE

A. Non-Permissible Reasons to Disconnect Service

1. The Company may not disconnect service for any of the reasons stated below:

   a. Delinquency in payment for services rendered to a prior Customer at the premises where service is being provided, except in the instance where the prior Customer continues to reside on the premises.

   b. Failure of the Customer to pay for services or equipment that are not regulated by the ACC.

   c. Nonpayment of a bill related to another class of service.

   d. Failure to pay a bill to correct a previous under-billing due to an inaccurate meter or meter failure, if the Customer agrees to pay over a reasonable period of time.

   e. The Company may not terminate residential service where the Customer has an inability to pay and:

      i. The Customer can establish through medical documentation that, in the opinion of a licensed medical physician, termination of service would be especially dangerous to the health of the Customer or to the health of a permanent resident residing on the Customer's premises;

      ii. Life-supporting equipment is used in the home that is dependent on Company service for operation of such apparatus; or

      iii. Where weather will be especially dangerous to health as defined herein or as determined by the ACC.

   f. Residential service to persons who have an inability to pay and who have an illness, are elderly, or who are handicapped will not be terminated until all of the following have been attempted:

      i. The Customer has been informed of the availability of funds from various government and social assistance agencies; and

      ii. A third party previously designated by the Customer has been notified and has not made arrangement to pay the outstanding Company bill.

   A Customer utilizing the provisions of Subsection A.1.e or A.1.f above may be required to enter into a deferred payment agreement with the Company within ten (10) days after the scheduled service termination date.

   g. Failure to pay the bill of another Customer as guarantor thereof.

   h. Disputed bills where the Customer has complied with the ACC's rules on Customer bill disputes.

SECTION NO. 11
TERMINATION OF SERVICE
(continued)

B. Termination of Service Without Notice

1. The Company may disconnect service without advance written notice under the following conditions:

   a. The existence of an obvious hazard to the safety or health of the Customer, the general population or which imperils service to other Customers;

   b. The Company has evidence of tampering or fraud;

   c. There is an unauthorized resale or use of gas services that is not in accordance with the ACC's rules and/or these Rules and Regulations or other Company Pricing Plans; or

   d. The Customer has failed to comply with the curtailment procedures imposed by the Company in accordance with the Company's Pricing Plans.

2. The Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Company.

3. The Company shall maintain a record of all terminations of service without notice. This record shall be maintained for a minimum of one (1) year and shall be available for inspection by the ACC.

C. Termination of Service With Notice

1. The Company may disconnect service to any Customer for any reason stated below, provided that the Company has met the notice requirements described in Section 11.D below:

   a. Customer violation of any of the Company's Pricing Plans;

   b. Failure of the Customer to pay a delinquent bill for gas service;

   c. Failure of the Customer to meet agreed upon deferred payment arrangements;

   d. Failure to meet or maintain the Company's deposit requirements;

   e. Failure of the Customer to provide the Company reasonable access to its equipment and property;

   f. Customer breach of a written contract for service between the Company and Customer; or

   g. When necessary for the Company to comply with an order of any governmental agency having such jurisdiction.

2. The Company shall maintain a record of all terminations of service with notice. This record shall be maintained for one (1) year and shall be available for ACC inspection.

SECTION NO. 11
TERMINATION OF SERVICE
(continued)

D. Termination Notice Requirements

1. The Company may not terminate service to any of its Customers without providing advance written notice to the Customer of the Company's intent to disconnect service, except under those conditions specified where advance written notice is not required.

2. Such advance written notice shall contain, at a minimum the following information:

   a. The name of the person whose service is to be terminated and the address where service is being rendered;

   b. The Pricing Plan that was violated and explanation of the violation or the amount of the bill, which the Customer has failed to pay in accordance with the payment policy of the Company, if applicable;

   c. The date on or after which service may be terminated; and

   d. A statement advising the Customer that the Company's stated reason for the termination of services may be disputed by contacting the Company at a specific address or phone number, advising the Company of the dispute and making arrangements to discuss the cause for termination with a responsible employee of the Company in advance of the scheduled date of termination. The responsible employee shall be empowered to resolve the dispute and the Company shall retain the option to terminate service after affording this opportunity for a meeting, concluding that the reason of terminating is just, and advising the Customer of his right to file a complaint with the ACC.

3. Where applicable, a copy of the termination notice will be simultaneously forwarded to designated third parties.

E. Timing of Terminations With Notice

1. The Company shall be required to give at least five (5) days advance written notice prior to the termination date. For Customers under the jurisdiction of a bankruptcy court, a shorter notice may be provided, if permitted by that court.

2. Such notice shall be considered to be given to the Customer when a copy of the notice is left with the Customer or posted first class in the United States mail, and addressed to the Customer's last known address.

3. If, after the period of time allowed by the notice has elapsed, the delinquent account has not been paid nor arrangements made with the Company for the payment of the bill, or in the case of a violation of the Company's rules the Customer has not satisfied the Company that such violation has ceased, the Company may terminate service on or after the day specified in the notice without giving further notice.

SECTION NO. 11
TERMINATION OF SERVICE
(continued)

4. Service may only be disconnected in conjunction with a personal visit to the premises by an authorized representative of the Company.

5. The Company shall have the right, but not the obligation, to remove any or all of its property installed on the Customer's premises upon the termination of service.

F. Landlord/Tenant Rule

1. In situations where service is rendered at an address different from the mailing address of the bill or where the Company knows that a landlord/tenant relationship exists and that the landlord is the Customer of the Company, and where the landlord as Customer would otherwise be subject to disconnection of service, the Company may not disconnect service until the following actions have been taken:

   a. Where it is feasible to provide service, the Company, after providing notice as required in these rules, shall offer the occupant the opportunity to subscribe for service in the occupant's own name. If the occupant then declines to subscribe, the Company may disconnect service pursuant to the rules.

   b. The Company shall not attempt to recover payment of any outstanding bills or other charges due on the outstanding account of the landlord from a tenant. The Company shall not condition service to a tenant based on the payment of any outstanding bills or other charges due upon the outstanding account of the landlord.

SECTION NO. 12
ADMINISTRATIVE AND HEARING REQUIREMENTS

A. Customer Service Complaints

1. The Company shall make a full and prompt investigation of all service complaints made by its Customers, either directly to the Company or through the ACC.

2. The Company shall respond to the complainant and/or the ACC representative within five (5) business days as to the status of the Company's investigation of the complaint.

3. The Company shall notify the complainant and/or the ACC representative of the final disposition of each complaint. Upon request of the complainant or the ACC representative, the Company shall report the findings of its investigation in writing.

4. The Company shall inform the Customer of the right of appeal to the ACC.

5. The Company shall keep a record of all written service complaints received and which shall contain, at a minimum, the following data:

    a. Name and address of complainant;

    b. Date and nature of complaint;

    c. Disposition of the complaint; and

    d. A copy of any correspondence between the Company, the Customer, and/or the ACC.

This record shall be maintained for a minimum period of one (1) year and shall be available for inspection by the ACC.

SECTION NO. 12
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

B. Customer Bill Disputes

1. Any Customer who disputes a portion of a bill rendered for gas service shall pay the undisputed portion of the bill prior to the delinquent date of the bill, and notify the Company's designated representative that any unpaid amount is in dispute.

2. Upon receipt of the Customer's notice of dispute, the Company shall:

   a. Notify the Customer within five (5) business days of the receipt of a written dispute notice.

   b. Initiate a prompt investigation as to the source of the dispute.

   c. Withhold disconnection of service until the investigation is completed and the Customer is informed of the results. Upon request of the Customer, the Company shall report the results of the investigation in writing.

   d. Inform the Customer of the right of appeal to the ACC.

3. Once the Customer has received the results of the Company's investigation, the Customer shall submit payment within five (5) business days to the Company for any disputed amounts. Failure to make full payment shall be grounds for termination of service.

C. ACC Resolution of Service and/or Bill Disputes

1. In the event a Customer and the Company cannot resolve a service and/or bill dispute, the Customer shall file a written statement with the ACC. By submitting such written notice to the ACC, the Customer shall be deemed to have filed an informal complaint against the Company.

SECTION NO. 12
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

2. Within thirty (30) days of the receipt of a written statement of Customer dissatisfaction related to a service or bill dispute, a designated representative of the ACC shall endeavor to resolve the dispute by correspondence and/or by telephone with the Company and the Customer. If resolution of the dispute is not achieved within twenty (20) days of the ACC representative's initial effort, the ACC shall hold an informal hearing to arbitrate the resolution of the dispute. The informal hearing shall be governed by the following rules:

    a. Each party may be represented by legal counsel, if desired;

    b. All such informal hearings may be recorded or held in the presence of a stenographer;

    c. All parties will have the opportunity to present written or oral evidentiary material to support the positions of the individual parties; and

    d. All parties and the ACC's representative shall be given an opportunity for cross-examination of the various parties.

    The ACC's representative will render a written decision to all parties within five (5) business days after the date of the informal hearing. Such written decision of the ACC's representative is not binding on any of the parties and the parties will still have the right to make a formal complaint to the ACC.

3. The Company may implement normal termination procedures if the Customer fails to pay all bills rendered during the resolution of the dispute by the ACC.

4. The Company shall maintain a record of written statements of dissatisfaction and their resolution for a minimum of one (1) year and make such records available for ACC inspection.

D. Notice by Company of Responsible Officer or Agent

1. The Company shall file with the ACC a written statement containing the name, business address and telephone numbers (office and mobile) of at least one officer, agent or employee responsible for the general management of its operations as a Company in Arizona.

2. The Company shall give notice, by filing a written statement with the ACC, of any change in the information required herein within five (5) days from the date of any such change.

SECTION NO. 13
BUDGET BILLING PAYMENT PLAN

A. The Company may, at its option, offer its Customers Budget Billing Payment Plan ("Plan") for payment of charges for gas service.

B. The Company will develop, upon Customer request, an estimate of the Customer's levelized billing for a twelve (12) month period based on:

1. The Customer's actual consumption history at the service location, which may be adjusted for weather or other known variations. If sufficient history is not available, then an estimate will be prepared based on other similar service locations and Customer's anticipated load requirements; and

2. The applicable Pricing Plan, the estimated gas costs for the Plan year, and applicable taxes.

C. The Company shall provide the Customer with a concise explanation of how the levelized billing estimate was developed, the impact of levelized billing on a Customer's monthly bill, and the Company's right to adjust the Customer's billing for any variation between the Company's estimated billing and actual billing.

D. The Plan's monthly payment shall be determined as follows: Settlement month will be the Customer's anniversary date, twelve (12) months from the time the Customer is set up on the Budget Billing Payment Plan. The Company reserves the right to adjust the remaining monthly Plan semi-annually to reduce the likelihood of an excessive debt or credit balance in rates due to dramatic PGA increases or PGA surcharges.

1. The Company reserves the right to adjust the remaining monthly Plan payments of any Customer at any time if the Company's estimate of the Customer's usage and/or cost varies significantly from the Customer's actual usage and/or cost. Such review may also be initiated by the Customer. Any change resulting from such a review will be effective on a subsequent bill and no further notice is required.

2. The Customer shall continue to pay the monthly Plan payment amount each month, notwithstanding the current gas service charge shown on the bill.

3. Any other charges incurred by the Customer shall be paid monthly when due in addition to the monthly Plan payment.

4. Interest will not be charged to the Customer on accrued debit balances nor paid by the Company on accrued credit balances.

5. Any amount due the Company will be settled and paid at the time a Customer, for any reason, ceases to be a participant in the Plan. If an amount due to the Customer exceeds fifty dollars ($50.00), the Customer has the option to receive a bill credit or a refund; otherwise the credit will remain as a bill credit.

SECTION NO. 13
BUDGET BILLING PAYMENT PLAN
(continued)

6. Any Customer's participation in the Plan may be discontinued by the Company if the monthly Plan payment has not been paid on or before the billing date of the next monthly Plan payment.

7. If a Customer in the Plan shall cease, for any reason, to participate in the Plan, then the Company may refuse that Customer's re-entry in the Plan for six (6) months.

8. For those Customers being billed under the Plan, the Company shall show, at a minimum, the following information on the Customer's monthly bill:

   a. Actual consumption;

   b. Amount due for actual consumption;

   c. Levelized billing amount due; and

   d. Accumulated variation in actual versus levelized billing amount.

SECTION NO. 14
CURTAILMENT PLAN

A. The Company shall use reasonable diligence in its operations to render continuous service to all its Customers other than those Customers served under Pricing Plans expressly permitting interruptions of service for peak shaving purposes. If for any reason, however, the Company is unable to supply the demand for gas in any one or more of its systems, interruptions or curtailments of service shall be made in accordance with the provisions of this section. The Company shall not be liable for damages because of the operation of this section.

B. Applicability

1. The order of curtailment shall be in inverse order of the curtailment priorities set forth in Subsection C below.

2. Curtailment priorities shall apply to both sales and transportation Customers.

3. Customers being served under a discounted transportation or sales rate schedule shall be curtailed first. Customers paying the least will be curtailed first within an affected priority.

4. Each priority shall be curtailed in full before the next priority in order is curtailed.

5. When Priority 1 Customers would be curtailed due to system supply failure (either upstream capacity or supply failure), the Company is authorized to "preempt" deliveries of lower priority transportation Customers' gas and divert such supplies to the otherwise affected Priority 1 Customers. Affected transportation Customers will be curtailed to the same extent as sales Customers of the same priority. Such transportation Customers will be compensated for the preemption of their gas supply by either crediting the Customer's account with a like quantity of gas for use on a subsequent gas day, or by providing a cash payment or credit to the Customer's bill at the cost of gas per unit paid by the Customer. If the gas supply of an alternate fuel-capable transportation Customer is preempted according to this provision, the Company shall provide additional compensation to such Customer for the incremental cost of using the alternate fuel, (the difference between the actual cost of using the alternate fuel and the actual cost of gas paid by the Customer for the preempted gas). Such credit shall be applied to the Company's next scheduled billing after the Customer has furnished adequate proof to the Company concerning alternate fuel costs, replacement volumes, and gas costs.

6. The installation of a cogeneration facility shall not affect the underlying end-use priority of the establishment.

7. Natural gas utilized as compressed natural gas for vehicle fuel shall be classified as a commercial end-use.

SECTION NO. 14
CURTAILMENT PLAN
(continued)

8. Application of curtailment priorities will normally be done on a scheduled basis as part of the daily gas requirement nomination and confirmation routine. Operational emergency curtailment will conform to these priorities to the extent possible and practical.

9. A transportation Customer may be curtailed to the level of actual supply scheduled for that Customer, regardless of end-use priority.

C. Priorities

Priority 1: Residential, small commercial (less than five hundred (500) therms on a peak day), schools, hospitals, police protection, fire protection, sanitation facility, correctional facility, and emergency situation uses.

Priority 2A: Essential agricultural uses as certified by the Secretary of Agriculture.

Priority 2B: Essential industrial process and feedstock uses.

Priority 2C: Large Commercial (five hundred (500) therms or more on a peak day) and storage injection requirements, industrial requirements for plant protection, feedstock, process, ignition and flame stabilization needs not specified in Priority 2B.

Priority 3A: Industrial requirements not specified in Priorities 2, 4, and 5, of less than one thousand (1,000) therms on a peak day.

Priority 3B: All industrial requirements not specified in Priorities 2, 3A, 4, and 5.

Priority 4: Industrial requirements for boiler fuel use at less than thirty thousand (30,000) therms per peak day, but more than fifteen thousand (15,000) therms per peak day, where alternate fuel capabilities can meet such requirements.

Priority 5: Industrial requirements for large volume (thirty thousand (30,000) therms per peak day or more) boiler fuel use where alternate fuel capabilities can meet such requirements.

D. In the event of isolated incidents in order to avoid hazards and protect the public, the Company may temporarily interrupt service to certain Customers without regard to priority or any other Customer classification.

SECTION NO. 14
CURTAILMENT PLAN
(continued)

E. Definitions

1. "Alternate Fuel Capability" – A situation where an alternate fuel can be utilized whether or not the facilities for such use have actually been installed.

2. "Correctional Facility Uses" – A facility, the primary function of which is to house, confine, or otherwise limit the activities of a person who has been assigned to such facilities as punishment by a court of law.

3. "Essential Agricultural Use" – Any use of natural gas which is certified by the Secretary of Agriculture as an "essential agricultural use.

4. "Essential Industrial Process and Feedstock Uses" – Any use of natural gas by an industrial Customer as process gas, or as a feedstock, or gas used for human comfort to protect health and hygiene in an industrial installation.

5. "Feedstock Gas" – Natural gas use for which alternate fuels are not technically feasible, such as in applications requiring precise temperature controls and precise flame characteristics. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

6. "Fire Protection Uses" – Natural gas used by and for the benefit of fire fighting agencies in the performance of their duties.

7. "Flame Stabilization Gas" – Natural gas which is burned by igniters, main gas burners, or warm-up burners for the purpose of maintaining stable combustion of an alternate fuel.

8. "Hospital" – A facility, the primary function of which is delivering medical care to patients who remain at the facility (facility includes nursing and convalescent homes). Outpatient clinics or doctors' offices are not included in this definition.

9. "Ignition Gas" – Natural gas supplied to gas igniters in boilers to light main burners, whether the main burners are operated by gas, oil, or coal.

10. "Industrial Boiler Fuel" – Natural gas used in a boiler as a fuel for the generation of steam or electricity.

11. "Industrial Use" – Natural gas used primarily in a process which creates or changes raw or unfinished materials into another form or product, including electric power generation.

12. "Peak Day" – Maximum daily Customer use as determined by the best practical method available.

SECTION NO. 14
CURTAILMENT PLAN
(continued)

13. "Plant Protection Gas" – Minimum natural gas volumes required to prevent physical harm to the plant facilities or danger to plant personnel when such protection cannot be afforded through the use of an alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not include deliveries required to maintain plant production. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

14. "Police Protection Uses" – Natural gas used by law enforcement agencies in the performance of their duties.

15. "Process Gas" – Natural gas use for which alternate fuels are not technically feasible, such as in applications requiring precise temperature controls and precise flame characteristics. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

16. "Sanitation Facility Uses" – Natural gas use in a facility where natural gas is used to a) dispose of refuse, or b) protect and maintain the general sanitation requirements of the community at large.

17. "School" – A facility, the primary function of which is to provide instruction to regularly enrolled students in attendance at such facility. Facilities used for both educational and non-educational activities are not included under this definition unless the latter activities are merely incidental to the provision of instruction.

18. "Small Commercial Establishment" – Any establishment (including institutions and local, state, and federal government agencies) engaged primarily in the sale of goods or services where natural gas is used:

    a. in amounts of less than fifty (50) MCF on a peak day; and

    b. for purposes other than those involving manufacturing or electric power generation.

19. "Storage Injection Gas" – Natural gas injected by a distributor into storage for later use.

SECTION NO. 15
RATES AND UNIT MEASUREMENT

A. The rates and charges for gas service shall be those of the Company legally in effect and on file with the ACC.

B. All rates set forth in the Company's Pricing Plans are stated in therms. Unless otherwise provided by special contract, the number of therms delivered to any Customer shall be determined by measuring the volume of gas passing through that Customer's meter during the month to the nearest one hundred (100) cubic feet and applying the procedures of Section 8.H of these Rules and Regulations.

C. The unit of volume for measurement of gas sold shall be one (1) Cubic Foot of gas, as defined in Section 2, Subsection A.13 of these Rules and Regulations. The volume of gas measured shall be rounded to the nearest one hundred (100) cubic feet for any given period.

D. The atmospheric pressure will be the standard atmospheric pressure for the location.

E. The standard serving pressure shall be seven (7) inches of water pressure (four (4) ounces per square inch gauge) above the atmospheric pressure.

F. The standard temperature of sixty (60) degrees Fahrenheit will be used for volume determination unless stated otherwise under special contract. The Company shall retain the right, but shall not be obligated, to install temperature recording or compensating equipment as part of the measuring facilities. When such temperature recording equipment is used, the arithmetic average temperature of the gas each day, during periods of flow only, shall be used in computing the quantity of gas delivered by that day.

G. The Company, at its own option, may elect to serve a Customer at a pressure higher than the standard serving pressure. The Company shall correct such volume to Standard Conditions by the use of compensating equipment or the use of a factor. The Company retains the right to determine the method used for applying such correction. The factor used to correct the measured volume shall be in accordance with American Gas Association Report 3.

H. The therm conversion factor shall be determined each month and shall be the product of the conversion factor and the most recent heating value content available using the weighted average delivered pressure by office. The weighted average delivered pressure is derived monthly using the delivered pressure for each town code served which is reflective of each town code's elevation, weighted by the sales distribution among assigned gas distribution systems within each respective office. Further explained in Section 8.H. of these Rules and Regulations.

SECTION NO. 16
GAS METER TESTING AND MAINTENANCE PLAN

A. General Plan

The Company will annually sample groups of meters to determine the continuing accuracy and performance of the group. Certain safe and proper standards are defined, and meters will remain in service as long as they meet these standards. This program will allow the Company to obtain all the useful service available from a meter until the meter no longer meets prescribed standards. At that time, then it is proper for the meter to be removed, tested, repaired, or retired.

This procedure is for the purpose of testing and controlling the performance of small gas meters that are two hundred fifty (250) CFH or less. The program will identify and remove meters that do not meet the standards of performance described in Subsection D below, and identify and retain in service meters that do meet or exceed the stated standards. Meters are classified into groups, samples of each group are tested annually, and groups are removed from service when they do not meet performance standards.

B. Meter Groups

1. Meters are segregated into groups on the following basis:

    a. Year last repaired or purchased;

    b. Manufacturer;

    c. Diaphragm type (leather or synthetic), when available; and

    d. Geographic district.

2. For meters repaired or purchased in a given year, the groups are established at the beginning of the next year. When a new group being established is found to contain less than one thousand (1,000) meters, this group may be combined with another group having meters of the same or similar operating characteristics. An existing group may be divided into two or more groups, if experience characteristics of part of the group are sufficiently different from the remainder of the group to warrant separate sampling of the parts.

C. Sampling

A representative random sample is selected from each group of meters. The samples are used in determining the performance of each group of meters each year. If the initial order for meter removals does not produce an adequate sample, additional meters are drawn on a random basis. These meters are combined with the original sample for determining acceptability of the group. Samples are taken annually from all groups that have been in service for ten years or longer.

SECTION NO. 16
GAS METER TESTING AND MAINTENANCE PLAN
(continued)

D. Performance Standard

The criteria for acceptability for a group to remain in service are:

1. No more than ten percent (10%) of the meters tested in the group are more than three percent (3%) fast.

2. At least eighty percent (80%) of the meters tested in the group are within +/- three percent (3%) of zero error. This results in a condition wherein a minimum of ninety percent (90%) of the meters remaining in service are either within +/- three percent (3%) or are more than three percent (3%) slow and in the Customer's favor.

E. Records

The test results for each group are kept in appropriate records that indicate the number of meters in the sample versus the test results, expressed as a percent.

F. Removal of Groups

1. A test result falling on or above the prescribed standards is satisfactory and the groups will remain in service.

2. A test falling below the prescribed standards is not satisfactory and the group will be removed from service.

3. The Company, for its convenience, may remove a group (or part of a group) even though the group meets the requirements for remaining in service.

SECTION NO. 16
GAS METER TESTING AND MAINTENANCE PLAN
(continued)

G. Annual Reports

A report of the meter performance control program will be filed annually with the ACC, which will contain the following:

1. A description of each group, showing its identification, size and composition;

2. A list of the total number of meters tested, at Company initiative or upon Customer request;

3. A detailed list of the performance results of each group, showing the number of meters in the group, the number of meters removed during the year, the number of meters not tested (dead, non-registering, damaged, etc.), the number or meters tested, the number of meters slow - minus three percent (-3%), the number of meters accurate, the percent of meters accurate, the number of meters fast - plus three percent (+3%), and the percent of meters fast;

4. A summary of results for each year of service; and

5. A summary or the overall results.

SECTION 17
STATEMENT OF ADDITIONAL CHARGES

A.	Trip Charge:	
	1. Service Transfer	$20.00
	2. Collection Fee	$20.00
	3. Customer-Requested Meter Reread	$20.00
	4. Multiple Attempts to Connect	$20.00
B.	Service Establishment, Re-establishment, or Reconnection	
	During Regular Business Hours	$35.00
	After Regular Business Hours (same day request scheduled)	$50.00
C.	Special Call Out (Minimum one (1) hour)	
	Per hour	$70.00
D.	Customer-Requested Meter Test	$90.00
E.	NSF Check	$10.00
F.	Late Payment Finance Charge	1.5%
G.	Interest on Customer Deposits	One-year Treasury Constant Maturities rate

Regular Business Hours are defined as non-holiday weekdays from 8:30 a.m. to 4:30 p.m.

EXHIBIT

GAS-1B

REDLINED VERSION

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SECTION NO. 1
APPLICABILITY OF RULES AND REGULATIONS AND DESCRIPTION OF SERVICE

A. Company is a gas utility operating within portions of the state of Arizona. The Company will provide service to any person, institution or business located within its service area in accordance with the provisions of its Pricing Plans and the terms and conditions of these Rules and Regulations.

B. All gas delivered to any Customer is for the sole use of such Customer on that Customer's premises only. Gas delivered by the Company shall not be redelivered or resold, or the use thereof by others permitted unless otherwise expressly agreed to in writing by the Company. However, those Customers purchasing gas for redistribution to the Customer's own tenants (only on the Customer's premises) may separately meter each tenant distribution point for the purpose of prorating the Customer's actual purchase price of gas delivered among the various tenants on a per unit basis.

C. These Rules and Regulations shall apply to all gas service furnished by the Company to its Customers.

D. These Rules and Regulations are part of the Company's Pricing Plans on file with and duly approved by, the Arizona Corporation Commission. These Rules and Regulations shall remain in effect until modified, amended, or deleted by order of the ACC. No employee, agent or representative of the Company is authorized to modify the Company rules.

E. These Rules and Regulations shall be applied uniformly to all similarly situated Customers.

F. In case of any conflict between these Rules and Regulations and the ACC's rules, these Rules and Regulations shall apply.

G. Whenever the Company and an Applicant or a Customer are unable to agree on the terms and conditions under which such Applicant or Customer is to be served, or are unable to agree on the proper interpretation of the these Rules and Regulations, either party may request assistance from the Consumer Services Section of the Utilities Division of the ACC. The Applicant or Customer also has the option to file an application with the ACC for a proper order, after notice and hearing.

H. The Company's supplying gas service to the Customer and the acceptance thereof by the Customer shall be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for gas service under the Company's Rules and Regulations and applicable Pricing Plans.

SECTION NO. 2
DEFINITIONS

~~a.~~A. In these Rules and Regulations, the following definitions shall apply unless the context requires otherwise:

1. "Advance in Aid of Construction" or "Advance" – Funds provided to the Company by an Applicant under the terms of a main extension agreement, the value of which may be refundable.

2. "Applicant" – A person requesting the Company to supply gas service.

3. "Application" – A request to the Company for gas service, as distinguished from any inquiry as to the availability or charges for such service.

4. "Arizona Corporation Commission" ("ACC") – The regulatory body established by Article XV of the Arizona Constitution.

5. "Billing Month" – The time interval between any two (2) regular readings of the Company's meters at approximately thirty (30) day intervals.

6. "Billing Period" – The time period between two (2) consecutive meter readings that are taken for billing purposes.

7. "British Thermal Unit" ("BTU") – The amount of heat required to raise the temperature of one (1) pound of water one (1) degree Fahrenheit, at Standard Conditions.

8. "CCF" – One hundred (100) cubic feet.

9. "CFH" – Cubic feet per hour.

10. "Commodity Charge" – The unit cost for billed usage as set forth in the Company's Pricing Plans.

11. "Company" – UNS Gas, Inc.

12. "Contributions in Aid of Construction" or "Contribution" – Funds provided to the Company by the Applicant under the terms of a main extension agreement and/or service connection tariff, the value of which are not refundable.

SECTION NO. 2
DEFINITIONS
(continued)

13. "Cubic Foot" –

a. In cases where gas is supplied and metered to Customers at Standard Delivery Pressure, a cubic foot of gas is the volume of gas, which at the temperature and pressure existing in the meter occupies one (1) cubic foot.

b. Regardless of the pressure supplied to the Customer, the volume of gas metered will be converted to the volume which the gas would occupy at Standard Conditions.

c. The standard cubic foot of gas used for testing the gas for heating value shall be that volume of gas which, when saturated with water vapor and at a temperature of sixty (60) degrees Fahrenheit and under a pressure equivalent to that of thirty (30) inches of mercury (mercury at thirty-two (32) degrees Fahrenheit and under standard gravity), occupies one (1) cubic foot.

14. "Curtailment Priority" – The order in which gas service is to be curtailed to various classifications of Customers, as set forth in the Company's Pricing Plans.

15. "Customer" – The person in whose name service is rendered, as evidenced by the signature on the application or contract for that service, or by the receipt and/or payment of bills regularly issued in the person's name regardless of the identity of the actual user of the service.

16. "Customer Charge" – The amount the Customer must pay the Company for the availability of gas service, excluding any gas used, as specified, in the Company's Pricing Plans.

17. "Customer Service Complaint" - Written complaint received from a Customer, or through the ACC on behalf of a Customer.

18. "Day" – Calendar day.

19. "Decatherm" – Ten (10) therms or one million (1,000,000) BTUs.

20. "Distribution Main" – A gas line of the Company from which service lines may be extended to Customers.

21. "Elderly" – A person who is sixty-two (62) years of age or older.

22. "Excess Flow Valve" ("EFV") – A device that is designed to restrict the flow of gas in a single family residence natural gas service line by automatically closing in the event that it is broken downstream of the EFV, completely cut, torn apart or otherwise separated, usually caused by some type of excavation or digging activity.

SECTION NO. 2
DEFINITIONS
(continued)

~~21.~~23. "Handicapped" – A person with a physical or mental condition which substantially contributes to the person's inability to manage his or her own resources, carry out activities of daily living, or protect themselves from neglect or hazardous situations without assistance from others.

~~22.~~24. "Illness" – A medical ailment or sickness for which a residential Customer obtains a verifiable document from a licensed medical physician stating the nature of the illness and that discontinuance of service would be especially dangerous to the Customer's health.

~~23.~~25. "Inability to Pay" – Circumstances where a residential Customer:

~~1.~~a. Is not gainfully employed and is unable to pay; or

~~2.~~b. Qualifies for government welfare assistance, but has not begun to receive assistance on the date that the bill is received and can obtain verification from the government welfare agency; or

~~3.~~c. Has an annual income below the published federal poverty level and can produce evidence of this; and

~~4.~~d. Signs a declaration verifying that the Customer meets one of the above criteria and is either ~~a senior citizen~~elderly, handicapped, or suffers from an illness.

~~24.~~26. "Incremental Contribution Study" ("ICS") – The study described in Section 7.B.4 of these Rules and Regulations.

~~25.~~27. "Interruptible Gas Service" – Gas service that is subject to interruption or curtailment as specified in the Company's Pricing Plans.

~~26.~~28. "Law" – Any rule or requirement established and enforced by government authorities.

~~27.~~29. "Main Extension" – The lines and equipment necessary to extend the existing gas distribution system to provide service to additional Customers.

~~28.~~30. "Master Meter" – An instrument for measuring or recording the flow of gas at a single location from which said gas is transported through a piping system to tenants or occupants for their individual consumption.

~~29.~~31. "MCF" – One thousand (1,000) cubic feet.

~~30.~~32. "Meter" – The instrument for measuring and indicating or recording the volume of gas that has passed through it.

~~31.~~33. "Meter Set Assembly" ("MSA") – All gas components downstream of the Customer's inlet service valve to the Customer's ~~P~~point of ~~D~~delivery.

SECTION NO. 2
DEFINITIONS
(continued)

~~32.~~34. "Minimum Charge" – The amount the Customer must pay for the availability of gas service and may include an amount of usage, as specified in the Company's Pricing Plans.

~~33.~~35. "Permanent Customer" – A Customer who is a tenant or owner of a service location who applies for and receives gas service.

~~34.~~36. "Permanent Service" – Service which, in the opinion of the Company, is of a permanent and established character. The use of gas may be continuous, intermittent, or seasonal in nature.

~~35.~~37. "Person" – Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.

~~36.~~38. "Point of Delivery" – The ~~P~~point of ~~D~~delivery for all gas delivered to any Customer shall be at the point of interconnection between the facilities of the Company and those of such Customer.

~~37.~~39. "Premises" – All of the real property and apparatus employed in a single enterprise or residence on an integral parcel of land undivided by public streets, alleys or railways.

~~38.~~40. "Pricing Plan" – A part of the Company's Tariffs which sets forth the rates and charges related to specific categories of Customers, and related terms and conditions.

~~39.~~41. "Residential Subdivision" – Any tract of land which has been divided into four or more contiguous lots for use in the construction of residential buildings or permanent mobile homes for either single or multiple occupancy.

~~40.~~42. "Residential Use" – Service to Customers using gas for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, and other residential uses and includes use in apartment buildings, mobile home parks, and other multi-unit residential buildings.

~~41.~~43. "Restricted Apparatus" – An apparatus prohibited by the ACC, another governmental agency, or the Company.

~~42.~~44. "Rules and Regulations" or "Company Rules" – These Rules and Regulations, which are part of the Company's Tariffs and Pricing Plans.

SECTION NO. 2
DEFINITIONS
(continued)

~~43. "Senior Citizen" – A person who is sixty-two (62) years of age or older.~~

44.45. "Service Areas" – The territory in which the Company has been granted a certificate of convenience and necessity and is authorized by the ACC to provide gas service.

45.46. "Service Establishment Charge" – A charge as specified in the Company's Pricing Plans which covers the cost of establishing a new account.

46.47. "Service Line" – A gas pipe that transports gas from a common source or supply (normally a distribution main) to the Customer's pPoint of Ddelivery.

47.48. "Service Reconnection Charge" – A charge specified in the Company's Pricing Plans that must be paid by the Customer prior to re-establishment of gas service each time the gas is disconnected for nonpayment, or for failure to comply with the Company's Pricing Plans. In addition to the Service Reconnection Charge, such returning Customer shall pay the sum of the applicable monthly Customer Charges which would have accrued had the Customer not been disconnected for non-payment or for failure to comply with the Company's Pricing Plans within the preceding twelve (12) month period.

48.49. "Service Re-establishment Charge" – A charge specified in the Company's Pricing Plans for the re-establishment of service at the same location where the same Customer had ordered a service disconnect within the preceding twelve (12) month period. In addition to the Service Re-establishment Charge, such returning Customer shall pay the sum of the applicable monthly Customer Charges which would have accrued had the Customer not ordered the disconnect.

50. "Service Transfer" – Transfer of service from one Customer to another, when the meter is not turned off.

49.51. "Single Family Dwelling" – A house, an apartment, or a mobile home permanently affixed to a lot, or any other permanent residential unit which is used as permanent home.

52. "Special Call-Out" – When Company personal is on-call and is called in from home at the request of the Customer in order to provide service.

50.53. "Standard Conditions" – 14.73 pounds per square inch absolute at sixty (60) degrees Fahrenheit.

51.54. "Standard Delivery Pressure" – 0.25 pounds per square inch gauge at the meter or Ppoint of Ddelivery.

52.55. "Tampering" – A situation where a meter has been illegally altered. Common examples are meter bypassing and other unauthorized connections. Tampering also includes any action defined as "tampering" under A.R.S. § 40-491(4).

~~53.~~56. "Tariffs" – The documents filed with the ACC that list the services offered by the Company and set forth the terms and conditions and a schedule of the rates and charges for those services and products. These Rules and Regulations are part of the Company's Tariffs. The Company's Pricing Plans are also part of the Company's Tariffs.

SECTION NO. 2
DEFINITIONS
(continued)

~~54.~~57. "Temporary Service" – Service to premises or enterprises that are temporary in character, or where it is known in advance that the service will be of limited duration. Service that, in the opinion of the Company, is for operations of speculative character is also considered temporary service.

~~SECTION NO. 2~~
~~DEFINITIONS~~
~~(continued)~~

~~55.~~58. "Therm" – A unit of heating value, equivalent to one hundred thousand (100,000) BTUs.

~~56.~~59. "Third Party Notice" – A notice sent to a person willing to receive notification of the pending discontinuance of service to a Customer of record, in order to make arrangements on behalf of said Customer that are satisfactory to the Company.

~~57.~~60. "Transmission Line" - A gas line for delivering natural gas that operates at a hoop stress of twenty percent (20%) or more of Specified Minimum Yield Strength ("SMYS"), as defined in CFR 49, Part 192 or that transports gas to a single large volume Customer such as a distribution center, factory, power plant or institutional user.

61. "Trip Charge" – Charges set forth in the Company's Statement of Additional Charges for services such as a Service Transfer, Collection Fee, Customer-Requested Meter Re-read, or Multiple Attempts to Connect.

~~58.~~62. "Unauthorized" – Use of gas services that is not in accordance with ACC rules, the Company's Rules and Regulations, or the Company's Pricing Plans.

~~59.~~63. "Weather Especially Dangerous to Health" – That period of time, commencing with the scheduled termination date, when the local weather forecast as predicted by the National Oceanic and Atmospheric Administration, indicates that the temperature will not exceed thirty-two (32) degrees Fahrenheit for the next day's forecast. The ACC may determine that other weather conditions are especially dangerous to health as the need arises.

~~60. "Working Hours" – The period of time during which the Company's offices are open for business.~~

~~61.~~64. "Yardline" – A gas pipe that transports gas from the Customer's ~~P~~point of ~~D~~delivery to the point of entry into the Customer's residence or other place of consumption.

SECTION NO. 3
ESTABLISHMENT OF SERVICE

A. Information From Applicants

~~d.~~1. The Company may obtain the following minimum information from each Applicant:

a. Name or names of Applicant(s);
b. Service address or location and telephone number;
c. Billing address or location and telephone number, if different than service address;
d. Address where service was provided previously;
e. Date Applicant will be ready for service;
f. Indication of whether premises have been supplied with gas service previously;
g. Purpose for which service is to be used;
h. Indication of whether Applicant is owner or tenant of or agent for, the premises;
i. Information concerning the gas usage and demand requirements of the Customer; and
j. Type and kind of life-support equipment, if any, used by the Customer.

~~e.~~2. The Company may require a new Applicant for service to appear at the Company's designated place of business to produce proof of identity and sign the Company's application form.

~~f.~~3. Where service is requested by two or more individuals, the Company shall have the right to collect the full amount owed to the Company from any one of the Applicants.

~~g.~~4. An Applicant for gas service to new construction or a new extension shall complete the following Company forms:

a. New Service Application Form

The Customer is responsible for completing and returning the Application form. Failure on the part of the Customer to provide a completed form shall be grounds for the Company to delay or refuse service. For the purpose of this Rule, the definition of new construction/extension is where there is a need to run a new service line or install new gas facilities to a property that has never had prior natural gas service.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

B. Deposits

1. The Company may require from any present or prospective Customer a security deposit to guarantee payment of all bills. This deposit may be retained by the Company until service is discontinued and all bills have been paid; except as provided in Subsection B.4 below. Upon proper application by the Customer, the Company shall then return said deposit, together with any unpaid interest accrued thereon from the date of commencement of service or the date of making the deposit, whichever is later. The Company shall be entitled to apply said deposit together with any unpaid interest accrued thereon, to any indebtedness for the same class of service owed to the Company for gas service furnished to the Customer making the deposit. When said deposit has been applied to any such indebtedness, the Customer's gas service may be discontinued until all such indebtedness of the Customer is paid and a like deposit is again made with the Company by the Customer. No interest shall accrue on any deposit after discontinuance of the service to which the deposit relates.

   The Company shall not require a deposit from a new Applicant for residential service if the Applicant is able to meet any of the following requirements:

   ~~A.~~a. The Applicant has had service of a comparable nature with the Company at another service location within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months, or was not disconnected for nonpayment; or

   ~~B.~~b. The Applicant can produce a letter regarding credit or verification from a gas or electric utility which states that the Applicant has had service of a comparable nature with that utility at another service location within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months, or was not disconnected for nonpayment; or

   ~~C.~~c. In lieu of a cash deposit, a new Applicant may provide a Letter of Guarantee from an existing Customer of the Company who is acceptable to the Company, a surety bond, or similar alternative acceptable to the Company, such as a Certificate of Deposit, as security for Company in the sum equal to the required deposit; or

   ~~D.~~d. If a credit check is offered by the Company, the Applicant authorizes a credit check and meets the standards established by the Company.

2. The Company may issue a non-assignable, non-negotiable receipt to the Applicant for the deposit. The inability of the Customer to produce such a receipt shall in no way impair the Customer's right to receive a refund of the deposit which is reflected on the Company's records.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

3. Cash deposits held by the Company twelve (12) months or longer shall earn interest at the established one-year Treasury Constant Maturities rates, effective on the first business day of each year, as published in the Federal Reserve website. No interest will be paid on deposits for which Customers have turned service on and off within the same calendar month. Such payment of interest shall be made during January of each year for Customers served by the Company for at least six (6) months and will cover all interest accrued up to the end of the preceding calendar year or on the date the deposit is returned to the Customer, pursuant to Subsection B.4 below. At the Company's option, the above payments may be made either by check or by credit on the monthly bill.

4. All deposits of residential or commercial Customers received and held by the Company shall be returned to the Customer by the Company (with interest, as provided by Subsection B.3 above), at such time as the affected Customers shall have maintained for a period of twelve (12) consecutive months (from and after the date when the deposit was made), their accounts with the Company. The Customer's accounts shall have been maintained in such a manner that they shall not have been delinquent in the payment of more than two (2) bills during such twelve (12) month period, whether at the same address or at a different address, nor have had their gas service, whether at the same address or at a different address, discontinued, in accordance with these Rules and Regulations, for failure to pay for gas service previously rendered.

5. The Company may require a Customer to establish or reestablish a deposit if the Customer became delinquent in the payment of three (3) or more bills within a twelve (12) consecutive month period, or has been disconnected from service during the last twelve (12) months.

6. The Company may review the Customer's usage after service has been connected and adjust the deposit amount based upon the Customer's actual usage.

7. A separate deposit may be required for each meter installed.

8. Residential Customer deposits shall not exceed two (2) times that Customer's estimated average monthly bill. Non-residential Customer deposits shall not exceed two and one-half (2.5) times that Customer's maximum estimated monthly bill. If actual usage history is available, then that usage, adjusted for normal weather, will be the basis for the estimate.

9. The posting of a deposit shall not preclude the Company from terminating service when the termination is due to the Customer's failure to perform any obligation under the agreement for service or any of these Rules and Regulations.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

C. Grounds For Refusal Of Service

The Company may refuse to establish service if any of the following conditions exist:

1. The Applicant has an outstanding amount due for the same class of gas service with the Company and the Applicant is unwilling to make arrangements with the Company for payment; or

2. A condition exists which, in the Company's judgment, is unsafe or hazardous to the Applicant, the general population, or the Company's personnel or facilities; or

3. The Applicant refuses to provide the Company with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements; or

4. Customer is known to be in violation of the Company's Pricing Plans; or

5. Customer fails to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the Customer and which have been specified by the Company as a condition for providing service; or

6. Applicant falsifies his or her identity for the purpose of obtaining service.

D. Service Establishments, Re-establishment or Reconnection Charge

1. For the purpose of this Rule, the definition of service establishment is where the Customer's facilities are ready and acceptable to the Company, the Applicant has obtained all required permits and/or inspections indicating that the Applicant's facilities comply with local construction safety and governmental standards and regulations, and the Company needs only to install a meter, read a meter, or turn the service on.

2. The Company will charge for service establishment, re-establishment, or reconnection other than service transfers under usual operating procedures, during regular business hours as set forth in the Statement of Additional Charges.

~~2.~~3. Should service be established, re-established, or reconnected during a period after~~outside of~~ ~~other than~~ the Company's regular ~~working~~business hours, at the Customer's request, the Customer ~~may~~will be required to pay an after-hour charge for the service connection as set forth in the Statement of Additional Charges. Where the Company's scheduling will not permit service establishment on the same day as requested, the Customer can elect to pay the after-hour charge for establishment that day, or his service will be established on the next available business~~working~~ day. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having staff available; there is no guarantee that the Company will have the staffing available for service establishment, re-establishment or reconnection after business hours.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

4. For service re-establishments at the same location where the same Customer has ordered a service disconnect within the preceding twelve (12) month period, such returning Customer in addition to the service re-establishment charge, shall pay the sum of the applicable monthly Customer Charges that would have accrued had the Customer not ordered the disconnect.

5. For service reconnections when due to the behavior of the Customer (*i.e.*, nonpayment, failure to comply with the Company's Pricing Plans) it has been necessary for the Company to discontinue service utilizing other than usual operating procedures prior to reconnection of gas service each time the gas is disconnected, in addition to the service reconnection charge set forth in the Statement of Additional Charges, the Customer shall pay the sum of the applicable monthly Customer Charges that would have accrued had the Customer not been disconnected within the preceding twelve (12) month period.

6. The Company will charge for the establishment or re-establishment for service transfers only, as set forth in the Statement of Additional Charges.

7. When the Company has made more than one failed attempt to establish service due to the Customer's absence from home, facilities not being ready, or lack of access to the point of delivery, the Customer will be required to pay a multiple attempts to connect charge as set forth in the Statement of Additional Charges, in addition to the service establishment charge.

~~SECTION NO. 3~~
~~ESTABLISHMENT OF SERVICE~~
~~(continued)~~

E. Temporary Service

1. Applicants for temporary service may be required to pay to the Company, in advance of service establishment, the estimated cost of installing and removing the facilities necessary for furnishing the desired service.

2. Where the duration of service is to be less than one (1) month, the Applicant may also be required to advance a sum of money equal to the estimated bill for service.

3. Where the duration of service is to exceed one (1) month, the Applicant may also be required to meet the deposit requirements of the Company, as outlined in Subsection B.1 above.

4. If at any time during the term of the agreement for service the character of a temporary Customer's operations changes so that, in the opinion of the Company, the Customer is classified as permanent, the terms of the Company's main extension rules shall apply.

SECTION NO. 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS

~~1.~~A. Information for Residential Customers

1. The Company shall make available upon Customer request, no later than sixty (60) days from the date of request, a concise summary of the rate schedule applied for by such Customer. The summary shall include the following:

    a. Monthly minimum or Customer charge, identifying the amount of the charge and the specific amount of usage included in the minimum charge, where applicable;

    b. Rate blocks, where applicable; and

    c. Any adjustment factor(s) and method of calculation.

2. Upon application or upon request, the Applicant or the Customer shall elect the applicable Pricing Plan best suited to their requirements. The Company may assist in making such election, but shall not be held responsible for notifying the Customer of the most favorable Pricing Plan and shall not be required to refund the difference in charges under different Pricing Plans.

    However, new non-residential Customers whose projected consumption is near the threshold between "large" and "small" Pricing Plans, may elect the "small" rate, subject to refund, if their usage qualifies them as a "large" Customer. An existing non-residential Customer will be moved to the "large" rate, or once moved, back to the "small" rate, only if their consumption history or a clear permanent change in consumption makes it clear the Customer will meet the volume requirements of one Pricing Plan.

    A review may be initiated by either the Company or the Customer. Any change of Pricing Plan, if appropriate, will be effective with the first bill issued seven (7) days after the initiation of the review. No adjustment of past billings due to Pricing Plan selection will be made to either the Company or the Customer, except for a new Customer who qualifies for the "large" Pricing Plan based on twelve (12) months of usage as set forth in this Rule.

SECTION NO. 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS
(continued)

3. Upon Customer request, the Company shall make available to the Customer, a copy of the ACC's Rules and Regulations (Arizona Administrative Code, Title 14, Article 3 - Gas Utilities) concerning:

   a. Deposits;

   b. Termination of Service;

   c. Billing and Collection; and

   d. Complaint Handling.

4. The Company, upon Customer request, shall transmit a written statement of actual consumption by the Customer for each billing period during the prior twelve (12) months unless such data is not reasonably ascertainable.

5. The Company shall inform all new Customers of their rights to obtain the information specified above.

6. The Company shall notify each Customer of the following information, in writing, within ninety (90) days after the Customer first receives gas service at a particular location:

   a. The Company does not maintain the Customer's buried piping;

   b. If the Customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage;

   c. Buried gas piping should be periodically inspected for leaks, periodically inspected for corrosion if the piping is metallic, and repaired if any unsafe condition is discovered;

   d. When excavating near buried gas piping, the piping must be located in advance, and the excavation done by hand;

   e. Plumbing contractors and heating contractors may assist in locating, inspecting, and repairing the Customer's buried piping; and

   f. In order to reduce damage by outside forces, the Company is a member of the statewide one call system in all areas in which the Company has underground natural gas piping.

SECTION NO. 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS
(continued)

2.B. Information Required Due to Changes in Rates and Charges

1. The Company shall ~~transmit~~send ~~to~~ affected Customers a concise summary of any changes in the Company's rates and charges significantly impacting those Customers.

2. This information shall be ~~transmitted~~sent to the affected Customer(s) within sixty (60) days of the effective date of the change in the Company's rates and charges.

SECTION NO. 5
MASTER METERING

A. Mobile Home Parks – New Construction/Expansion

1. The Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion are individually metered by the Company. Main extensions and service line connections to serve such new construction or expansion shall be governed by the main extension and/or service line connection policies of these rules and regulations.

2. Permanent residential mobile home parks for the purpose of this rule shall mean mobile home parks where the average length of stay for an occupant is a minimum of six (6) months.

3. For the purpose of this rule, expansion means construction which has been started for additional permanent residential spaces after the effective date of this rule.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS

~~1.~~A. Priority and Timing of Service Establishments

1. After an Applicant has complied with the Company's application and deposit requirements and has been accepted for service by the Company, the Company shall schedule that Customer for service establishment.

2. Service establishment shall be scheduled for completion within five (5) ~~working~~ business days of the date the Customer has been accepted for service, except in those instances when the Customer requests service establishment beyond the five (5) ~~working~~ business day limitation.

3. When the Company has made arrangements to meet with a Customer for service establishment purposes and the Company or the Customer cannot make the appointment during the prearranged time, the Company shall reschedule the service establishment appointment to the satisfaction of both parties.

4. The Company shall schedule service establishment appointments within a maximum range of four (4) hours during normal ~~working~~ business hours, unless another time frame is mutually acceptable to the Company and the Customer.

5. Service establishments shall be made only by qualified service personnel of the Company or its authorized representatives.

6. For the purpose of this rule, service establishments can occur only when the Customer's facilities are ready and acceptable to the Company and the Company needs only to install, read the meter, or turn the service on.

7. ~~A fee for service establishment, reestablishment, or reconnection of service may be charged at a rate on file with and approved by the ACC.~~ Whenever ~~the~~an Applicant requests after-hours handling of his request, the Company shall charge ~~an additional~~ fee ~~as~~ set forth in the Statement of Additional Charges~~on file with and approved by the ACC~~ unless a special call out is required. If a special call out is required, the charge shall be for a minimum of one (1) hour at a rate set forth in the Statement of Additional Charges~~the Company's then prevailing after-hours rate~~ for the service work on the Customer's premises. Special handling of calls and the related charges shall be made only upon request of the Applicant. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having staff available; there is no guarantee that the Company will have the staffing available for service establishment, re-establishment or reconnection after regular business hours.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

2.B. Facilities

1. Customer Provided Facilities

   a. An Applicant for service shall be responsible for the safety and maintenance of all Customer piping from the Ppoint of Ddelivery to the point of consumption.

   b. Meters shall be installed in a location suitable to the Company where the meters will be safe from street traffic, readily and safely accessible for reading, testing and inspection, and where such activities will cause the least interference and inconvenience to the Customer. The Customer shall provide, without cost to the Company and at a suitable and easily accessible location, sufficient and proper space for the installation of meters.

   c. Where the meter or service line location on the Customer's premises is changed at the request of the Customer or due to alterations on the Customer's premises, the Customer shall provide, and have installed at his expense, all Customer piping necessary for relocating the meter and the Company may make a charge for moving the meter and/or service line.

   d. On all newly-constructed Customer piping at the meter interconnection, the Customer will be required to install necessary piping and equipment before the meter is installed.

2. Company Provided Facilities

   a. The Company will install, at its own expense, the meter set assembly ("MSA") at a suitable location near the side wall of the Customer's building approximately three (3) feet or more from that front corner of the building nearest to the street in which the Company's distribution main is located. However, the Company, at its option, has the right to locate the meter at any location meeting the criteria of Subsection B.1.b of this section.

      The three (3) feet as noted above refers to the approximate location of the meter from the corner of the building that is nearest to the street in which the distribution main servicing that Customer is located. The gas service riser, service cock, regulator and meter are all above ground. The service from the Company's distribution main to the building is below ground.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

b. The Company or authorized representative will install the gas service line and make all connections of the gas service line from the distribution main to the service riser. The Company will in all cases be responsible for the cost of construction of the service line from the Company's distribution main to the Customer's property line for an amount not to exceed the allowable investment as calculated by the Incremental Contribution Study (see Section No. 7, Subsection B), with the Customer reimbursing the Company for the difference. The Customer will reimburse the Company for the gas service line on the Customer's property at a rate of ~~sixteen~~ twenty-two dollars and fifty cents~~dollars~~ (~~$16.00~~$22.50) per foot. The Customer is responsible for ~~locating facilities on private property and~~ removal of landscaping prior to installation or be subject to applicable charges. For Customers who provide the trench for the service line on the Customer's property, Section No. 7, Subsection B.~~4~~5.d will apply and the Customer will reimburse the Company at a rate of ~~twelve~~ sixteen dollars and fifty cents (~~$12.00~~$16.50) per foot ~~for the excess footage~~. The Customer, at the Customer's own expense, shall furnish, install, and be responsible for all other pipe, fittings, connections, and appurtenances between the ~~P~~point of ~~D~~delivery and each point of consumption. The cost of installation, paid by the Applicant, shall be the average actual cost of installation, calculated and averaged annually by the Company.

c. No Customer-owned pipe shall be directly connected with the Company's distribution mains or services. No connection shall be made by the Customer between the facilities of the Company, including the meter, service cock and regulator and those of the Customer, nor shall any facilities of the Company be set, connected, disconnected, removed, repaired or altered except by the Company's representatives.

d. A single meter and a single ~~P~~point of ~~D~~delivery may be used to supply a group of buildings, such as those of a hospital or industrial establishment under single ownership or control. Such applications may fall under the Master Meter rule as defined in the Arizona Administrative Code.

e. The Company may decline service to mobile residences or portable or other temporary structures if the conditions do not afford adequate protection for the occupant(s) thereof, or the persons or property of others. In no event will gas service be permitted, if to the Company's knowledge, the Customer or the Customer's facilities fail to meet applicable requirements of law, of the State, or of any local code.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

3. Easements and Right-of-Way

Each Customer shall grant, at no cost to the Company, an adequate easement and right-of-way, satisfactory to the Company to ensure proper service connection. Failure on the part of the Customer to grant an adequate easement and right-of-way shall be grounds for the Company to refuse service.

4. Unauthorized work or facilities

When the Company discovers that a Customer or the Customer's Agent has performed work or has constructed facilities that has altered the installation of the Company's facilities to the point that work is necessary to restore the previously installed Company facilities to meet regulatory or Company requirements, the Company shall notify the Customer or the Customer's Agent and the Company shall take whatever actions are necessary to eliminate the hazard or violation at the Customer's expense.

5. Point of Delivery

The ~~P~~point of ~~D~~delivery for all gas delivered to any Customer shall be at the point of interconnection between the facilities of the Company and those of the Customer.

6. Excess Flow Valve Installation

In accordance with Title 49, Section 192.381 of the Code of Federal Regulations and requirements set forth in HR5782, the installation of an Excess Flow Valve ("EFV") shall be performed by the Company on each single family residence service line connected to its distribution system whether ~~if~~ the service line is installed or entirely replaced. ~~after June 1, 2008.~~

a. The Applicant shall provide the Company information concerning the gas usage and demand requirements. The EFV will be designed and constructed so that suitable gas capacity is available and satisfactory to the Company.

b. The Company will construct, own, operate, and maintain the EFV in connection with the service line installation.

c. Costs associated with the mandated installation of the EFV shall be paid by the Applicant as a nonrefundable Contribution in Aid of Construction ("CIAC").

   i. The cost of installation, paid by the Applicant, shall be the average actual cost of installation, calculated and averaged annually by the Company.

d. Where it is necessary to change or alter the EFV, due to a request or alteration of the Customer's premise by the Customer, the Customer shall reimburse the Company for all expenses in connection with upgrading or removing the EFV.

e. The Company shall pay for all costs associated with replacement or maintenance of the EFV in connection with a line replacement or maintenance project.

SECTION NO. 7
EXTENSION OF LINES

Extensions of gas distribution services and mains necessary to furnish permanent service to Applicants will be made in accordance with this rule.

A. General

The Company will construct, own, operate and maintain service line and distribution main extensions.

1. Gas service lines will be designed and installed so that suitable capacity from the Company's distribution main to a meter location on the property of the Applicant is satisfactory to the Company. If downstream usage changes or is altered by the Customer, the Customer may be responsible for costs to upgrade or enlarge the service line to accommodate additional capacity requirements.

2. Gas distribution main extensions will be only along public streets, roads, and highways, which the Company has legal right to occupy, and on public lands and private property across which rights-of-way, satisfactory to the Company, may be obtained.

3. All Company distribution mains and service lines shall be installed in accordance with all applicable Company standards.

B. Service and Main Extensions to Applicants for Service

General Policy – All service line and main line extension agreements are made on the basis of economic feasibility.

a.1. Facility Charge – If any Applicant fails to use natural gas for equipment stated in the application and used as the basis for estimating the allowable investment ~~(ICS)~~ within four (4) months of the completion of the main, the Company may bill the Applicant for the incremental cost allowed towards the extension of service. The Applicant shall pay within forty-five (45) days the charge as a non-refundable contribution towards the cost of extending service.

SECTION NO. 7
EXTENSION OF LINES
(continued)

~~b.~~2. At its option, the Company may require a performance bond or other surety guaranteeing bona fide operation of the facility for which the extension is requested, in accordance with Applicant's representation in the contract.

~~c.~~3. Master Meter Extensions – If the residential Customers are tenants in a fully improved master-metered mobile home park ("MMP") and the MMP is currently or was formerly served as a master-metered mobile home park, the allowable investment for the MMP will be calculated by the following Incremental Contribution Method and formula:

AI = (FR – CR) x 5

where: AI = Allowable Investment

FR = The MMP's estimated future total annual revenue, assuming conversion to individual residential service, using the MMP's average park occupancy for the past two (2) years, less the Company's current average cost of purchased gas.

CR = The MMP's current total annual revenue, under the applicable schedule, averaged for the past two (2) years, less the Company's current average cost of purchased gas. If the MMP is not a current Customer of the Company, the CR will be determined on the basis of engineering estimates of occupancy and usage.

The Company will install that portion of each service in excess of the allowed investment subject to a nonrefundable contribution to be paid by the Applicant MMP prior to construction. In no event shall costs above the allowable investment be borne by the Company.

~~d.~~4. Incremental Contribution Method – Gas service line and main line extensions will be made by the Company at its expense for an amount not to exceed the ~~A~~allowable ~~i~~investment as calculated by an Incremental Contribution Study ("ICS").

~~1.~~a. Allowable investment shall mean a determination by the Company that the revenues less the incremental gas cost to serve the Applicant provides a rate of return on the Company's investment no greater than the weighed average cost of capital authorized by the ACC in the Company's most recent general rate case.

~~2.~~b. If the ICS has an allowable investment that is more than the cost of the main extension, then the excess amount may be applied to reduce the cost of service line installation up to the Customer's property line, except that it shall not be used to reduce the cost of excess flow valve installation which shall be paid by the customer.

SECTION NO. 7
EXTENSION OF LINES
(continued)

~~3.~~c. The Company, after conducting an ICS, may at its option, extend its facilities to Customers whose usage does not satisfy the definition of economic feasibility, but who otherwise are permanent Customers, provided the Customer pays a nonrefundable ~~advance~~contribution, necessary to make the extension economically feasible.

~~4.~~d. Applicants may provide trenching for service lines and/or distribution mains to the Company's specifications and the Applicant's costs will be reduced accordingly.

~~5.~~e. Customers provided with line extensions using the ICS shall be reviewed annually for a period of five (5) years to determine the amount of any refund, as described in Subsection B.~~5~~6 below.

~~6.~~f. For the purposes of this rule, "economic feasibility" means that the estimated incremental revenues derived from serving the Applicant, less the incremental gas cost to serve the Applicant, meets the estimated costs of serving the Applicant, including meeting capital costs as determined by the weighed average cost of capital authorized by the ACC in the Company's most recent general rate case. An extension will not be considered economically feasible if the Applicant does not install a functioning water heater and furnace within four (4) months of the completion of the main.

~~e.~~5. Method of Refund

Amounts advanced by the Customer(s) in accordance with this rule, less any unpaid Facility Charges, shall be refunded, without interest, in the following manner:

~~A.~~a. Refunds of an advance shall be made for each additional separately metered permanent service connected to the main extension for which an advance was collected using an ICS that includes the additional Customer(s).

~~B.~~b. No refunds will be made for additional Customers connecting to a further extension or series of extensions constructed beyond the original extension.

~~C.~~c. The Customer may request an annual survey to determine if additional Customers have been connected to and are using service from the extension. In no case shall the amount of the refund exceed the amount originally advanced.

~~D.~~d. The refund period shall be five (5) years from the date of the completion of the extension. No refunds will be made by the Company after the termination of the refund period. Any portion of the advance that remains unrefunded at the end of the refund period shall be considered an unrefundable contribution.

~~E.~~e. Any assignment by a Customer of their interest in any part of an advance, which at the time remains unrefunded, must be made in writing and approved by the Company.

~~F.~~f. Amounts advanced under a gas main extension rule previously in effect will be refunded in accordance with the provisions of that rule.

SECTION NO. 7
EXTENSION OF LINES
(continued)

C. Service and Main Extensions to Service Individually Metered Subdivisions, Tracts, Housing Projects, Multi-Family Dwellings and Mobile Home Parks or Estates

1. Advances

a. Gas distribution service and main extensions to and within individually metered subdivisions, tracts, housing projects, multi-family dwellings and mobile home parks or estates will be constructed, owned and maintained by the Company in advance of applications for service by bona fide Customers only when the entire estimated cost of such extensions as determined by the Company, is advanced to the Company, and a main extension agreement is executed. This advance may include the cost of any gas facilities installed at the Company's expense in conjunction with a previous service or main extension in anticipation of the current extension.

b. The Company may require a subdivider, builder or developer to provide trenching for service lines and/or distribution mains and may also require the subdivider, builder or developer to provide bedding & shading material to Company specifications.

c. For developers who have entered into a main extension agreement and facilities have been installed and then they or some other party request subsequent reconfiguring of facilities or other changes requiring additional expenditures by the Company, these new costs will be entirely paid for with a non-refundable contribution and any refunds will be made in accordance with the original agreement. No additional agreement or extension of the time for refunds will be made to cover the area piped under the original extension agreement.

d. Upon completion of installation, the Company will perform a reconciliation of the estimate to actual costs incurred and may bill the Customer for any variance with the new amount included in the refundable balance, or at the Company's option withhold refunds until the underpayment is satisfied.

e. See Subsection B.3 above for requests to serve MMP through individual residential meters if the MMP is currently or was formerly served under an MMP schedule.

f. Refunds will be made to developers as described in Subsection B.5 above.

D. General Conditions

~~A.~~1. Postponement of Advance

The Company, at its option, may postpone, for a period not to exceed five (5) years that portion of an advance which it estimates would be refunded under the provisions of this rule. At the end of such refund period, the Company shall collect all such amounts not previously advanced. When advances are postponed, the Applicant may be required to furnish to the Company, a Company-approved surety, to assure payment of any postponed amounts throughout the term of the facilities extension agreement up until the end of the postponement period.

SECTION NO. 7
EXTENSION OF LINES
(continued)

B.2. The Applicants or developer will provide property location, tax identification numbers, lot numbers, street names and other property information helpful to planning an extension.

C.3. Contracts

1.a. Each Applicant requesting an extension in advance of applications for service will be required to execute a main extension agreement covering the terms under which the Company will install distribution mains in accordance with the provisions of the Company's Pricing Plans.

2.b. At the time service is requested, the Applicant will submit a list of natural gas equipment to be used including the BTU input.

D.4. One Service for a Single Premise

a. The Company will not install more than one service line to supply a single premise, unless it is for the convenience of the Company or an Applicant requests an additional service, and in the opinion of the Company, an unreasonable burden would be placed on the Applicant if the additional service were denied. When an additional service is installed at the Applicant's request, the Applicant shall make a nonrefundable contribution for the additional service based on the Company's estimated cost.

b. When a service extension is made to a meter location upon private property which is subsequently subdivided into separate premises, with the ownership portions thereof divested to other than the Applicant or the Customers, the Company shall have the right, upon written notice, to discontinue service without obligation or liability. Gas service, as required by the Applicant or Customer, will be reestablished in accordance with the applicable provisions of the Company's rules.

E.5. Branch Services

The Company, at its option, may install a branch service for units on adjoining premises.

SECTION NO. 7
EXTENSION OF LINES
(continued)

~~F.~~6. Main Extension Agreement Requirements

a. Upon request by an Applicant for a main extension, the Company shall prepare, without charge, a preliminary sketch and rough estimate of the cost of the installation to be advanced by the Applicant.

b. Any Applicant for a main extension requesting the Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with the Company an amount equal to the estimated cost of preparation. The Company shall, upon request, make available within ninety (90) days after receipt of the deposit referred to above, such plans, specifications, or cost estimates of the proposed main extension. Where the Applicant authorizes the Company to proceed with the construction of the extension, the deposit shall be credited to the cost of construction; otherwise, the deposit shall be nonrefundable. If the extension is to include oversizing of facilities to be done at the Company's expense, appropriate details shall be set forth in the plans, specifications and cost estimates. Subdividers providing the Company with approved subdivision plats shall be provided with plans, specifications or cost estimates within forty-five (45) days after receipt of the deposit referred to above.

c. The estimated cost of main extension and any resulting Main Extension Agreement is valid for ninety (90) days from the date of Company issue. Any signed agreement with appropriate payment where construction does not commence within ninety (90) days may be subject to review, recalculation and adjustment of advance requirements.

d. Where the Company requires an Applicant to advance funds for a main extension, the Company will ~~shall~~ furnish the Applicant, upon request, with a copy of this rule prior to the Applicant's acceptance of the Company's extension agreement.

SECTION NO. 7
EXTENSION OF LINES
(continued)

e. All main extension agreements requiring payment by the Applicant shall be in writing, signed by each party and shall include the following:

i. Name and address of Applicant(s);

ii. Proposed service address(es) or location(s);

iii. Description and sketch of the requested main extension;

iv. Description of requested service differentiated by Customer class;

v. Number of Customers served;

vi. Estimated cost to construct facilities;

vii. The Company's estimated start date and completion date for construction of the main extension;

viii. Each Applicant shall be provided a copy of the approved main extension agreements;

ix. Payment terms; and

x. A concise explanation of any refunding provisions, if applicable.

~~G.~~7. Relocation of Service Lines and Distribution Mains

a. When, in the judgment of the Company, the relocation of a distribution main or service line is necessary and is due either to maintenance of adequate service or the operating convenience of the Company, the Company shall perform such work at its own expense.

b. If relocation of a distribution main or service line is due solely to meet the convenience or the requirements of the Applicant or the Customer, such relocation, including metering and regulating facilities, shall be performed by the Company at the expense of the Applicant or the Customer.

c. Relocation of facilities will be mandatory and at the Customer's expense when actions of the Customer restrict the Company's access to or the safety of the facility.

SECTION NO. 7
EXTENSION OF LINES
(continued)

~~H.~~8. Standby Service or Residential Pool Heating

No allowance will be made for equipment used for standby or emergency purposes only or for equipment used for residential pool heating under Section No. 7, Subsection B.4.

~~I.~~9. Temporary Service

Extensions for temporary service or for operations, which in the opinion of the Company are of a speculative character or are of questionable permanency, will require an advance for the entire cost of the facilities needed, with provision for a refund using an ICS calculated annually, or at the termination of the temporary service.

~~J.~~10. Length and Location

The length of distribution mains or service lines required for an extension will be considered as the distance along the shortest practical and available route, as determined by the Company, from the Company's nearest permanent distribution main.

~~K.~~11. Service Impairment to Other Customers

When, in the judgment of the Company, providing service to an Applicant would impair service to other Customers, the cost of necessary reinforcement to eliminate such impairment may be included in the cost calculation for the extension.

~~L.~~12. Service From Transmission Lines

The Company will not tap a gas transmission main except when, in its sole opinion, conditions justify such a tap. Where such taps are made, the Applicant will pay the Company the cost of the tap, and extensions from the tap will be made in accordance with the provisions of this rule.

~~M.~~13. Other Types of Connections

Where an Applicant or Customer requests a type of service connection other than standard such as curb meters and vaults, etc., the Company will consider each such request and will grant such reasonable allowance as it may determine. The Company shall install only those facilities that it determines are necessary to provide standard natural gas service in accordance with the Company's Pricing Plans. Where the Applicant requests the Company to install special facilities which are in addition to, or in substitution for, or which result in higher costs than the standard facilities which the Company would normally install, the extra cost thereof shall be borne by the Applicant.

SECTION NO. 7
EXTENSION OF LINES
(continued)

~~N.~~14. Exceptional Cases

In unusual circumstances, when the application of this rule appears impractical or unjust to either party, the Company or the Applicant may refer the matter to the ACC for special ruling or for the approval of special conditions which may be mutually agreed upon, prior to commencing construction.

~~O.~~15. Taxes Associated with Nonrefundable Contributions and Advances

Any federal, state or local income taxes resulting from a nonrefundable contribution or advance by the Customer in compliance with this rule will be recorded as a deferred tax and appropriately reflected in the Company's rate base. However, if the estimated cost of facilities for any service line or distribution main extension exceeds $500,000, the Company may require the Applicant to include in the contribution or advance an amount (the "gross up amount") equal to the estimated federal, state or local income tax liability of the Company resulting from the contribution or advance, computed as follows:

$$\text{Gross Up Amount} = \frac{\text{Estimated Construction Cost}}{(1 - \text{Combined Federal-State-Local Income Tax Rate})}$$

After the Company's tax returns are completed, and actual tax liability is known, to the extent that the computed gross up amount exceeds the actual tax liability resulting from the contribution or advance, the Company shall refund to the Applicant an amount equal to such excess. When a gross-up amount is to be obtained in connection with an extension agreement, the contract will state the tax rate used to compute the gross up amount, and will also disclose the gross-up amount separately from the estimated cost of facilities. In subsequent years, as tax depreciation deductions are taken by the Company on its tax returns for the constructed assets with tax bases that have been grossed-up, a refund will be made to the Applicant in an amount equal to the related tax benefit. Such refunds will be in addition to any required refunds of actual construction costs required by the extension agreement. In lieu of scheduling such refunds over the remaining tax life of the constructed assets, a reduced lump sum refund may be made at the time when actual construction costs are refunded in full. This lump sum payment shall reflect the net present value of remaining tax depreciation deductions discounted at the Company's authorized rate of return.

SECTION NO. 8
PROVISION OF SERVICE

1.A. Company Responsibility

a.1. The Company shall be responsible for the safe transmission and distribution of gas until it passes the Ppoint of Ddelivery to the Customer.

b.2. The Company shall be responsible for maintaining in safe operating condition all meters, regulators, service pipe or other fixtures installed on the Customer's premises by the Company for the purpose of delivering gas to the Customer.

c.3. The Company may, at its option, refuse service until the Customer's pipes and appliances have been tested and found to be safe, free from leaks, and in good operating condition. Proof of such testing shall be in the form of a certificate executed by a licensed plumber or local inspector certifying that the Customer's facilities have been tested and are in safe operating condition.

d.4. The Company shall be required to test the Customer's piping for leaks when the gas is turned on. If such tests indicate leakage in the Customer's piping, the Company shall refuse to provide service until such time as the Customer has had the leakage corrected.

e.5. The Company shall be responsible for the operation and maintenance of all facilities up to the outlet of the meter installed by the Company or its authorized agent.

2.B. Customer Responsibility

1. Each Customer shall be responsible for maintaining in safe operating condition all Customer piping fixtures and appliances on the Customer's side of the Ppoint of Ddelivery.

2. Each Customer shall be responsible for safeguarding all Company property installed in or on the Customer's premises for the purpose of supplying gas service.

3. Each Customer shall exercise all reasonable care to prevent loss or damage to Company property, excluding ordinary wear and tear. The Customer shall be responsible for loss of or damage to, Company property on the Customer's premises arising from neglect, carelessness, or misuse and shall reimburse the Company for the cost of necessary repairs and replacements that arise from neglect, carelessness, or misuse.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

4. Each Customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering, tampering, or by-passing the Company's meters. This remedy is cumulative to any other remedy available to Company under law or ACC rules.

5. Each Customer shall be responsible for promptly notifying the Company of any gas leakage identified in the Customer's or the Company's equipment.

6. The Customer will be responsible for the loss of gas or damage caused by gas in piping beyond the Company's meter.

7. No rent or other charge whatsoever will be made by the Customer against the Company for placing or maintaining meters, regulators, service lines, fixtures, etc. upon the Customer's premises.

3.C. Continuity of Service

The Company shall make reasonable efforts to supply a satisfactory and continuous level of service.

4.D. Liability

1. The Company shall not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from the following:

   A.a. Any cause against which the Company could not have reasonably foreseen or made provision for;

   B.b. Intentional service interruptions to make repairs or perform routine maintenance; or

   C.c. Curtailment.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

2. Neither the Company nor the Customer shall be liable to the other for any act, omission or circumstances (including, with respect to the Company, but not limited to, inability to provide service) occasioned by or in consequence of flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements, or accident or explosion, or war, rebellion, civil disturbance, mobs, riot, blockade, terrorist actions, or other acts of the public enemy, or acts of God, or interference of civil and/or military authorities, or strikes, lockouts or other labor difficulties, or vandalism, sabotage or malicious mischief, or usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect, or breakage or accidents to equipment or facilities, or lack, limitation or loss of electrical or gas supply, or any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by the exercise of due diligence such party is unable to prevent or overcome; provided, however, that nothing contained herein shall excuse the Customer from the obligation of paying for gas delivered or services rendered.

3. A failure to settle or prevent any strike or controversy with employees or with anyone purporting or seeking to represent employees shall not be considered to be a matter within the control of the Company.

4. Company will not be responsible for any third-party claims against Company that arise from Customer's use of Company's gas.

5. Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any act or omission of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

6. The liability of the Company for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment shall not exceed an amount equal to the charges applicable under the Company's Pricing Plan (calculated on a proportionate basis where appropriate) to the period during which such error, mistake, omission, interruption or delay occurs.

7. In no event shall the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue or profits) of any kind whatsoever regardless of the cause or foreseeability thereof.

8. The Company shall not be responsible for any loss or damage occasion or caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any regulators, gas piping, appliances, fixtures or apparatus.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

~~5.~~E. Change in Character of Service

1. When a change is made by the Company in the type of service rendered which would adversely affect the efficiency of operation or require the adjustment of the equipment of Customers, all Customers who may be affected shall be notified by the Company at least thirty (30) days in advance of the change or, if such notice is not possible, as early as feasible. Where adjustments or replacements of the Company's standard equipment must be made to permit use under such changed condition, adjustments shall be made by the Company without charge to the Customers.

~~6.~~F. Service Interruptions

1. The Company shall make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

2. The Company shall make reasonable provisions to meet emergencies resulting from failure of service and shall issue instructions to its employees covering procedures to be followed in the event of emergencies in order to prevent or mitigate interruption or impairment of service.

3. In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

4. When the Company plans to interrupt service for more than four (4) hours to perform necessary repairs or maintenance, the Company shall attempt to inform affected Customers of the scheduled date and estimated duration of the service interruption at least twenty-four (24) hours in advance. Such repairs shall be completed in the shortest possible time to minimize the inconvenience to the Customers.

5. The ACC shall be notified of interruptions in service affecting the entire system or any major division of the entire system. The interruption of service and the cause shall be reported by telephone to the ACC within one (1) hour after the responsible representative of the Company becomes aware of said interruption, and shall be followed by a written report to the ACC.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

7.G. Heat Value Standard for Natural Gas

The Company shall supply gas to its Customers with an average total heating value of not less than nine hundred (900) BTUs per cubic foot. The number of BTUs per cubic foot actually delivered through the Customer's meter will vary according to the altitude and elevation of the location where the Customer is being provided service.

8.H. Standard Delivery Pressure

a.1. The Company shall maintain the Standard Delivery Pressure of at the outlet of the Customer's meter, subject to variation under load conditions.

b.2. In cases where a Customer desires service at greater than Standard Delivery Pressure, the Company may supply, at its option, such greater pressure if and only as long as the furnishing of gas to such Customer at higher than standard delivery pressure will not be detrimental to the service of other Customers of the Company. The Company reserves the right to lower the delivery pressure or discontinue the delivery of gas at higher pressure at any time upon reasonable notice to the Customer. Where service is provided at pressure higher than Standard Delivery Pressure, the meter volumes shall be corrected to that higher pressure.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

~~9.I.~~ Determination of Therms for Billing

1. Heating Value – The heating value (BTU per cubic foot) of the natural gas delivered will vary depending on the source of supplies received by the Company. The average heating values will be determined from the volumetric weighted average heating values of the supplies received by the Company.

2. Metered Volumes – The number of therms to be billed will be determined by multiplying the difference in meter readings by an appropriate billing factor.

   a. Therms are determined from the volumes measured by the following:

A		B		C
Atmospheric Pressure at Elevation + Delivery Pressure / 14.73 Atmospheric Pressure at Sea Level	x	Average Heating Value (BTU per cubic foot) / 100,000 BTU per Therm	x	Super Compressibility Factor

Where:
A = Correction for atmospheric pressure at elevation and applicable delivery pressure
B = Applicable heating value of natural gas received
C = Correction for super compressibility ratio

   b. Atmospheric Pressures at Elevations within the Company's service territory are outlined in the following table. At such time additional elevation bands are needed within the various areas served by the Company, new bands ~~geographical zones~~ will be added.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

Elevation Range	Atmospheric Pressure Base
201 - 400	14.57206
401 - 600	14.46665
601 - 800	14.36200
801 - 1000	14.25810
1001 - 1200	14.15495
1201 - 1400	14.05253
1401 - 1600	13.95084
1601 - 1800	13.84987
1801 - 2000	13.74962
2001 - 2200	13.65007
2201 - 2400	13.55122
2401 - 2600	13.45306
2601 - 2800	13.35558
2801 - 3000	13.25878
3001 - 3200	13.16265
3201 - 3400	13.06718
3401 - 3600	12.97237
3601 - 3800	12.87820
3801 - 4000	12.78468
4001 - 4200	12.69179
4201 - 4400	12.59954
4401 - 4600	12.50791
4601 - 4800	12.41689
4801 - 5000	12.32648
5001 - 5200	12.23668
5201 - 5400	12.14748
5401 - 5600	12.05887
5601 - 5800	11.97084
5801 - 6000	11.88340
6001 - 6200	11.79653
6201 - 6400	11.71023
6401 - 6600	11.62449
6601 - 6800	11.53932

6801 - 7000	11.45469
7001 - 7200	11.37061
7201 - 7400	11.28708
7401 - 7600	11.20408

~~Northern Arizona:~~

~~Geographical Zone Description~~	~~Atmospheric Pressure Base~~
~~ASHFORK AZ E4801-5000~~	~~12.3264800~~
~~ASHFORK AZ E5001-5200~~	~~12.2366800~~
~~BAGD CPR AZ E3601-3800~~	~~12.8782000~~
~~BAGD ML AZ E2601-2800~~	~~13.3555800~~
~~BAGDAD MINE E0401-0600~~	~~14.4666500~~
~~BLACK CANYON CITY AZ E1601-1800~~	~~13.8498700~~

~~SECTION NO. 8~~
~~PROVISION OF SERVICE~~
~~(continued)~~

~~Geographical Zone Description~~	~~Atmospheric Pressure Base~~
~~BLACK CANYON CITY AZ E1801-2000~~	~~13.7496200~~
~~CAMP VERDE AZ E2801-3000~~	~~13.2587800~~
~~CAMP VERDE AZ E3001-3200~~	~~13.1626500~~
~~CHINO VALLEY AZ E4201-4400~~	~~12.5995400~~
~~CHINO VALLEY AZ E4401-4600~~	~~12.5079100~~
~~CHINO VALLEY AZ E4601-4800~~	~~12.4168900~~
~~CLARKDALE AZ E3001-3200~~	~~13.1626500~~
~~CLARKDALE AZ E3201-3400~~	~~13.0671800~~
~~CLARKDALE AZ E3401-3600~~	~~12.9723700~~
~~CORNVILLE AZ E3001-3200~~	~~13.1626500~~
~~CORNVILLE AZ E3201-3400~~	~~13.0671800~~
~~COTTONWOOD AZ E3001-3200~~	~~13.1626500~~
~~COTTONWOOD AZ E3201-3400~~	~~13.0671800~~
~~COTTONWOOD AZ E3401-3600~~	~~12.9723700~~
~~COTTONWOOD AZ E3601-3800~~	~~12.8782000~~
~~DUVAL AZ E3201-3400~~	~~13.0671800~~
~~FLAGSTAFF AZ E6201-6400~~	~~11.7102300~~
~~FLAGSTAFF AZ E6401-6600~~	~~11.6244900~~
~~FLAGSTAFF AZ E6601-6800~~	~~11.5393200~~
~~FLAGSTAFF AZ E6801-7000~~	~~11.4546900~~
~~FLAGSTAFF AZ E7001-7200~~	~~11.3706100~~
~~FLAGSTAFF AZ E7201-7400~~	~~11.2870800~~
~~HOLBROOK AZ E4801-5000~~	~~12.3264800~~
~~HOLBROOK AZ E5001-5200~~	~~12.2366800~~
~~HUMBOLDT AZ E4201-4400~~	~~12.5995400~~
~~HUMBOLDT AZ E4401-4600~~	~~12.5079100~~
~~HUMBOLDT AZ E4601-4800~~	~~12.4168900~~
~~INDPK AZ E6201-6400~~	~~11.7102300~~
~~JEROME AZ E4201-4400~~	~~12.5995400~~
~~JEROME AZ E4401-4600~~	~~12.5079100~~
~~JEROME AZ E4601-4800~~	~~12.4168900~~
~~JEROME AZ E4801-5000~~	~~12.3264800~~
~~JEROME AZ E5001-5200~~	~~12.2366800~~
~~JOSEPH CITY AZ E4601-4800~~	~~12.4168900~~
~~JOSEPH CITY AZ E4801-5000~~	~~12.3264800~~
~~KINGMAN AZ E3001-3200~~	~~13.1626500~~

~~SECTION NO. 8~~
~~PROVISION OF SERVICE~~
~~(continued)~~

~~Geographical Zone Description~~	~~Atmospheric Pressure Base~~
~~KINGMAN AZ E3201-3400~~	~~13.0671800~~
~~KINGMAN AZ E3401-3600~~	~~12.9723700~~
~~KINGMAN AZ E3601-3800~~	~~12.8782000~~
~~KINGMAN AZ E3801-4000~~	~~12.7846800~~
~~LAKE HAVASU CITY AZ E0201-0400~~	~~14.5720600~~
~~LAKE HAVASU CITY AZ E0401-0600~~	~~14.4666500~~
~~LAKE HAVASU CITY AZ E0601-0800~~	~~14.3620000~~
~~LAKE HAVASU CITY AZ E0801-1000~~	~~14.2581000~~
~~LAKE HAVASU CITY AZ E1001-1200~~	~~14.1549500~~
~~LAKE HAVASU CITY AZ E1201-1400~~	~~14.0525300~~
~~LAKE HAVASU CITY AZ E1401-1600~~	~~13.9508400~~
~~MAYER AZ E4001-4200~~	~~12.6917900~~
~~MAYER AZ E4201-4400~~	~~12.5995400~~
~~MOUNTAIN VIEW AZ E6401-6600~~	~~11.6244900~~
~~NAVAJO ARMY DEPOT E5401-5600~~	~~12.0588700~~
~~PAULDEN AZ E4001-4200~~	~~12.6917900~~
~~PAULDEN AZ E4201-4400~~	~~12.5995400~~
~~PAULDEN AZ E4401-4600~~	~~12.5079100~~
~~PHX CMT AZ E3401-3600~~	~~12.9723700~~
~~PINETOP/LAKESIDE AZ E6201-6400~~	~~11.7102300~~
~~PINETOP/LAKESIDE AZ E6401-6600~~	~~11.6244900~~
~~PINETOP/LAKESIDE AZ E6601-6800~~	~~11.5393200~~
~~PINETOP/LAKESIDE AZ E6801-7000~~	~~11.4546900~~
~~PINETOP/LAKESIDE AZ E7001-7200~~	~~11.3706100~~
~~PRESCOTT VALLEY AZ E4201-4400~~	~~12.5995400~~
~~PRESCOTT VALLEY AZ E4401-4600~~	~~12.5079100~~
~~PRESCOTT VALLEY AZ E4601-4800~~	~~12.4168900~~
~~PRESCOTT VALLEY AZ E4801-5000~~	~~12.3264800~~
~~PRESCOTT VALLEY AZ E5001-5200~~	~~12.2366800~~
~~PRESCOTT AZ E4601-4800~~	~~12.4168900~~
~~PRESCOTT AZ E4801-5000~~	~~12.3264800~~
~~PRESCOTT AZ E5001-5200~~	~~12.2366800~~
~~PRESCOTT AZ E5201-5400~~	~~12.1474800~~
~~PRESCOTT AZ E5401-5600~~	~~12.0588700~~
~~PRESCOTT AZ E5601-5800~~	~~11.9708400~~
~~PRESCOTT AZ E5801-6000~~	~~11.8834000~~

~~SECTION NO. 8~~
~~PROVISION OF SERVICE~~
~~(continued)~~

~~Geographical Zone Description~~	~~Atmospheric Pressure Base~~
~~SEDONA AZ E3401-3600~~	~~12.9723700~~
~~SEDONA AZ E3601-3800~~	~~12.8782000~~
~~SEDONA AZ E3801-4000~~	~~12.7846800~~
~~SEDONA AZ E4001-4200~~	~~12.6917900~~
~~SEDONA AZ E4201-4400~~	~~12.5995400~~
~~SEDONA AZ E4401-4600~~	~~12.5079100~~
~~SEDONA AZ E4601-4800~~	~~12.4168900~~
~~SELIGMAN AZ E5001-5200~~	~~12.2366800~~
~~SHOW LOW AZ E5801-6000~~	~~11.8834000~~
~~SHOW LOW AZ E6001-6200~~	~~11.7965300~~
~~SHOW LOW AZ E6201-6400~~	~~11.7102300~~
~~SHOW LOW AZ E6401-6600~~	~~11.6244900~~
~~SNOWFLAKE AZ E5201-5400~~	~~12.1474800~~
~~SNOWFLAKE AZ E5401-5600~~	~~12.0588700~~
~~SPRING VALLEY AZ E3601-3800~~	~~12.8782000~~
~~SPRING VALLEY AZ E3801-4000~~	~~12.7846800~~
~~STONE CONTAINER E6001-6200~~	~~11.7965300~~
~~TAYLOR AZ E5401-5600~~	~~12.0588700~~
~~VERDE VALLEY AZ E3401-3600~~	~~12.9723700~~
~~VILLAGE OF OAK CREEK AZ E3601-3800~~	~~12.8782000~~
~~VILLAGE OF OAK CREEK AZ E3801-4000~~	~~12.7846800~~
~~VILLAGE OF OAK CREEK AZ E4001-4200~~	~~12.6917900~~
~~WILLIAMS AZ E6401-6600~~	~~11.6244900~~
~~WILLIAMS AZ E6601-6800~~	~~11.5393200~~
~~WILLIAMS AZ E6801-7000~~	~~11.4546900~~
~~WINSLOW AZ E4601-4800~~	~~12.4168900~~

~~SECTION NO. 8~~
~~PROVISION OF SERVICE~~
~~(continued)~~

~~Southern Arizona:~~

~~Geographical Zone Description~~	~~Atmospheric Pressure Base~~
~~AMADO AZ E2801-3000~~	~~13.2587800~~
~~AMADO AZ E3001-3200~~	~~13.1626500~~
~~NOGALES AZ E3201-3400~~	~~13.0671800~~
~~NOGALES AZ E3401-3600~~	~~12.9723700~~
~~NOGALES AZ E3601-3800~~	~~12.8782000~~
~~NOGALES AZ E3801-4000~~	~~12.7846800~~
~~PATAGONIA AZ E3601-3800~~	~~12.8782000~~
~~PATAGONIA AZ E3801-4000~~	~~12.7846800~~
~~PATAGONIA AZ E4001-4200~~	~~12.6917900~~
~~RIO RICO AZ E3001-3200~~	~~13.1626500~~
~~RIO RICO AZ E3201-3400~~	~~13.0671800~~
~~RIO RICO AZ E3401-3600~~	~~12.9723700~~
~~RIO RICO AZ E3601-3800~~	~~12.8782000~~
~~RIO RICO AZ E3801-4000~~	~~12.7846800~~
~~RIO RICO AZ E4001-4200~~	~~12.6917900~~
~~TUBAC AZ E2801-3000~~	~~13.2587800~~
~~TUBAC AZ E3001-3200~~	~~13.1626500~~
~~TUBAC AZ E3201-3400~~	~~13.0671800~~
~~TUBAC AZ E3401-3600~~	~~12.9723700~~

SECTION NO. 8
PROVISION OF SERVICE
(continued)

~~10.~~J. Construction Standards and Safety

The Company's pipelines and pipeline facilities for the transportation of gas within the State of Arizona shall conform with and be subject to the Federal Safety Standards as adopted by the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration. The Company maintains and updates an Operation and Maintenance plan and an Emergency plan. Upon discovery of occurrence, the Company will report all incidents as required under the Arizona Administrative Code, R14-5-203.

SECTION NO. 9
METER READING

1.A. Company or Customer Meter Reading

A.1. The Company may, at its discretion, allow for Customer reading of meters.

B.2. It shall be the responsibility of the Company to inform the Customer how to properly read the Customer's meter.

C.3. Where a Customer reads the meter, the Company will read the Customer's meter at least once every six (6) months.

D.4. The Company shall specify the timing requirements for the Customer to submit the monthly meter reading to conform to the Company's billing cycle.

E.5. In the event the Customer fails to submit the meter reading on time, the Company may issue the Customer an estimated bill.

F.6. Meters shall be read monthly on as close to the same day each month as practical.

2.B. Measuring of Service

1. All gas sold by the Company shall be metered, except in the case of gas sold according to a fixed charge schedule, or when otherwise authorized by the ACC.

2. When there is more than one (1) meter at a location, the metering equipment shall be so tagged or plainly marked as to indicate the facilities being metered.

3. If and when the Company installs multiple meters or service lines to serve a single Customer for the Company's convenience, meter readings may be combined for billing purposes.

3.C. Customer-Requested Meter Re-reads

a.1. At the request of a Customer, the Company will reread that Customer's meter within ten (10) working business days after such request by the Customer.

b.2. Any reread willmay be charged to the Customer at a rate set forth in the Statement of Additional Chargeson file and approved by the ACC, provided that the original reading was not in error.

c.3. When a reading is found to be in error, the re-read shall be at no charge to the Customer.

SECTION NO. 9
METER READING
(continued)

4.D. Access to Customer Premises

The Company shall have the right of safe ingress to and egress from the Customer's premises at all reasonable hours for any purpose reasonably connected with the furnishing of service and the exercise of any and all rights secured to the Company by law or the ACC's rules or the Company's Pricing Plans.

5.E. Customer-Requested Meter Tests

The Company shall test a meter upon Customer request and shall be authorized to charge the Customer for such meter test. The charge for the meter test is set forth in the Statement of Additional Charges. However, if the meter is found to be in error by more than three percent (3%), no fee will be charged to the Customer.

SECTION NO. 10
BILLING AND COLLECTION

~~a.~~A. Frequency and Estimated Bills

1. The Company shall bill monthly for services rendered. Meter readings shall be scheduled for periods of not less than twenty-five (25) days or more than thirty-five (35) days.

2. If the Company is unable to read a meter on the scheduled meter read date, the Company will estimate the consumption for the billing period, giving consideration to the following factors where applicable:

   a. The Customer's usage history in the previous twelve (12) months; and

   b. The amount of usage during the preceding month.

3. After the second consecutive month of estimating the Customer's bill for reasons other than severe weather, the Company will attempt to secure an accurate reading of the meter.

4. Failure on the part of the Customer to comply with a reasonable request by the Company for access to the Customer's meter may lead to the discontinuance of service.

5. Estimated bills will be issued only under the following conditions:

   ~~1.~~a. Failure of a Customer who reads his or her own meter to deliver the meter reading card to the Company in accordance with the requirements of the Company's billing cycle;

   ~~2.~~b. Severe weather conditions which prevent the Company from reading the meter; or

   ~~3.~~c. Circumstances that make it impossible to read the meter, such as locked gates, blocked meters, and vicious or dangerous animals, etc.

6. Each bill based on estimated usage will indicate that it is an estimated bill.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

~~b.~~B. Combining Meters - Minimum Bill Information

1. Each meter at a Customer's premises will be considered separately for billing purposes; and the readings of two (2) or more meters will not be combined unless approved by the Company.

2. Each bill for sales service will contain the following minimum information:

~~1.~~a. Date and meter reading at the start of billing period or number of days in the billing period;

~~2.~~b. Date and meter reading at the end of the billing period;

~~3.~~c. Billed usage;

~~4.~~d. Rate schedule number;

~~5.~~e. Company's telephone number;

~~6.~~f. Customer's name;

~~7.~~g. Service account number;

~~8.~~h. Amount due and due date;

~~9.~~i. Past due amount;

~~10.~~j. Adjustment factor, where applicable;

~~11.~~k. Taxes; and

~~12.~~l. The Arizona Corporation Commission's address.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

~~c.~~C. Billing Terms

~~a.~~1. All bills for gas service are due and payable no later than ten (10) days from the date the bill is rendered. Any payment not received within this time-frame shall be considered past due and may be subject to a late payment finance~~penalty~~ charge as set forth in the Statement of Additional Charges. If the tenth (10th) day falls on a weekend or holiday, then the past due date is extended to the next business day.

2. For purposes of this rule, the date the bill is rendered shall be the latest of the following:

   a. The postmark date;

   b. The mailing date; or

   c. The billing date shown on the bill (however, the billing date shall not differ from the postmark or mailing date by more than two (2) days.

3. All past due bills for gas service are due and payable within fifteen (15) days. Any payment not received within this time-frame shall be considered delinquent and will be issued a suspension of service notice. For Customers under the jurisdiction of a bankruptcy court, a more stringent payment or prepayment schedule may be required, if allowed by that court.

   a. The amount of the late payment penalty shall not exceed one and one-half percent (1.5%) of the delinquent bill, applied on a monthly basis.

4. All delinquent bills for which payment has not been received within five (5) days shall be subject to the provisions of the Company's suspension of service procedures.

5. All payments shall be made at or mailed to the office of the Company or to the Company's duly authorized representative.

6. A past due payment may be collected by a Company representative at the Customer's premises for a fee as set forth in the Statement of Additional Charges.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

~~d.~~D. Applicable Pricing Plans, Prepayments, Failure to Receive, Commencement Date

~~a.~~1. Each Customer shall be billed under the Pricing Plan indicated in the Customer's application for service.

~~b.~~2. The Company shall make provisions for advance payment for Company services.

~~c.~~3. Failure to receive bills or notices which have been properly placed in the United States mail shall not prevent such bills from becoming delinquent and does not relieve the Customer of the Customer's obligations therein.

~~d.~~4. Charges for service commence when the service is installed and connection made, whether used or not.

~~e.~~E. Meter Error Corrections

~~a.~~1. If, after testing, any meter is found to be more than three percent (3%) in error, either fast or slow, proper correction between three percent (3%) and the amount of the error shall be made on previous readings, and adjusted bills shall be rendered according to the following terms:

~~1.~~a. For the period of three (3) months immediately preceding the removal of such meter from service for testing or from the time the meter was in service since last tested, but not exceeding three (3) months since the meter shall have been shown to be in error by such test.

~~2.~~b. From the date the error occurred, if the date of the cause can be definitely fixed.

~~b.~~2. No adjustment shall be made by the Company except to the Customer last served by the meter tested.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

~~f.~~F. Nonsufficient Funds ("NSF") Checks and Denied Electronic Funds Transfers

~~A.~~1. The Company shall be allowed to recover a fee set forth in the Statement of Additional Charges~~ccording to the Company's Pricing Plans~~, for each instance where a Customer tenders payment for a Company service with an NSF check. This fee shall also apply when an electronic funds transfer ("EFT") is denied for any reason, including for lack of sufficient funds.

~~B.~~2. When the Company is notified by the Customer's bank that there are insufficient funds to cover the check tendered for service, or an EFT has been denied for any reason, the Company may require the Customer to make payment in cash, by money order or certified check, or by other means which guarantee the Customer's payment to the Company.

~~C.~~3. A Customer who tenders an NSF check or for whom an EFT is denied, shall in no way be relieved of the obligation to render payment to the Company under the original terms of the bill, nor defer the Company's provision for termination of service for nonpayment of bills.

4. No personal checks will be accepted if two (2) NSF checks have been received by the Company within a twelve (12) month period in payment of any billing.

~~g.~~G. Elevation/Pressure Adjustment

The Company shall adjust for pressure according to the procedures in Section 8.H of these Rules and Regulations.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

~~h.~~H. Deferred Payment Plan

1. The Company may, prior to termination of service, offer a deferred payment plan to qualifying residential Customers for the payment of unpaid bills for gas service.

2. Each deferred payment agreement entered into by the Company and the Customer, due to the Customer's inability to pay an outstanding bill in full, shall provide that service will not be discontinued if:

   a. The Customer agrees to pay a reasonable amount of the outstanding bill at the time the parties enter into the deferred payment agreement;

   b. The Customer agrees to pay all future bills for gas service in accordance with the Company's Pricing Plans; and

   c. The Customer agrees to pay a reasonable portion of the remaining outstanding balance in installments.

3. For the purposes of determining a reasonable installment payment schedule under these Rules, the Company and the Customer shall give consideration to the following conditions:

   ~~i.~~a. The size of the delinquent account;

   ~~ii.~~b. The Customer's ability to pay;

   ~~iii.~~c. The Customer's payment history;

   ~~iv.~~d. The length of time that the debt has been outstanding;

   ~~v.~~e. The circumstances which resulted in the debt being outstanding; and

   ~~vi.~~f. Any other relevant factors related to the circumstances of the Customer.

4. Any Customer who desires to enter into a deferred payment agreement shall establish such agreement prior to the Company's scheduled service termination date for nonpayment of bills. The Customer's failure to execute a deferred payment agreement prior to the scheduled service termination date shall not prevent the Company from terminating service for nonpayment.

5. Deferred payment agreements may be in writing and may be signed by the Customer and an authorized Company representative.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

6. A deferred payment agreement may include a finance charge of one and one-half percent (1.5%) per month.

7. If a Customer does not fulfill the terms of a deferred payment agreement, the Company shall have the right to disconnect service pursuant to the Company's termination of service rules (Section No. 11 of these Rules) and, under such circumstances, it shall not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

~~H.~~ Change of Occupancy

~~1.~~ 1. Not less than three (3) ~~working~~ business days advance notice must be given in person at the Company's office, in writing, or by telephone to discontinue service or to change occupancy.

~~2.~~ 2. The outgoing party shall be responsible for all Company services provided and/or consumed up to the scheduled turn-off date.

~~J.~~ Electronic Billing

Electronic Billing is an optional billing service whereby Customers may elect to receive, view, and pay their bills electronically. Electronic Billing includes the "UES e-bill" service and the "Sure No Hassle Automatic Payment ("SNAP") service. The Company may modify its electronic billing services from time to time. A Customer electing an electronic billing service may receive an electronic bill in lieu of a paper bill. Customers electing an electronic billing service may be required to complete additional forms and agreements. Electronic billing may be discontinued at any time by the Company or the Customer. An electronic bill will be considered rendered at the time it is electronically sent to the Customer. Failure to receive bills or notices which have been properly sent by an electronic billing system does not prevent such bills from becoming delinquent and does not relieve the Customer of the Customer's obligations therein. Any notices which Company is required to send to a Customer who has elected an electronic billing service may be sent by electronic means at the option of the Company. Except as otherwise provided in this subsection, all other provisions of the Company's Rules and Regulations and other applicable Pricing Plans are applicable to electronic billing.

SECTION NO. 11
TERMINATION OF SERVICE

~~1.~~A. Non-Permissible Reasons to Disconnect Service

~~a.~~1. The Company may not disconnect service for any of the reasons stated below:

~~1.~~a. Delinquency in payment for services rendered to a prior Customer at the premises where service is being provided, except in the instance where the prior Customer continues to reside on the premises.

~~2.~~b. Failure of the Customer to pay for services or equipment that are not regulated by the ACC.

~~3.~~c. Nonpayment of a bill related to another class of service.

~~4.~~d. Failure to pay a bill to correct a previous under-billing due to an inaccurate meter or meter failure, if the Customer agrees to pay over a reasonable period of time.

~~5.~~e. The Company may not terminate residential service where the Customer has an inability to pay and:

~~a.~~i. The Customer can establish through medical documentation that, in the opinion of a licensed medical physician, termination of service would be especially dangerous to the health of the Customer or to the health of a permanent resident residing on the Customer's premises;

~~b.~~ii. Life-supporting equipment is used in the home that is dependent on Company service for operation of such apparatus; or

~~c.~~iii. Where weather will be especially dangerous to health as defined herein or as determined by the ACC.

~~6.~~f. Residential service to persons who have an inability to pay and who have an illness, are ~~a senior citizen~~elderly, or who are handicapped will not be terminated until all of the following have been attempted:

~~1.~~i. The Customer has been informed of the availability of funds from various government and social assistance agencies; and

~~2.~~ii. A third party previously designated by the Customer has been notified and has not made arrangement to pay the outstanding Company bill.

A Customer utilizing the provisions of Subsection A.1.e or A.1.f above may be required to enter into a deferred payment agreement with the Company within ten (10) days after the scheduled service termination date.

~~7.~~g. Failure to pay the bill of another Customer as guarantor thereof.

~~8.~~h. Disputed bills where the Customer has complied with the ACC's rules on Customer bill disputes.

SECTION NO. 11
TERMINATION OF SERVICE
(continued)

~~2.~~B. Termination of Service Without Notice

~~a.~~1. The Company may disconnect service without advance written notice under the following conditions:

~~1.~~a. The existence of an obvious hazard to the safety or health of the Customer, the general population or which imperils service to other Customers;

~~2.~~b. The Company has evidence of tampering or fraud;

~~3.~~c. There is an unauthorized resale or use of gas services that is not in accordance with the ACC's rules and/or these Rules and Regulations or other Company Pricing Plans; or

~~4.~~d. The Customer has failed to comply with the curtailment procedures imposed by the Company in accordance with the Company's Pricing Plans.

~~b.~~2. The Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Company.

~~c.~~3. The Company shall maintain a record of all terminations of service without notice. This record shall be maintained for a minimum of one (1) year and shall be available for inspection by the ACC.

~~3.~~C. Termination of Service With Notice

1. The Company may disconnect service to any Customer for any reason stated below, provided that the Company has met the notice requirements described in Section 11.D below:

   a. Customer violation of any of the Company's Pricing Plans;
   b. Failure of the Customer to pay a delinquent bill for gas service;
   c. Failure of the Customer to meet agreed upon deferred payment arrangements;
   d. Failure to meet or maintain the Company's deposit requirements;
   e. Failure of the Customer to provide the Company reasonable access to its equipment and property;
   f. Customer breach of a written contract for service between the Company and Customer; or
   g. When necessary for the Company to comply with an order of any governmental agency having such jurisdiction.

2. The Company shall maintain a record of all terminations of service with notice. This record shall be maintained for one (1) year and shall be available for ACC inspection.

SECTION NO. 11
TERMINATION OF SERVICE
(continued)

4.D. Termination Notice Requirements

A.1. The Company may not terminate service to any of its Customers without providing advance written notice to the Customer of the Company's intent to disconnect service, except under those conditions specified where advance written notice is not required.

B.2. Such advance written notice shall contain, at a minimum the following information:

1.a. The name of the person whose service is to be terminated and the address where service is being rendered;

2.b. The Pricing Plan that was violated and explanation of the violation or the amount of the bill, which the Customer has failed to pay in accordance with the payment policy of the Company, if applicable;

3.c. The date on or after which service may be terminated; and

4.d. A statement advising the Customer that the Company's stated reason for the termination of services may be disputed by contacting the Company at a specific address or phone number, advising the Company of the dispute and making arrangements to discuss the cause for termination with a responsible employee of the Company in advance of the scheduled date of termination. The responsible employee shall be empowered to resolve the dispute and the Company shall retain the option to terminate service after affording this opportunity for a meeting, concluding that the reason of terminating is just, and advising the Customer of his right to file a complaint with the ACC.

C.3. Where applicable, a copy of the termination notice will be simultaneously forwarded to designated third parties.

5.E. Timing of Terminations With Notice

a.1. The Company shall be required to give at least five (5) days advance written notice prior to the termination date. For Customers under the jurisdiction of a bankruptcy court, a shorter notice may be provided, if permitted by that court.

b.2. Such notice shall be considered to be given to the Customer when a copy of the notice is left with the Customer or posted first class in the United States mail, and addressed to the Customer's last known address.

c.3. If, after the period of time allowed by the notice has elapsed, the delinquent account has not been paid nor arrangements made with the Company for the payment of the bill, or in the case of a violation of the Company's rules the Customer has not satisfied the Company that such violation has ceased, the Company may terminate service on or after the day specified in the notice without giving further notice.

SECTION NO. 11
TERMINATION OF SERVICE
(continued)

~~d.~~4. Service may only be disconnected in conjunction with a personal visit to the premises by an authorized representative of the Company.

~~e.~~5. The Company shall have the right, but not the obligation, to remove any or all of its property installed on the Customer's premises upon the termination of service.

~~6.~~F. Landlord/Tenant Rule

1. In situations where service is rendered at an address different from the mailing address of the bill or where the Company knows that a landlord/tenant relationship exists and that the landlord is the Customer of the Company, and where the landlord as Customer would otherwise be subject to disconnection of service, the Company may not disconnect service until the following actions have been taken:

   a. Where it is feasible to provide service, the Company, after providing notice as required in these rules, shall offer the occupant the opportunity to subscribe for service in the occupant's own name. If the occupant then declines to subscribe, the Company may disconnect service pursuant to the rules.

   b. The Company shall not attempt to recover payment of any outstanding bills or other charges due on the outstanding account of the landlord from a tenant. The Company shall not condition service to a tenant based on the payment of any outstanding bills or other charges due upon the outstanding account of the landlord.

SECTION NO. 12
ADMINISTRATIVE AND HEARING REQUIREMENTS

~~1.~~A. Customer Service Complaints

~~a.~~1. The Company shall make a full and prompt investigation of all service complaints made by its Customers, either directly to the Company or through the ACC.

~~b.~~2. The Company shall respond to the complainant and/or the ACC representative within five (5) ~~working~~ business days as to the status of the Company's investigation of the complaint.

~~c.~~3. The Company shall notify the complainant and/or the ACC representative of the final disposition of each complaint. Upon request of the complainant or the ACC representative, the Company shall report the findings of its investigation in writing.

~~d.~~4. The Company shall inform the Customer of the right of appeal to the ACC.

~~e.~~5. The Company shall keep a record of all written service complaints received and which shall contain, at a minimum, the following data:

~~1.~~a. Name and address of complainant;

~~2.~~b. Date and nature of complaint;

~~3.~~c. Disposition of the complaint; and

~~4.~~d. A copy of any correspondence between the Company, the Customer, and/or the ACC.

This record shall be maintained for a minimum period of one (1) year and shall be available for inspection by the ACC.

SECTION NO. 12
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

~~2.~~B. Customer Bill Disputes

1. Any Customer who disputes a portion of a bill rendered for gas service shall pay the undisputed portion of the bill prior to the delinquent date of the bill, and notify the Company's designated representative that any unpaid amount is in dispute.

2. Upon receipt of the Customer's notice of dispute, the Company shall:

   a. Notify the Customer within five (5) ~~working~~ business days of the receipt of a written dispute notice.

   b. Initiate a prompt investigation as to the source of the dispute.

   c. Withhold disconnection of service until the investigation is completed and the Customer is informed of the results. Upon request of the Customer, the Company shall report the results of the investigation in writing.

   d. Inform the Customer of the right of appeal to the ACC.

3. Once the Customer has received the results of the Company's investigation, the Customer shall submit payment within five (5) ~~working~~ business days to the Company for any disputed amounts. Failure to make full payment shall be grounds for termination of service.

~~3.~~C. ACC Resolution of Service and/or Bill Disputes

~~A.~~1. In the event a Customer and the Company cannot resolve a service and/or bill dispute, the Customer shall file a written statement with the ACC. By submitting such written notice to the ACC, the Customer shall be deemed to have filed an informal complaint against the Company.

~~B.~~2. Within thirty (30) days of the receipt of a written statement of Customer dissatisfaction related to a service or bill dispute, a designated representative of the ACC shall endeavor to resolve the dispute by correspondence and/or by telephone with the Company and the Customer. If resolution of the dispute is not achieved within twenty (20) days of the ACC representative's initial effort, the ACC shall hold an informal hearing to arbitrate the resolution of the dispute. The informal hearing shall be governed by the following rules:

   ~~A.~~a. Each party may be represented by legal counsel, if desired;

   ~~B.~~b. All such informal hearings may be recorded or held in the presence of a stenographer;

SECTION NO. 12
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

~~C.~~c. All parties will have the opportunity to present written or oral evidentiary material to support the positions of the individual parties; and

~~D.~~d. All parties and the ACC's representative shall be given an opportunity for cross-examination of the various parties.

The ACC's representative will render a written decision to all parties within five (5) ~~working~~ business days after the date of the informal hearing. Such written decision of the ACC's representative is not binding on any of the parties and the parties will still have the right to make a formal complaint to the ACC.

~~C.~~3. The Company may implement normal termination procedures if the Customer fails to pay all bills rendered during the resolution of the dispute by the ACC.

~~D.~~4. The Company shall maintain a record of written statements of dissatisfaction and their resolution for a minimum of one (1) year and make such records available for ACC inspection.

~~4.~~D. Notice by Company of Responsible Officer or Agent

1. The Company shall file with the ACC a written statement containing the name, business address and telephone numbers (office and mobile) of at least one officer, agent or employee responsible for the general management of its operations as a Company in Arizona.

2. The Company shall give notice, by filing a written statement with the ACC, of any change in the information required herein within five (5) days from the date of any such change.

SECTION NO. 13
BUDGET BILLING PAYMENT PLAN

A. The Company may, at its option, offer its Customers ~~Residential Customers may elect to participate in the Company's~~ Budget Billing Payment Plan ("Plan") for payment of charges for gas service.

B. ~~Upon Customer request, t~~The Company will develop, upon Customer request, an estimate of the Customer's levelized billing for a twelve (12) month period based on:

1. The Customer's actual consumption history at the service location, which may be adjusted for weather or other known variations. If sufficient history is not available, then an estimate will be prepared based on other similar service locations and Customer's anticipated load requirements; and

2. The applicable Pricing Plan, the estimated gas costs for the Plan year, and applicable taxes.

C. The Company shall provide the Customer with a concise explanation of how the levelized billing estimate was developed, the impact of levelized billing on a Customer's monthly bill, and the Company's right to adjust the Customer's billing for any variation between the Company's estimated billing and actual billing.

D. The Plan's monthly payment shall be determined as follows: Settlement month will be the Customer's anniversary date, twelve (12) months from the time the Customer is set up on the Budget Billing Payment Plan. The Company reserves the right to adjust the remaining monthly Plan semi-annually to reduce the likelihood of an excessive debt or credit balance in rates due to dramatic PGA increases or PGA surcharges.

~~a.~~1. The Company reserves the right to adjust the remaining monthly Plan payments of any Customer at any time if the Company's estimate of the Customer's usage and/or cost varies significantly from the Customer's actual usage and/or cost. Such review may also be initiated by the Customer. Any change resulting from such a review will be effective on a subsequent bill and no further notice is required.

~~b.~~2. The Customer shall continue to pay the monthly Plan payment amount each month, notwithstanding the current gas service charge shown on the bill.

~~c.~~3. Any other charges incurred by the Customer shall be paid monthly when due in addition to the monthly Plan payment.

~~d.~~4. Interest will not be charged to the Customer on accrued debit balances nor paid by the Company on accrued credit balances.

~~e.~~5. Any amount due the Company will be settled and paid at the time a Customer, for any reason, ceases to be a participant in the Plan. If an amount due to the Customer exceeds fifty dollars ($50.00), the Customer has the option to receive a bill credit or a refund; otherwise the credit will remain as a bill credit.

SECTION NO. 13
BUDGET BILLING PAYMENT PLAN
(continued)

~~f.~~6. Any Customer's participation in the Plan may be discontinued by the Company if the monthly Plan payment has not been paid on or before the billing date of the next monthly Plan payment.

~~g.~~7. If a Customer in the Plan shall cease, for any reason, to participate in the Plan, then the Company may refuse that Customer's re-entry in the Plan ~~until the following August or~~ for six (6) months~~, whichever is longer~~.

~~h.~~8. For those Customers being billed under the Plan, the Company shall show, at a minimum, the following information on the Customer's monthly bill:

~~1.~~a. *Actual consumption;*

~~2.~~b. Amount due for actual consumption;

~~3.~~c. Levelized billing amount due; and

~~4.~~d. Accumulated variation in actual versus levelized billing amount.

SECTION NO. 14
CURTAILMENT PLAN

A. The Company shall use reasonable diligence in its operations to render continuous service to all its Customers other than those Customers served under Pricing Plans expressly permitting interruptions of service for peak shaving purposes. If for any reason, however, the Company is unable to supply the demand for gas in any one or more of its systems, interruptions or curtailments of service shall be made in accordance with the provisions of this section. The Company shall not be liable for damages because of the operation of this section.

B. Applicability

1. The order of curtailment shall be in inverse order of the curtailment priorities set forth in Subsection C below.

2. Curtailment priorities shall apply to both sales and transportation Customers.

3. Customers being served under a discounted transportation or sales rate schedule shall be curtailed first. Customers paying the least will be curtailed first within an affected priority.

4. Each priority shall be curtailed in full before the next priority in order is curtailed.

5. When Priority 1 Customers would be curtailed due to system supply failure (either upstream capacity or supply failure), the Company is authorized to "preempt" deliveries of lower priority transportation Customers' gas and divert such supplies to the otherwise affected Priority 1 Customers. Affected transportation Customers will be curtailed to the same extent as sales Customers of the same priority. Such transportation Customers will be compensated for the preemption of their gas supply by either crediting the Customer's account with a like quantity of gas for use on a subsequent gas day, or by providing a cash payment or credit to the Customer's bill at the cost of gas per unit paid by the Customer. If the gas supply of an alternate fuel-capable transportation Customer is preempted according to this provision, the Company shall provide additional compensation to such Customer for the incremental cost of using the alternate fuel, (the difference between the actual cost of using the alternate fuel and the actual cost of gas paid by the Customer for the preempted gas). Such credit shall be applied to the Company's next scheduled billing after the Customer has furnished adequate proof to the Company concerning alternate fuel costs, replacement volumes, and gas costs.

6. The installation of a cogeneration facility shall not affect the underlying end-use priority of the establishment.

7. Natural gas utilized as compressed natural gas for vehicle fuel shall be classified as a commercial end-use.

SECTION NO. 14
CURTAILMENT PLAN
(continued)

~~9.~~8. Application of curtailment priorities will normally be done on a scheduled basis as part of the daily gas requirement nomination and confirmation routine. Operational emergency curtailment will conform to these priorities to the extent possible and practical.

~~10.~~9. A transportation Customer may be curtailed to the level of actual supply scheduled for that Customer, regardless of end-use priority.

C. Priorities

Priority 1: Residential, small commercial (less than five hundred (500) therms on a peak day), schools, hospitals, police protection, fire protection, sanitation facility, correctional facility, and emergency situation uses.

Priority 2A: Essential agricultural uses as certified by the Secretary of Agriculture.

Priority 2B: Essential industrial process and feedstock uses.

Priority 2C: Large Commercial (five hundred (500) therms or more on a peak day) and storage injection requirements, industrial requirements for plant protection, feedstock, process, ignition and flame stabilization needs not specified in Priority 2B.

Priority 3A: Industrial requirements not specified in Priorities 2, 4, and 5, of less than one thousand (1,000) therms on a peak day.

Priority 3B: All industrial requirements not specified in Priorities 2, 3A, 4, and 5.

Priority 4: Industrial requirements for boiler fuel use at less than thirty thousand (30,000) therms per peak day, but more than fifteen thousand (15,000) therms per peak day, where alternate fuel capabilities can meet such requirements.

Priority 5: Industrial requirements for large volume (thirty thousand (30,000) therms per peak day or more) boiler fuel use where alternate fuel capabilities can meet such requirements.

D. In the event of isolated incidents in order to avoid hazards and protect the public, the Company may temporarily interrupt service to certain Customers without regard to priority or any other Customer classification.

SECTION NO. 14
CURTAILMENT PLAN
(continued)

E. Definitions

1. "Alternate Fuel Capability" – A situation where an alternate fuel can be utilized whether or not the facilities for such use have actually been installed.

2. "Correctional Facility Uses" – A facility, the primary function of which is to house, confine, or otherwise limit the activities of a person who has been assigned to such facilities as punishment by a court of law.

3. "Essential Agricultural Use" – Any use of natural gas which is certified by the Secretary of Agriculture as an "essential agricultural use."

4. "Essential Industrial Process and Feedstock Uses" – Any use of natural gas by an industrial Customer as process gas, or as a feedstock, or gas used for human comfort to protect health and hygiene in an industrial installation.

5. "Feedstock Gas" – Natural gas use for which alternate fuels are not technically feasible, such as in applications requiring precise temperature controls and precise flame characteristics. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

6. "Fire Protection Uses" – Natural gas used by and for the benefit of fire fighting agencies in the performance of their duties.

7. "Flame Stabilization Gas" – Natural gas which is burned by igniters, main gas burners, or warm-up burners for the purpose of maintaining stable combustion of an alternate fuel.

8. "Hospital" – A facility, the primary function of which is delivering medical care to patients who remain at the facility (facility includes nursing and convalescent homes). Outpatient clinics or doctors' offices are not included in this definition.

9. "Ignition Gas" – Natural gas supplied to gas igniters in boilers to light main burners, whether the main burners are operated by gas, oil, or coal.

10. "Industrial Boiler Fuel" – Natural gas used in a boiler as a fuel for the generation of steam or electricity.

11. "Industrial Use" – Natural gas used primarily in a process which creates or changes raw or unfinished materials into another form or product, including electric power generation.

12. "Peak Day" – Maximum daily Customer use as determined by the best practical method available.

SECTION NO. 14
CURTAILMENT PLAN
(continued)

13. "Plant Protection Gas" – Minimum natural gas volumes required to prevent physical harm to the plant facilities or danger to plant personnel when such protection cannot be afforded through the use of an alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not include deliveries required to maintain plant production. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

14. "Police Protection Uses" – Natural gas used by law enforcement agencies in the performance of their duties.

15. "Process Gas" – Natural gas use for which alternate fuels are not technically feasible, such as in applications requiring precise temperature controls and precise flame characteristics. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

16. "Sanitation Facility Uses" – Natural gas use in a facility where natural gas is used to a) dispose of refuse, or b) protect and maintain the general sanitation requirements of the community at large.

17. "School" – A facility, the primary function of which is to provide instruction to regularly enrolled students in attendance at such facility. Facilities used for both educational and non-educational activities are not included under this definition unless the latter activities are merely incidental to the provision of instruction.

18. "Small Commercial Establishment" – Any establishment (including institutions and local, state, and federal government agencies) engaged primarily in the sale of goods or services where natural gas is used:

    a. in amounts of less than fifty (50) MCF on a peak day; and

    b. for purposes other than those involving manufacturing or electric power generation.

19. "Storage Injection Gas" – Natural gas injected by a distributor into storage for later use.

SECTION NO. 15
RATES AND UNIT MEASUREMENT

| ~~2.~~A. The rates and charges for gas service shall be those of the Company legally in effect and on file with the ACC.

| ~~3.~~B. All rates set forth in the Company's Pricing Plans are stated in therms. Unless otherwise provided by special contract, the number of therms delivered to any Customer shall be determined by measuring the volume of gas passing through that Customer's meter during the month to the nearest one hundred (100) cubic feet and applying the procedures of Section 8.H of these Rules and Regulations.

| ~~4.~~C. The unit of volume for measurement of gas sold shall be one (1) Cubic Foot of gas, as defined in Section 2, Subsection A.13 of these Rules and Regulations. The volume of gas measured shall be rounded to the nearest one hundred (100) cubic feet for any given period.

| ~~5.~~D. The atmospheric pressure will be the standard atmospheric pressure for the location.

| ~~6.~~E. The standard serving pressure shall be seven (7) inches of water pressure (four (4) ounces per square inch gauge) above the atmospheric pressure.

| ~~7.~~F. The standard temperature of sixty (60) degrees Fahrenheit will be used for volume determination unless stated otherwise under special contract. The Company shall retain the right, but shall not be obligated, to install temperature recording or compensating equipment as part of the measuring facilities. When such temperature recording equipment is used, the arithmetic average temperature of the gas each day, during periods of flow only, shall be used in computing the quantity of gas delivered by that day.

| ~~8.~~G. The Company, at its own option, may elect to serve a Customer at a pressure higher than the standard serving pressure. The Company shall correct such volume to Standard Conditions by the use of compensating equipment or the use of a factor. The Company retains the right to determine the method used for applying such correction. The factor used to correct the measured volume shall be in accordance with American Gas Association Report 3.

| ~~9.~~H. The therm conversion factor shall be determined each month and shall be the product of the conversion factor and the most recent heating value content available using the weighted average delivered pressure by office. The weighted average delivered pressure is derived monthly using the delivered pressure for each town code served which is reflective of each town code's elevation, weighted by the sales distribution among assigned gas distribution systems within each respective office. Further explained in Section 8.H. of these Rules and Regulations.

SECTION NO. 16
GAS METER TESTING AND MAINTENANCE PLAN

A. General Plan

The Company will annually sample groups of meters to determine the continuing accuracy and performance of the group. Certain safe and proper standards are defined, and meters will remain in service as long as they meet these standards. This program will allow the Company to obtain all the useful service available from a meter until the meter no longer meets prescribed standards. At that time, then it is proper for the meter to be removed, tested, repaired, or retired.

This procedure is for the purpose of testing and controlling the performance of small gas meters that are two hundred fifty (250) CFH or less. The program will identify and remove meters that do not meet the standards of performance described in Subsection D below, and identify and retain in service meters that do meet or exceed the stated standards. Meters are classified into groups, samples of each group are tested annually, and groups are removed from service when they do not meet performance standards.

B. Meter Groups

~~A.~~1. Meters are segregated into groups on the following basis:

a. Year last repaired or purchased;

b. Manufacturer;

c. Diaphragm type (leather or synthetic), when available; and

d. Geographic district.

~~B.~~2. For meters repaired or purchased in a given year, the groups are established at the beginning of the next year. When a new group being established is found to contain less than one thousand (1,000) meters, this group may be combined with another group having meters of the same or similar operating characteristics. An existing group may be divided into two or more groups, if experience characteristics of part of the group are sufficiently different from the remainder of the group to warrant separate sampling of the parts.

C. Sampling

A representative random sample is selected from each group of meters. The samples are used in determining the performance of each group of meters each year. If the initial order for meter removals does not produce an adequate sample, additional meters are drawn on a random basis. These meters are combined with the original sample for determining acceptability of the group. Samples are taken annually from all groups that have been in service for ten years or longer.

SECTION NO. 16
GAS METER TESTING AND MAINTENANCE PLAN
(continued)

D. Performance Standard

The criteria for acceptability for a group to remain in service are:

~~a.~~1. No more than ten percent (10%) of the meters tested in the group are more than three percent (3%) fast.

~~b.~~2. At least eighty percent (80%) of the meters tested in the group are within +/- three percent (3%) of zero error. This results in a condition wherein a minimum of ninety percent (90%) of the meters remaining in service are either within +/- three percent (3%) or are more than three percent (3%) slow and in the Customer's favor.

E. Records

The test results for each group are kept in appropriate records that indicate the number of meters in the sample versus the test results, expressed as a percent.

F. Removal of Groups

1. A test result falling on or above the prescribed standards is satisfactory and the groups will remain in service.
2. A test falling below the prescribed standards is not satisfactory and the group will be removed from service.
3. The Company, for its convenience, may remove a group (or part of a group) even though the group meets the requirements for remaining in service.

SECTION NO. 16
GAS METER TESTING AND MAINTENANCE PLAN
(continued)

G. Annual Reports

A report of the meter performance control program will be filed annually with the ACC, which will contain the following:

1. A description of each group, showing its identification, size and composition;

2. A list of the total number of meters tested, at Company initiative or upon Customer request;

3. A detailed list of the performance results of each group, showing the number of meters in the group, the number of meters removed during the year, the number of meters not tested (dead, non-registering, damaged, etc.), the number or meters tested, the number of meters slow - minus three percent (-3%), the number of meters accurate, the percent of meters accurate, the number of meters fast - plus three percent (+3%), and the percent of meters fast;

4. A summary of results for each year of service; and

5. A summary or the overall results.

SECTION 17
STATEMENT OF ADDITIONAL CHARGES

A.	Trip Charge:	
	1. Service Transfer	$20.00
	2. Collection Fee	$20.00
	3. Customer-Requested Meter Reread	$20.00
	4. Multiple Attempts to Connect	$20.00
B.	Service Establishment, Re-establishment, or Reconnection	
	During Regular Business Hours	$35.00
	After Regular Business Hours (same day request scheduled)	$50.00
C.	Special Call Out (Minimum one (1) hour)	
	Per hour	$70.00
D.	Customer-Requested Meter Test	$90.00
E.	NSF Check	$10.00
F.	Late Payment Finance Charge	1.5%
G.	Interest on Customer Deposits	One-year Treasury Constant Maturities rate

Regular Business Hours are defined as non-holiday weekdays from 8:30 a.m. to 4:30 p.m.

EXHIBIT

GAS-2

ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

RECEIVED

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AZ CORP COMMISSION
DOCKET CONTROL

Arizona Corporation Commission
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GARY PIERCE

IN THE MATTER OF HOOK-UP FEES FOR ELECTRIC AND NATURAL GAS UTILITIES.	DOCKET NO. E-00000K-07-0052 DOCKET NO. G-00000E-07-0052

COMMENTS

Tucson Electric Power Company ("TEP"), UNS Gas, Inc., ("UNS Gas") and UNS Electric, Inc. ("UNS Electric"), collectively the "Companies", through undersigned counsel, hereby submit their comments regarding Hook-Up Fees, as requested during the Arizona Corporation Commission's ("Commission") workshop on October 18, 2007.

I. INTRODUCTION.

At the conclusion of the Hook-Up Fees workshop interested parties were asked to provide written comments by November 1, 2007 regarding various issues that were raised and questions that were posed.

As a general principle, the Companies believe that the purposes of proposed Hook-Up Fees, namely to have growth pay substantially for all of its costs, could be accomplished by using well crafted line extension policies coupled with rates that are based on relevant costs of service. The Companies, in response to Commissioners' statements, are also looking into other ways that growth may fund growth including Hook-Up Fees.

TEP, UNS Electric and UNS Gas, are each separate entities with different growth experiences. Each company has an existing Line Extension Policy. The Companies will continue to refine their respective policies, update the embedded cost to serve in existing rates, and consider Hook-Up Fees in an effort to equitably treat new customers as they join the service territories of each utility.

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II. COMMISSION QUESTIONS.

1. How do we pay for growth?

- Rates?
- Hook-Up Fees?
- Other?

Response:

The Companies believe that growth should be evaluated on an individual customer and project basis. It is appropriate to have policies in place to assure that such growth, based on the rates in effect at the time of the project, will fairly contribute toward the recovery of the cost to serve that growth over the life of the service assets and provide for recovery of an equitable portion of distribution system costs. Essentially, to the extent that rates currently in effect to recover the average cost to serve existing customers is not adequate to recover the cost to serve new customers, we must seek to determine the nature of the unrecovered or under-recovered costs and functions of the associated facilities. Specifically, we must ask whether new facilities or expenditure necessitated by growth serve most or all customers on the system (e.g., on a vertically integrated system, new generation needed for growing load), just a few "new" customers in question (e.g., a pad mounted transformer serving a few larger homes in an outlying development), or some intermediate subgroup of customers (e.g., a substation serving customers in the Rancho Vistosa subdivision of Tucson). Generally, as one moves down the system, facilities serve smaller groups of customers.

One can argue that additional expenditure supporting facilities serving all customers – such as the new generation for a vertically integrated system – should not be recovered disproportionately from new customers through Hook-Up Fees. Traditionally, all customers within a class pay the same prices, and there is no penalty for being a "new" customer. An existing customer, after all, could choose to leave the system instead, thus

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freeing up resources and deferring the generation addition. Prospective incremental costs can be reduced either when a potential new customer chooses not to move in, or when an existing customer chooses to leave. The existing customer has no property right entitling him to preferential treatment in the allocation of costs based on when he connected to the system.

Recovery of generation costs through Hook-Up Fees may also be problematic if direct access becomes viable. Competitive Energy Service Providers ("ESPs") will have no reason to distinguish old from new customers. Direct access could lead to a reduction or complete waiver of generation related Hook-Up Fees by ESPs driven to aggressively compete for load. Moreover, any governmental attempt to impose some type of "new customer" / "old customer" differential interferes with the functioning of competitive markets – and extracting the benefits from viable competitive markets is, and should be, the driving force and motivation behind direct access.

Neither generation nor transmission should be recovered from Hook-Up Fees directed at new customers. Generation recovery through Hook-Up Fees is inappropriate for the aforementioned reasons. The use of Hook-Up Fees for transmission recovery is inappropriate because transmission is regulated by the Federal Energy Regulatory Commission ("FERC").

At the other extreme from generation and transmission are those costs associated with facilities serving just a small number of customers, typically contiguous customers. These costs typically are distribution or customer- related costs. Traditionally these costs have been collected through system-wide rates, where all customers in a class pay the same rate, or under the approved line extension guidelines providing for Contributions in Aid of Construction or Advances in Aid of Construction. The Companies believe that this process

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has worked well in the past, and can continue to provide the framework for cost recovery from new customers. A continuation of this framework is the Companies' preferred method for cases of typical Arizona growth (i.e., assuming that a utility's financial integrity is not threatened by extraordinary growth and/or significant regulatory lag). The Companies appreciate the Commission's concern, and request that any Hook-Up Fee program will allow for case-by-case variation in the load characteristics of new customers and the impact of customers on system operation and design. The policy should be designed to assure that new customers pay toward their service or project to assure existing customers will not unfairly subsidize new service. Clearly, this will be difficult to implement because there will be differences in opinions on how costs should be allocated among customers. When joint costs must be divided, there is often no unique optimal solution in economic theory. Consequently, parties are likely to differ on what constitutes a fair solution.

Finally, it is important that the Commission consider an economic concept at the theoretical heart of the Hook-Up Fee issue: externalities. Externalities arise when parties to an agreement fail to consider costs or benefits attributable to the agreement that affect third parties. Negative externalities arise when the third party experiences more costs than benefits as a result of the agreement.

In the context of Hook-Up Fees, the Commission is asking whether a utility's connection of a new customer imposes a negative externality on existing customers, with respect to the cost of utility service. If one is willing to move away from the tradition of system-wide average rates, one may propose a Hook-Up Fee in an effort to hold existing customers harmless from utility increases attributable to the new customer addition. Economic theory suggests that some or all of the Hook-Up Fee may be passed on to the new customers (depending on the elasticity of supply and elasticity of demand for new homes). As a result

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of the higher costs of new homes, the net benefit of relocating to this service territory is reduced and fewer people will move to affected new homes in the Hook-Up Fee territory. This may impose a disproportionate burden on lower income consumers new to the service territory, since the Hook-Up Fee is regressive (i.e., it imposes a higher percentage burden on lower income customers). Were the utility-related distribution/customer service-related negative externality the only externality, one might have a basis to argue that an appropriately set fee would result in a movement toward a socially optimal solution.

However, another economic concept most likely will trump the utility-related negative externality: the multiplier effect. When new people move to an area, they typically help expand the economy, which is advantageous to the area as a whole. New residents spend income, which in turn supports other growth. While the Companies have no estimates on the impact of this multiplier effect in Arizona, typical economic texts and articles indicate that the multiplier effect can be substantial. This multiplier effect positive externality could dwarf the utility-related negative externality. From the standpoint of the community, when the utility connects a new customer, a net positive externality could arise. In simple terms, the community would cheer the arrival of the new customer because he brings more value from economic growth than the cost he imposes on the utility system. This would argue against Hook-Up Fees, and may actually suggest that new load be subsidized. When a broader prospective is considered, the whole rationale behind Hook-Up Fees may be turned on its head. The issues here are broad and complex, and may move into public policy areas beyond the traditional purview of the Commission.

At the risk of being overly simplistic, one should note that states like Nevada and Arizona typically brag about being in the top 5 in growth among the 50 states. Low-growth states like South Dakota and Nebraska bemoan their situations, and struggle to maintain economic viability in small communities. States like Alabama and Kentucky have lured

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large industrial projects with subsidized infrastructure and/or tax incentives. Forty-six of the fifty states have tax incentives supporting and encouraging growth. The University of Arizona Eller School's Economics and Business Center, supported by our state legislature, presents growth as a good thing at its annual meeting. The Companies' point is simple here: conventional wisdom seems to hold that growth is a good thing, which will yield positive externalities.

The Commission should realize that a Hook-Up Fee may be at odds with more broad goals and objectives of this state. In the event that the Commission takes a more narrow approach by focusing on utility costs, the Companies hope that this can be accomplished with well designed line extension policies and/or in combination with socially optimal Hook-Up Fees and customer advances.

2. What are the fairness and equity issues associated with imposing or not imposing Hook-Up Fees?

a. Is it more equitable to have current utility customers pay through their rates?

b. Is it more equitable to assign those costs to new customers for whom the infrastructure must be built?

Response:

Please see the response to the first question. Hook-Up Fees may be inconsistent with system-wide rates, the long-established, traditional approach that is already in place. Fairness is in the eye of the beholder. There may be disagreement on what is "fair", and even what "fair" means.

Assuming Hook-Up Fees are established, if Hook-Up Fees are designed as a one-size-fits-all, there could be considerable equity issues. A few simple examples would be: (i) a new home placed where a home formerly was; (ii) a new home in an established neighborhood;

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(iii) a new commercial building where a former commercial building was; or (iv) a new commercial building in an established business development. As stated above in response to the first question, this is why the Companies prefer line extension policies designed to give more consideration to the circumstances of each individual Company and the specifics of each new service or project.

3. Should Hook-Up Fees be limited to extraordinary growth areas only? How do we define extraordinary growth?

Response:

The extraordinary growth the Companies are concerned with is growth that could adversely affect the financial integrity of the utilities. Hook-Up Fees may be helpful to a utility in cases of extraordinary growth and/or significant regulatory lag, and where an injection of cash is necessary to protect the financial integrity of the utility. In this circumstance, the financial integrity problem arises because of regulatory lag; the embedded cost in current rates cannot be adjusted quickly enough to generate the proper revenue required for the expenditures associated with serving the growing customer base.

Some possible solutions include:

1. Interim rate relief;
2. Construction Work In Progress;
3. Future test years;
4. Faster action on rate requests; and
5. Accelerated Depreciation.

4. What are the economic development implications?

- Who is helped?
- Who is hurt?

Response:

The Companies have not performed studies or analyses which would put them into an informed position to estimate the economic impact of varying Hook-Up Fees. However, economic theory suggests that the higher the fee, the greater the potential to see a

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detrimental impact on the housing market in the service territory where the fee is applicable. Negative impacts on the housing market can have ripple effects beyond the housing sector in faster growing areas. For example, reduced land and housing prices reduce area property owners' real wealth and access to credit, thus possibly leading to a contraction in the area's economy due to reduced aggregate demand. The key point here is that the detrimental effects may spread far beyond the individual or group that bears the initial impact.

5. What are the implementation issues?

- Is a phase-in period necessary?
- How should the phase-in be properly done?

Response:

There are always issues and implications when initiating a new fee. Given the potential impact on the state's economy, which is accustomed to high growth, the potential for quickly felt negative impacts in the housing sector, the multiplier effect which may be contractionary, and the regressive nature of this fee which disproportionately affects newly arriving low-income Arizonans, the Companies urge cautious movement toward any implementation.

6. What are the unique implications of assessing Hook-Up Fees to gas companies?

Response:

The obvious complexity when considering Hook-Up Fees for gas companies is the ability of customers to choose alternative energy sources. Given that gas companies are less capital intensive than electric companies, there is even less justification for gas Hook-Up Fees than for electric Hook-Up Fees, except in the type of extraordinary cases outlined in response to question 3.

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7. Effectiveness of Hook-Up Fees:

- Full or limited benefit? E.g. tax implications

Response:

The effectiveness of Hook-Up Fees to reduce future rate impacts and tax implications would be determined by how they were treated in a rate case, what costs are being recovered by the fees, and the ultimate impact on customer growth.

8. What are the competitive issues or concerns?

Response:

To the extent there are alternative providers or alternative sources of energy within the service territories of the Companies that do not require a Hook-Up Fee, it could impact customers' decisions as to where to locate and/or what energy source to use. From an economic standpoint, the Hook-Up Fee may increase the cost of growth, even though growth may provide a positive externality. Hook-Up Fees and growth have implications beyond the bounds of utility service.

9. Would Hook-Up Fees create customer confusion?

- What customer education would be necessary?

Response:

The customers should be informed of a new Hook-Up Fee and should be given adequate information to allow them to understand why the fee is being implemented.

10. What types of infrastructure should be included in a hook-Up fee?

Response:

As previously discussed, the Companies have not agreed that any fee is in the public interest. In the event that the fee has a net negative societal benefit, customers benefit from minimizing the amount of infrastructure recovered through these fees. Generation and

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transmission costs should not be recovered through the fee. If the Commission desires to recover some infrastructure costs, it should be limited to customer service and distribution assets. Transmission assets are currently regulated by FERC for TEP and UNS Electric, and it would be inappropriate to collect the cost of transmission services through a rate not approved by FERC. Generation assets pose other concerns, as discussed in response to the first question. The Companies encourage the Commission to make decisions on the future structure of electric utilities in Arizona. Hook-Up Fee design will vary with utility structure and the viability of Direct Access. In the event that generation is divested, the local distribution company need not calculate a Hook-Up Fee generation component. Generation will be competitively supplied, and generation suppliers will have no interest in whether the customers are old or new. Given that generation would be provided in a competitive market, it could be argued that a governmental entity or regulatory agency would be hard-pressed to set some price differential between old and new customers.

To the degree Hook-Up Fees are implemented, they should conform to marginal costs of service. If one thinks of the utility in terms of the vertically-integrated company, then one can either base marginal cost of the next planned unit or on a slice of the system, which will be some kind of weighted average accounting for plant types and in-service dates. The Companies suggest that the pros and cons of different approaches be argued on a case-by-case basis. A single approach should not be established at this time.

11. Should Hook-Up Fees attempt to pay for a new customer's full incremental cost?

Response:

No. Hook-Up Fees recovering full incremental costs from new customers will result in the new customer covering all his cost, plus a share of the embedded costs of serving the existing customers. The cost to serve the existing customer is recovered in existing rates. This seems extraordinarily inequitable. Ironically, this customer may provide positive

externalities to society as a whole when societal costs and benefits are added.

12. Should different sized customers pay different Hook-Up Fees?

Response:

Yes, to the extent that Hook-Up Fees are implemented.

13. What is your opinion about APS' proposal to treat Hook-Up Fees as revenue?

Response:

The Companies have questions about the proposal. What are the costs that will be recovered through the proposed Hook-up Fee? When would the revenues be recognized for Generally Accepted Accounting Principles ("GAAP") purposes (based on the cost it is developed to recover)? Will the Companies be able to reasonably rely upon the revenue source, especially given the downturn in the housing market and the unknown impact of adding additional cost to constructing a new home?

III. CONCLUSION.

The Companies respectfully request that the Commission consider these comments. The Companies look forward to participating in future discussions regarding the use of Hook-Up Fees for Arizona electric and natural gas utilities in the state of Arizona.

RESPECTFULLY SUBMITTED this 2nd day of November 2007.

TUCSON ELECTRIC POWER COMPANY
UNS ELECTRIC, INC.
UNS GAS, INC.

By _____

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EXHIBIT

GAS-3

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan T-1
Transportation of Customer-Secured Natural Gas

AVAILABILITY

This pricing plan is available to any qualifying Customer for transportation of natural gas by the Company from existing interconnects between the Company and upstream pipelines (herein called Receipt Point) to the Delivery Point(s) on the Company's system throughout its certificated Arizona Gas Service Area under the following conditions:

~~(a)~~1. The Company has available capacity to render the requested service without construction of any additional facilities, except as provided by ~~Section 8 of~~ this pricing plan under Facility Additions..

~~(b)~~2. The Customer has demonstrated to the Company's satisfaction the assurance of natural gas supplies and third-party transportation agreements with quantities, and for a term compatible with the service being requested from the Company.

~~(c)~~3. The Customer and the Company have executed a Transportation Agreement, and the Customer is to be the End-User.

~~(d)~~4. The Customer's gas to be transported is greater than 120,000 therms per year. A Customer receiving service from the Company at multiple locations may aggregate meters with annual consumption of no less than 50,000 therms per meter to qualify for this service provided that all meter locations are served under a single entity. In addition, the annual consumption of customers that are aggregated must be greater than 120,000 therms per year.

APPLICABILITY

This pricing plan shall apply to gas transported by the Company for Customer pursuant to the executed service agreement.

1. The basic transportation service rendered under this pricing plan shall consist of:

   (a) The receipt by the Company for the account of the Customer of the Customer's gas at the Receipt Point;

   (b) The transportation of gas through the Company's gas system for the account of the Customer; and

   (c) The delivery of gas after transportation by the Company for the account of the Customer at the Delivery Point(s).

2. Transportation: Service is firm and uninterrupted except for the following:

   (a) Curtailment in accordance with the Company's curtailment priority procedures;

   (b) When the Company determines it has insufficient capacity on its system or from its upstream pipeline; or

   (c) Customer's gas supply to the Company is insufficient to meet its requirement.

3. Any Customer served under this pricing plan that requests service under a sales pricing plan is ineligible to return to transportation service for a period of not less than twelve (12) months.

RATES

A discount from the following rates may be offered at the sole discretion of the Company if such discount is in the best interest of the Company and its ratepayers. The maximum amount that the Customer shall pay the Company monthly will be the sum of the following charges:

Customer Charge per Month: $10~~0~~.00 per meter

Volume Charge: An amount equal to the applicable unit transportation rate for each therm of Customer-secured gas metered and delivered to the Customer. The unit rates shall be as set forth in the currently effective Pricing Plan Summary. The volume charge will consist of the following:

(a) An amount equal to the applicable unit sales margin for each therm as set forth in the Customer's otherwise applicable sales pricing plan for each meter. This volume charge will cover the Company's Delivery Charge as specified in the currently effective gas sales pricing plan but not including the base cost of gas specified therein.

~~In no event will the minimum charge be less than that set forth in Section 4.1 below.~~

(b) An amount to reflect lost and unaccounted for gas as determined by the differential between the gas costs on a sales basis and gas costs on a purchase basis determined in the development of the currently effective, Purchased Gas Adjustment ("PGA"), Rate Rider No. RR-1. The Company, at its sole option, may allow lost and unaccounted for gas to be paid in kind.

(c) Any applicable imbalance charges as specified in Payment For Excess Quantities ~~Section 7~~ of this pricing plan.

(d) Any charges from upstream pipeline transporters or suppliers which have been incurred by the Company in excess of those specified in section (c) above and are deemed by the Company to be applicable to the transportation service rendered for the Customer under these pricing plans.

Minimun Charge: The minimum charge will be the Basic Customer Charge per Month plus $0.005 per therm.

ADMINISTRATIVE PROCEDURES

1. Processing Requests for Transportation Service: Requests for transportation hereunder shall be made by, and shall be deemed to be complete upon, the Customer providing the following information to the Company:

(a) Gas Quantities: The Maximum Daily Quantity applicable to the receipt point and the Maximum Daily Quantity applicable to each delivery point and estimated total quantities to be received and transported monthly over the delivery period should be stated individually in therms for each receipt point.

(b) Delivery Point(s): Point(s) of delivery by the Company to the Customer.

(c) Term of Service:
~~(i)~~i. Date of service requested to commence;
~~(ii)~~ii. Date service requested to terminate, if known; and
~~(iii)~~iii. Minimum term for transportation service shall be twelve (12) months.

(d) Performance: A statement from the Customer certifying that the Customer has or will have title to the gas to be delivered to the Company for transportation and has entered into or will enter into those arrangements necessary to assure all upstream transportation will be in place prior to the commencement of service under a Transportation Agreement. The Customer's Agent, if any, must be named.

Upon receipt of all of the information specified above, the Company shall prepare and tender to the Customer for execution a Transportation Agreement. If the Customer fails to execute the Transportation Agreement within thirty (30) days of the date tendered, the Customer's request shall be deemed null and void.

OPERATING PROCEDURES

~~1.~~1. Nominating and Scheduling of Gas Receipts and Deliveries: The Customer shall be responsible for contacting the upstream pipelines to arrange for the nominating and scheduling of receipts and deliveries hereunder, provided, that the Customer may designate one (1) other party to serve as his agent for such purpose.

The Customer or Customer's Agent shall be responsible for submitting nominations to the upstream pipeline and notifying the Company's designated representative in writing no later than one (1) hour prior to the upstream pipeline's nomination deadlines set forth in their FERC approved tariff. Such communication shall occur prior to the first of the month and within the month if there are changes to the nominations. The Customer is responsible for confirming the timely receipt of this information by the Company. The Company will confirm whether it has sufficient operational capacity to deliver all or a portion of the Customer's gas.

~~ii.~~2. Operating Information and Estimates: Upon request of the Company, the Customer shall from time to time submit its best estimates of the daily, monthly and annual volumes of gas to be transported; including peak day requirements, together with such other operating data as the Company may require in order to schedule its operations.

The Company may require large Customers whose contractually allowed maximum daily quantity exceeds 10,000 therms per day, whose usage is not predictable based on weather, and whose ratio of high to low daily usage exceeds ten (10) to inform the Company within 2 hours of any initiation or termination of gas usage exceeding an hourly rate of 1,000 therms per hour.

~~iii.~~3. Quantities: All quantities referred to under ~~in~~ Operating Procedures of this pricing plan ~~Section 6~~ shall be provided as dekatherms ("DTH") (one million British Thermal Units).

4. Deliverability: The Company shall not be liable for its failure to deliver gas when such failure is due to unavailability of gas supply or interruption of third party transportation services.

5. Other Operating Procedures: The Company may require additional information or enforce other operating procedures as deemed necessary in the Company's sole judgment, in order to coordinate gas volumes and the movement of gas through the upstream pipeline system to the Company's Arizona Gas Service Area. These additional operating procedures may be enforced upon verbal notice to each Customer or the Customer's Agent with twenty-four (24) hour notice of implementation.

6. Balancing: Balancing of thermally equivalent volumes of gas received and delivered shall be achieved as nearly as feasible on a daily basis, taking into account the Customer's right, subject to prior Company approval, to vary receipts and deliveries across the Company Distribution System. Customer monthly imbalances are defined as the difference between the Customer's total monthly metered quantities and the Customer's total scheduled transportation quantity. Customers are provided a monthly operating window, under which the Customer's cumulative imbalances must be within plus or minus 5 percent (+/- 5%) of the month's total of daily scheduled transportation quantities, plus any Company-approved imbalance adjustment quantity, or 1,500~~0,000~~ therms, whichever is greater. Imbalances established in excess of the applicable monthly operating window will be subject to imbalance charges as specified in Payment for Excess Quantities ~~Section 7~~ of this pricing plan. However, if the Customer has an imbalance outside this limit and contacts the Company before the end of the last business day of the month, the Customer will have a "cure period" of an additional 30 days to bring its imbalance within the limits before any imbalance charges specified in Payment for Excess Quantities ~~Section 7~~ are applied. Customer is then ineligible for a "cure period" for the following month. If in the Company's sole good faith judgment and operating conditions permit, the Company will increase the monthly operating window. Any imbalance (plus or minus) carried forward shall be considered first through the meter during the next daily or monthly period, as applicable.

Upon Customer request, the Company will permit electronic read-only access to the telemetering facilities described in Facility Additions of this pricing plan ~~Section 8~~ or provide daily meter reads each calendar day.

7. Adjustments: Periodically, volume adjustments may be made by the upstream pipelines or the Customer's agent. Therefore, actual daily volumes invoiced will be compared with daily nominated volumes. Should adjustments to the nominated volumes become necessary, such adjustments will be applied to the nomination for the month in which the volumes were delivered to the Customer for the purposes of determining the applicability of the provisions of this pricing plan.

8. Customer Default: The Company shall not be required to perform or continue service on behalf of any Customer that fails to comply with the terms contained in this pricing plan and the terms of the Customer's Transportation Service Agreement with the Company. The Company shall have the right to waive any one or more specific defaults by any Customer under any provision of this pricing plan or the service agreement, provided, however, that no such waiver shall operate or be construed as a waiver of any other existing or future default or defaults, whether of a like or different character.

9. Operational Curtailment: The Company reserves the right to impose, at any time, any reasonable operating conditions upon the transportation of the Customer's gas which the Company, in its sole good faith judgment, deems necessary to maintain safe and efficient operation of its distribution system, or to make the operating terms and conditions of service hereunder compatible with those of its upstream pipelines. Under such circumstances, the following conditions shall apply:

(a) Any Customer that does not comply with a notice of operational curtailment shall be subject to, in addition to any otherwise applicable charges, a penalty of $10.00 per DTH for all unauthorized quantities during the curtailment period.

(b) The Company shall endeavor to provide notice of such operational curtailment forty-eight (48) hours prior to the commencement of the delivery of gas.

(c) Notwithstanding condition (b), the Company may impose an operational curtailment on the current gas day. In the event an operational curtailment is imposed on the current gas day, a minimum one-hour grace period will be allowed before penalties begin to apply.

PAYMENT FOR EXCESS QUANTITIES

1. Customers will be assessed imbalance charges if an imbalance exists in excess of the applicable monthly operating window under the conditions set forth in Balacing described as part of Operating Procedures ~~Section 6.6~~ herein. The portion of any imbalance quantity established by a Customer in excess of the applicable monthly operating window is defined as an excess imbalance quantity. The imbalance charge will be based on the Company's short term purchases, where short term purchases are defined as gas for which the price is determined in the calendar month of use. In addition to the charges payable under this pricing plan, any monthly excess quantity shall be billed as follows:

(a) Positive Excess Imbalance

A positive excess imbalance exists when the Customer's scheduled transportation quantity exceeds the Customer's metered quantity by more than the applicable monthly operating window. The excess imbalance shall be retained by the Company and eliminated after the Customer's bill is credited as follows:

(i) The price of the positive imbalance gas for the applicable month shall be calculated as the weighted average cost per therm of the Company's least expensive short term purchases (including all upstream pipeline fuel and variable costs) for the aggregate positive imbalance volume associated with all T-1 customers. This weighted average cost per therm will be multiplied by the Customer's positive imbalance volume and the percentage associated with the Customer's "Percentage Excess Imbalance" in the "Positive" column in Table 1 below.

(b) Negative Excess Imbalance

A negative excess imbalance exists when the sum of the Customer's scheduled transportation quantity is less than the metered quantity by more than the applicable monthly operating window. The excess imbalance shall be eliminated after the Customer is billed as follows:

(i) The price of the negative imbalance gas for the applicable month shall be calculated as the weighted average cost per therm of the Company's most expensive short term purchases (including all upstream pipeline fuel, variable and capacity costs, at a 100% load factor) for the aggregate negative imbalance volume associated with all T-1 customers. This weighted average cost per therm will be multiplied by the Customer's negative imbalance volume and the percentage associated with the Customer's "Percentage Excess Imbalance" in the "Negative" column in Table 1 below.

Table 1

Percentage Excess Imbalance	Positive	Negative
Equal to or less than 5%	100%	100%
Over 5% and less than or equal to 15%	90%	110%
Over 15% and less than or equal to 20%	80%	120%
Over 20% and less than or equal to 30%	70%	130%
Over 30%	60%	140%

2. Should the Customer cease to utilize transportation service under this pricing plan, the entire remaining imbalance shall be settled pursuant to section Payment For Excess Quantities herein.~~Section 7.1.~~ For purposes of this settlement, no operating window applies.

3. Under no circumstances shall the ~~S~~section Payment For Excess Quantities ~~7.1~~ above be considered as giving the Customer any right to take excess quantity gas, other than as provided in Operating Procedures ~~by Section 6.6~~ hereof, nor shall the s~~S~~ection Payment For Excess Quantities ~~7.1~~ or payment thereunder be considered as a substitute for any other remedy available to the Company against the offending Customer for failure to respect its obligation to stay within its authorized quantities.

FACILITY ADDITIONS

Any facilities which must be installed by the Company to serve the Customer will be constructed in accordance with the Rules and Regulations as approved from time to time by the Arizona Corporation Commission. Telemetering facilities on each meter will be installed at the Customer's expense. Customers requiring telemetering facilities shall provide, at the Customer's expense, a dedicated telephone line for the Company's use in communicating with the telemetering facilities and will pay any and all costs associated with that phone line. Further, any existing special surcharges or minimum bill provisions designed to recover the cost of facilities for any Customer shall remain in effect and may serve to increase maximum allowable transportation rate levels pursuant to this pricing plan.

THIRD PARTY CHARGES

The Customer shall reimburse the Company for any charges rendered or billed to the Company by its upstream pipelines and by any other upstream transporter and gas gatherers, either before or after termination of the Transportation Agreement, which the Company, in its sole good faith judgment, determines have been incurred because of the transportation of Customer's gas hereunder and should, therefore, appropriately be borne by the Customer. Such charges, whether levied in dollars or gas, may include, but shall not be limited to, standby charges or reservation fees, prepayments, applicable taxes, applicable fuel reimbursement, shrinkage, lost and unaccounted for volumes, Gas Research Institute surcharges, penalty charges and filing fees.

The Customer will reimburse the Company for all such charges incurred by the Company as rendered, irrespective of the actual quantities of natural gas delivered to the Customer.

CONDITIONS FOR CONVERTING TO T-1 SERVICE

Any qualified Customer converting from gas sales service to service under this pricing plan is subject to the following conditions and requirements:

1. T-1 service will commence at the beginning of the first calendar month following the end of five (5) days after receipt of the customer service change request.

2. Customer will be billed or credited the Customer's pro rata share of the balance in the Company's PGA bank, calculated as follows:

(a) Starting from the later of the month of initiation of gas sales service by the Customer, or the date of initiation of the current PGA bank, through the last month of sales service, the Customer's actual therm usage will be multiplied, on a month-by-month basis, by the difference between the Company's actual commodity cost per therm and the Gas Cost component of the Basic Cost of Service Rate adjusted for any PGA and PGA Surcharge that may be in effect from time to time;

(b) The sum of these monthly calculated values equals the Customer's charge or credit due for conversion to service under this pricing plan;

(c) Customer charge or credit will be paid in twelve (12) equal monthly payments, including interest equal to the carrying charge rate applicable to the PGA bank at the time of conversion to service under this pricing plan.

3. If a Customer converts back to a pricing plan for gas sales service while the PGA Surcharge existing at the time of the switch to T-1 service is still in effect, such Surcharge will not be applicable to the Customer's billed usage for the period it remains in effect. However, any future PGA Surcharge that may be put into effect will be applicable to the Customer's billed usage.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

CONDITIONS

1. Transportation of Customer-owned natural gas hereunder shall be limited to natural gas of equal or higher quality than natural gas currently available from the Company's supplier(s). All gas delivered by the Company to the Customer shall be deemed to be the same quality as that gas received by the Company for transportation.

2. With respect to the Company's capacity to deliver gas at any particular time, the curtailment priority of any Customer served under this pricing plan shall be the same as the curtailment priority established for other Customers served pursuant to the Company's pricing plan which would otherwise be available to such Customer.

EXHIBIT

GAS-4

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan T-2
Transportation Service Using Dedicated Transmission Facilities

AVAILABILITY

This pricing plan is only available to any qualifying Customer for transportation of natural gas by the Company from dedicated interconnects between the Company and upstream pipelines (herein called Receipt Point) to the Delivery Point(s) on the Company's transmission system throughout its certificated Arizona Gas Service Area under the following conditions:

1. The Company has or will have available capacity to render the requested service utilizing facilities dedicated to the requirements of the Customer, except as provided under Facility Additions ~~by Section 8~~ hereof;

2. The Customer has demonstrated to the Company's satisfaction the assurance of natural gas supplies and third-party transportation agreements with quantities and for a term compatible with the service being requested from the Company;

3. The Customer and the Company have executed a Transportation Agreement, and the Customer is to be the End-User;

4. The Customer's requirement for gas to be transported is greater than 1,000 therms per day or 120,000 therms per year; and

5. The Customer is not taking service through dedicated facilities under the provisions of a special contract approved by the Arizona Corporation Commission ("ACC").

6. The Customer is classified as a utility that produces electricity.

APPLICABILITY

This pricing plan shall apply to gas transported by the Company for Customer pursuant to the executed service agreement.

1. The basic transportation service rendered under this pricing plan shall consist of:

   (a) The receipt by the Company for the account of the Customer of the Customer's gas at the Receipt Point;

   (b) The transportation of gas through the Company's gas system for the account of the Customer; and

   (c) The delivery of gas after transportation by the Company for the account of the Customer at the Delivery Point(s).

2. Transportation: Service is firm and uninterrupted except for the following:

   (a) Curtailment in accordance with the Company's curtailment priority procedures;

   (b) When the Company determines it has insufficient capacity on its system or from its upstream pipeline; or

(c) Customer's gas supply to the Company is insufficient to meet its requirement.

3. Any Customer served under this pricing plan is ineligible to obtain sales service without executing a special contract approved by the ACC.

RATES

A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

Customer Charge per month: $10~~50~~.00 per meter

Volume Charge: An amount equal to the applicable unit transportation rate for each therm of Customer-secured gas metered and delivered to the Customer. The unit rates shall be as set forth in the currently effective Pricing Plan Summary. The volume charge will consist of the following:

(a) An amount to fund the Company's low income rate program equal to the portion of the applicable unit sales margin for each therm included in rates as set forth in the Customer's otherwise applicable sales pricing plan for each meter.

(b) An amount to reflect lost and unaccounted for gas as determined by the differential between the gas cost on a sales basis and gas cost on a purchase basis determined in the development of the currently effective Purchased Gas Adjustment ("PGA"), Rate Rider No. RR-1. The Company at its sole option may allow lost and unaccounted for gas to be paid in kind.

(c) Any applicable imbalance charges as specified in Payment For Excess Quantities ~~Section 7~~ of this pricing plan.

(d) Any charges from upstream pipeline transporters or suppliers which have been incurred by the Company in excess of those specified in section (c) above and are deemed by the Company to be applicable to the transportation service rendered for the Customer under this pricing plan.

Reservation Charge: An annual charge to be billed in twelve (12) equal monthly installments equal to the fully allocated costs to provide the dedicated facilities necessary to serve the Customer as described more fully in Rates of this pricing plan~~Section 3.2 below~~.

Determined on the basis of a fully allocated cost study filed with and approved by the ACC in the context of a general rate case except when the request for service is non-coincident with a rate filing. In the latter case, the Reservation Charge will be computed by the Company including the following elements:

(a) Return and income taxes at the rate of return approved by the ACC in the Company's last general rate case computed on the basis of the installed costs of the dedicated facilities plus an allocation of other rate base items including, as appropriate: intangible, general and common plant investment, less any applicable accumulated depreciation and deferred taxes, an allowance for working capital and materials and supplies;

(b) Operations expense including all operating and maintenance expenses, depreciation and amortization expense, taxes other than income related to the dedicated facilities and allocated rate base;

(c) Allocated indirect expense including an appropriate portion of customer accounting, sales and information, and administrative and general expenses; and

(d) Any other allocated costs incurred either directly or indirectly to provide the requested service.

Special Surcharge: An annual charge to be computed on the basis of the twelve (12) months ending September of the prior year and billed beginning in January in equal monthly installments, computed as the sum of the following charges:

(a) The revenue requirements for any additional investments required to provide the service requested by Customer subsequent to the establishment of the currently effective Reservation Charge,

(b) Any non-recurring operating and maintenance expenses associated with the facilities dedicated to the Customer in the previous year, and

(c) Any extraordinary expenses incurred by the Company on behalf of the Customer not included in (a) or (b) above.

Minimum Charge: The minimum charge will be the sum of the Basic Customer Charge per Month, the monthly Reservation Charge and any monthly Special Surcharge.

ADMINISTRATIVE PROCEDURES

1. Processing Requests for Transportation Service: Requests for transportation hereunder shall be made by, and shall be deemed to be complete upon, the Customer providing the following information to the Company:

(a) Gas Quantities: The Maximum Daily Quantity applicable to the receipt point and the Maximum Daily Quantity applicable to each delivery point, and estimated total quantities to be received and transported monthly over the delivery period should be stated individually in therms for each receipt point.

(b) Delivery Point(s): Point(s) of delivery by the Company to the Customer.

(c) Term of Service:
i. Date service requested to commence;
ii. Date service requested to terminate, if known; and
iii. Minimum term for transportation service shall be twelve (12) months.

(d) Performance: A statement from the Customer certifying that the Customer has or will have title to the gas to be delivered to the Company for transportation and has entered into or will enter into those arrangements necessary to assure all upstream transportation will be in place prior to the commencement of service under a Transportation Agreement. The Customer's Agent, if any, must be named.

Upon receipt of all of the information specified above, the Company shall prepare and tender to the Customer for execution a Transportation Agreement. If the Customer fails to execute the Transportation Agreement within thirty (30) days of the date tendered, the Customer's request shall be deemed null and void.

2. Construction Requirements: In the event that the Customer's request for service requires the construction of additional transmission facilities not otherwise addressed in section Payment For Excess Quantities herof, ~~Section 7,~~ Extension of Lines, in the Company's current Rules and Regulations, the following additional provisions may apply:

(a) The Company may request an advance for engineering and design services based on the Company's estimate of the anticipated costs related to the requested dedicated facilities;

(b) Any advance for engineering and design will be refunded to the Customer on commencement of service;

(c) Actual engineering and design costs will be included in the dedicated facilities' costs and recovered as a part of the Reservation Charge;

(d) If the dedicated facilities are not placed in service for any reason, the Company may retain the advance;

(e) Prior to the initiation of construction of the dedicated facilities, the Company will provide an estimate of the total costs and resulting annual costs to Customer;

(f) The Company shall not be liable for any differences between actual construction costs and estimated costs;

(g) Customer may withdraw the request for service prior to initiation of construction; and

(h) The Customer may request that construction cease prior to completion. However, if the dedicated facilities are not completed or placed in service, the Customer is liable for service under the terms of this pricing plan as if the facilities had been completed, based on the total construction costs expended on behalf of the Customer.

OPERATING PROCEDURES

1. Nominating and Scheduling of Gas Receipts and Deliveries: The Customer shall be responsible for contacting the upstream pipelines to arrange for the nominating and scheduling of receipts and deliveries hereunder, provided, that the Customer may designate one (1) other party to serve as his agent for such purpose.

The Customer or Customer's Agent shall be responsible for submitting nominations to the upstream pipeline and notifying the Company's designated representative in writing no later than one (1) hour prior to the upstream pipeline's nomination deadlines set forth in their FERC approved tariff. Such communication shall occur prior to the first of the month and within the month if there are changes to the nominations. The Customer is responsible for confirming the timely receipt of this information by the Company. The Company will confirm whether it has sufficient operational capacity to deliver all or a portion of the Customer's gas.

2. Operating Information and Estimates: Upon request of the Company, the Customer shall from time to time submit its best estimates of the daily, monthly and annual volumes of gas to be transported; including peak day requirements, together with such other operating data as the Company may require in order to schedule its operations.

3. The Company may require large Customers whose contractually allowed maximum daily quantity exceeds 10,000 therms per day, whose usage is not predictable based on weather, and whose ratio of high to low daily usage exceeds ten (10) to inform the Company within 2 hours of any initiation or termination of gas usage exceeding an hourly rate of 1,000 therms per hour.

4. Quantities: All quantities referred to under Operating Procedures ~~in Section 6~~ shall be provided as dekatherms ("DTH") (one million British Thermal Units).

5. Deliverability: The Company shall not be liable for its failure to deliver gas when such failure is due to unavailability of gas supply or interruption of third party transportation services.

6. Other Operating Procedures: The Company may require additional information or enforce other operating procedures as deemed necessary in the Company's sole judgment, in order to coordinate gas volumes and the movement of gas through the upstream pipeline system to the Company's Arizona Gas Service Area. These additional operating procedures may be enforced upon verbal notice to each Customer or the Customer's Agent with twenty-four (24) hour notice of implementation.

7. ~~(f)~~ Balancing: Balancing of thermally equivalent volumes of gas received and delivered shall be achieved as nearly as feasible on a daily basis, taking into account the Customer's right, subject to prior Company approval, to

vary receipts and deliveries across the Company Distribution System. Customer monthly imbalances are defined as the difference between the Customer's total monthly metered quantities and the Customer's total scheduled transportation quantity. Customers are provided a monthly operating window, under which the Customer's cumulative imbalances must be within plus or minus 5 percent (+/- 5%) of the month's total of daily scheduled transportation quantities, plus any Company-approved imbalance adjustment quantity, or 1,500~~0,000~~ therms, whichever is greater. Imbalances established in excess of the applicable monthly operating window will be subject to imbalance charges as specified under Payment For Excess Quantities~~in Section 7~~ of this pricing plan. However, if the Customer has an imbalance outside this limit and contacts the Company before the end of the last business day of the month, the Customer will have a "cure period" of an additional 30 days to bring its imbalance within the limits before any imbalance charges specified under Payment For Excess Quantities ~~in Section 7~~ are applied. Customer is then ineligible for a "cure period" for the following month. If in the Company's sole good faith judgment and operating conditions permit, the Company will increase the monthly operating window. Any imbalance (plus or minus) carried forward shall be considered first through the meter during the next daily or monthly period, as applicable.

8. Upon Customer request, the Company will permit electronic read-only access to the telemetering facilities described under Facility Additions ~~in Section 8~~ or provide daily meter reads each calendar day.

9. ~~(g)~~ Adjustments: Periodically, volume adjustments may be made by the upstream pipelines or the Customer's agent. Therefore, actual daily volumes invoiced will be compared with daily nominated volumes. Should adjustments to the nominated volumes become necessary, such adjustments will be applied to the nomination for the month in which the volumes were delivered to the Customer for the purposes of determining the applicability of the provisions of this pricing plan.

10. ~~(h)~~ Customer Default: The Company shall not be required to perform or continue service on behalf of any Customer that fails to comply with the terms contained in this pricing plan and the terms of the Customer's Transportation Service Agreement with the Company. The Company shall have the right to waive any one or more specific defaults by any Customer under any provision of this pricing plan or the service agreement, provided, however, that no such waiver shall operate or be construed as a waiver of any other existing or future default or defaults, whether of a like or different character.

11. ~~(i)~~ Operational Curtailment: The Company reserves the right to impose, at any time, any reasonable operating conditions upon the transportation of the Customer's gas which the Company, in its sole good faith judgment, deems necessary to maintain safe and efficient operation of its distribution system, or to make the operating terms and conditions of service hereunder compatible with those of its upstream pipelines. Under such circumstances, the following conditions shall apply:

~~(a)~~12. Any Customer that does not comply with a notice of operational curtailment shall be subject to, in addition to any otherwise applicable charges, a penalty of $10.00 per DTH for all unauthorized quantities during the curtailment period.

~~(b)~~13. The Company shall endeavor to provide notice of such operational curtailment forty-eight (48) hours prior to the commencement of the delivery of gas.

~~(c)~~14. Notwithstanding condition (b), the Company may impose an operational curtailment on the current gas day. In the event an operational curtailment is imposed on the current gas day, a minimum one-hour grace period will be allowed before penalties begin to apply.

PAYMENT FOR EXCESS QUANTITIES

1. Customers will be assessed imbalance charges if an imbalance exists in excess of the applicable monthly operating window under the conditions set forth under Balacing described as part of Operating Procedures ~~in Section 6.6~~ herein. The portion of any imbalance quantity established by a Customer in excess of the applicable monthly operating window is defined as an excess imbalance quantity. The imbalance charge will be based on the Company's short term purchases, where short term purchases are defined as gas for which the price is determined in the calendar month of use. In addition to the charges payable under this pricing plan, any monthly excess quantity shall be billed as follows:

(a) Positive Excess Imbalance

A positive excess imbalance exists when the Customer's scheduled transportation quantity exceeds the Customer's metered quantity by more than the applicable monthly operating window. The excess imbalance shall be retained by the Company and eliminated after the Customer's bill is credited as follows:

(i) The price of the positive imbalance gas for the applicable month shall be calculated as the weighted average cost per therm of the Company's least expensive short term purchases (including all upstream pipeline fuel and variable costs) for the aggregate positive imbalance volume associated with all T-2 customers. This weighted average cost per therm will be multiplied by the Customer's positive imbalance volume and the percentage associated with the Customer's "Percentage Excess Imbalance" in the "Positive" column in Table 1 below.

(b) Negative Excess Imbalance

A negative excess imbalance exists when the sum of the Customer's scheduled transportation quantity is less than the metered quantity by more than the applicable monthly operating window. The excess imbalance shall be eliminated after the Customer is billed as follows:

(i) The price of the negative imbalance gas for the applicable month shall be calculated as the weighted average cost per therm of the Company's most expensive short term purchases (including all upstream pipeline fuel, variable and capacity costs, at a 100% load factor) for the

aggregate negative imbalance volume associated with all T-2 customers. This weighted average cost per therm will be multiplied by the Customer's negative imbalance volume and the percentage associated with the Customer's "Percentage Excess Imbalance" in the "Negative" column in Table 1 below.

Table 1

Percentage Excess Imbalance	Positive	Negative
Equal to or less than 5%	100%	100%
Over 5% and less than or equal to 15%	90%	110%
Over 15% and less than or equal to 20%	80%	120%
Over 20% and less than or equal to 30%	70%	130%
Over 30%	60%	140%

2. Should the Customer cease to utilize transportation service under this pricing plan, the entire remaining imbalance shall be settled pursuant to section Payment For Excess Quantities herein. For purposes of this settlement, no operating window applies.

3. Under no circumstances shall the section Payment For Excess Quantities above be considered as giving the Customer any right to take excess quantity gas, other than as provided in Operating Procedures hereof, nor shall the section Payment For Excess Quantities or payment thereunder be considered as a substitute for any other remedy available to the Company against the offending Customer for failure to respect its obligation to stay within its authorized quantities.

FACILITY ADDITIONS

Any facilities which must be installed by the Company to serve the Customer will be constructed in accordance with the Rules of Service as approved from time to time by the ACC. Telemetering facilities on each meter will be installed at the Customer's expense. Customers requiring telemetering facilities shall provide, at the Customer's expense, a dedicated telephone line for the Company's use in communicating with the telemetering facilities and will pay any and all costs associated with that phone line. Further, any existing special surcharges or minimum bill provisions designed to recover the cost of facilities for any Customer shall remain in effect and may serve to increase maximum allowable transportation rate levels pursuant to this pricing plan.

THIRD PARTY CHARGES

The Customer shall reimburse the Company for any charges rendered or billed to the Company by its upstream pipelines and by any other upstream transporter and gas gatherers, either before or after termination of the Transportation Agreement, which the Company, in its sole good faith judgment, determines have been incurred because of the transportation of Customer's gas hereunder and should, therefore, appropriately be borne by the Customer. Such charges,

whether levied in dollars or gas, may include, but shall not be limited to, standby charges or reservation fees, prepayments, applicable taxes, applicable fuel reimbursement, shrinkage, lost and unaccounted for volumes, Gas Research Institute surcharges, penalty charges, and filing fees.

The Customer will reimburse the Company for all such charges incurred by the Company as rendered, irrespective of the actual quantities of natural gas delivered to the Customer.

CONDITIONS FOR CONVERTING TO T-2 SERVICE

Any qualified Customer converting from gas sales service to service under this pricing plan is subject to the following conditions and requirements:

1. T-2 service will commence at the beginning of the first calendar month following the end of five (5) days after receipt of the customer service change request or completion of any required facilities, whichever is later.

2. Customer will be billed or credited the Customer's pro rata share of the balance in the PGA bank accumulated while served under the Company's sales pricing plan, calculated as follows:

   (a) Starting from the later of the month of initiation of gas sales service by the Customer, or the date of initiation of the current PGA bank, through the Customer's last month of sales service, the Customer's actual therm usage will be multiplied, on a month-by-month basis, by the difference between the Company's actual commodity cost per therm and the Gas Cost component of the Base Cost of Service Rate adjusted for any PGA and PGA Surcharge that may be in effect from time-to-time;

   (b) The sum of these monthly calculated values equals the Customer's charge or credit due for conversion to service under this pricing plan;

   (c) Customer charge or credit will be paid in twelve (12) equal monthly payments, including interest equal to the carrying charge rate applicable to the PGA bank at the time of conversion to service under this pricing plan.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan T-2
Transportation Service Using Dedicated Transmission Facilities

CONDITIONS

1. Transportation of Customer owned natural gas hereunder shall be limited to natural gas of equal or higher quality than natural gas currently available from the Company's supplier(s). All gas delivered by the Company to the Customer shall be deemed to be the same quality as that gas received by the Company for transportation.

2. With respect to the Company's capacity to deliver gas at any particular time, the curtailment priority of any Customer served under this pricing plan shall be the same as the curtailment priority established for other Customers served pursuant to the Company's pricing plan, which would otherwise be applicable to such Customer.

ORIGINAL

NEW APPLICATION

BEFORE THE ARIZONA CORPORATION COMMISSION

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

EXHIBIT
UNSG-9
ADMITTED

Arizona Corporation Commission
DOCKETED
JAN 25 2008
DOCKETED BY

G-04204A-08-0050

IN THE MATTER OF THE REQUEST BY UNS GAS, INC. FOR A WAIVER OF CERTAIN REQUIREMENTS IN DECISION 66028.	DOCKET NO. G-04204A-

REQUEST FOR WAIVER

UNS Gas, Inc. ("UNS Gas" or the "Company"), through undersigned counsel, respectfully requests that the Arizona Corporation Commission ("Commission") issue an order waiving certain requirements in Commission Decision No. 66028 (July 3, 2003). These requirements are no longer necessary, as detailed below, however, they remain in the Commission's database until they are formally waived or otherwise removed by Commission action. UNS Gas has worked with the Commission's Staff to update compliance matters and UNS Gas believes that this request for a waiver is the proper means by which these requirements can be closed.

I. INTRODUCTION.

Decision No. 66028 approved the acquisition by UniSource Energy Corporation ("UniSource Energy") of Citizens Communications Company's ("Citizens") Arizona gas and electric assets. Pursuant to that Decision, UniSource Energy, and subsequently UNS Gas, was to (i) refrain from the use of contract personnel for the performance of operation and maintenance functions, such as leak surveys and valve maintenance;[1] and (ii) independently inspect all new construction work performed by contractor personnel regarding the installation of new service lines and main extensions.[2]

[1] Decision No. 66028, page 22, lines 18-20.
[2] Decision No. 66028, page 22, lines 25-26.

UNS Gas requests that these requirements[3] be waived, as they are no longer necessary for the reasons set forth below:

II. THE REQUIREMENTS SHOULD BE WAIVED.

A. Use of contract personnel.

Currently, most local distribution companies ("LDC") in Arizona have the flexibility to utilize outside contractor personnel to perform O&M work including, but not limited to, leak survey, valve maintenance and leak repair. Citizens also utilized contractor personnel for this type of work prior to the acquisition by UniSource Energy of Citizens' Arizona gas and electric assets. UNS Gas requests that the Commission allow it the same flexibility to utilize outside contractor personnel for the performance of operation and maintenance functions, a practice from which other LDCs in the state continue to benefit.

B. Inspection of work performed by contractor personnel.

UNS Gas also requests that it no longer be required to independently inspect all new construction work performed by contractor personnel regarding the installation of new service lines and main extensions. At the time of the acquisition, Citizens utilized four (4) different pipeline contractors for installation of new lines and main extensions, including Northern Pipeline ("NPL"), PIPEco, Henkels and McCoy, and Bogie Construction. On January 1, 2006, UNS Gas entered into a sole contractor partnership, or alliance, with NPL whereby NPL agreed to perform all contractor installation work for new service lines and main extensions.[4]

UNS Gas field inspections for new construction have consistently indicated that UNS Gas has performed in accordance with required State, Federal and Company regulatory standards and Commission Pipeline Safety Inspection Audits for the past four (4) years have been excellent. UNS Gas' history and track record for a commitment to standardization, detail, and safety have been documented and acknowledged by Commission Pipeline Safety Staff on multiple occasions.

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[3] Decision No. 66028, page 22, section L, nos. 3 and 6.

[4] NPL performs contractor installation work for all of the major LDCs within Arizona.

In the event the Commission approves UNS Gas' request for a waiver of the inspection requirement, the Company will still continue its on-going practice of self-inspection.

III. CONCLUSION.

Pipeline safety will not diminish with a waiver from the requirements discussed above and Commission Pipeline Safety Staff has indicated its support of this request for a waiver. UNS Gas believes that the requirements discussed above are no longer necessary for the reasons set forth herein, and a waiver by the Commission of those requirements is in the public interest.

WHEREFORE, UNS Gas respectfully requests that the Commission issue its order waiving certain requirements in Decision No. 66028.

RESPECTFULLY SUBMITTED this 25th day of January 2008.

UNS GAS, INC.

By Michelle Livengood

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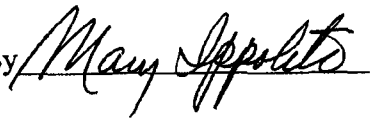
By 

ORIGINAL

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UNSG-10
ADMITTED

BEFORE THE ARIZONA CORPORATION

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COMMISSIONERS

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GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR A WAIVER OF CERTAIN REQUIREMENTS IN DECISION 66028.	DOCKET NO. G-04204A-08-0050 **STAFF'S RESPONSE TO UNS GAS' APPLICATION FOR WAIVER OF CONDITIONS IN DECISION NO. 66028**

On January 25, 2008, UNS Gas Inc. ("UNS Gas" or "Company") filed a request that the Arizona Corporation Commission ("Commission") waive certain conditions placed on the Company by Decision No. 66028 (July 3, 2003). Among other conditions, Decision No. 66028 requires UNS Gas to (1) not use contracted personnel to perform operating and maintenance functions and additionally (2) to independently inspect all contracted work performed in the installation of new service lines and main extensions. Pipeline Safety Section Staff ("Staff") has reviewed the Company's application and supports the request for a waiver of the two conditions.

Decision No. 66028 approved UNS Gas' predecessor, UniSource Energy Corporation's ("UniSource") acquisition of the gas and electric assets of Citizens Communications Company ("Citizens"). In order to ameliorate potential customer service impacts related to the transfer in ownership, Decision No. 66028 ordered UniSource, and now UNS Gas, to not use contracted personnel to perform operating and maintenance functions. As the Company notes in its application, it is normal within the industry to permit contractors to perform this work and indeed, it was the practice of Citizens to use contractors for just this work prior to the transfer.

Staff notes that the safety record of UNS Gas has been excellent to date. To the extent that the condition prohibiting the use of contracted employees was a measure to ensure a consistent level of customer service, Staff believes that the condition is no longer necessary. UNS Gas has progressed beyond the transitional phase of operations immediately following its acquisition of

Citizens' assets. Customer service does not appear to be in jeopardized by the change. Further, allowing UNS Gas to utilize contracted personnel to perform these services may permit cost savings that in turn can be passed on to the ratepayers' benefit.

Likewise, Decision No. 66028 obliges UNS Gas to independently inspect all work performed by contracted personnel regarding the installation of new service lines and main extensions. This condition was also intended to be an interim condition to ensure consistent quality of customer service during the transition of ownership. Staff believes that UNS Gas' operating history has sufficiently demonstrated that neither safety nor service will be jeopardized if the condition is waived. Additionally, as explained by UNS Gas' application, it has entered a cost saving contractual relationship with one of the available contractors engaged to perform such work.

Staff believes that under the present circumstances, UNS Gas' application for waiver of the two described conditions should be approved.

RESPECTFULLY SUBMITTED this 14th day of February, 2008.

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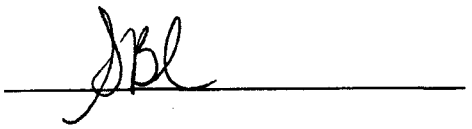
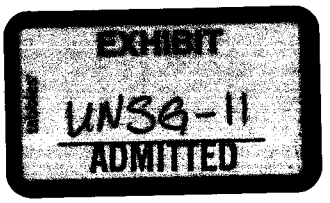


BEFORE THE ARIZONA CORPORATION COMMISSION

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



IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-____

Direct Testimony of

Karen G. Kissinger

on Behalf of

UNS Gas, Inc.

November 7, 2008

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Exhibit KGK–1 PriceWaterhouseCoopers Accounting & Reporting Manual SEC 4940 - Topic 13 Revenue Recognition

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Karen G. Kissinger and my business address is 4350 East Irvington Road, Tucson, Arizona, 85714.

Q. By whom are you employed and what is your position?

A. I am Vice President, Controller, and Chief Compliance Officer for UniSource Energy Corporation ("UniSource Energy"). I am also Vice President and Controller of UNS Gas, Inc., UniSource Energy's indirect subsidiary ("UNS Gas" or the "Company").

Q. What are your duties and responsibilities as Vice President and Controller?

A. My present functional areas of responsibility include internal and external financial reporting, plant and property accounting, payroll, accounts payable, tax planning and tax compliance reporting, and energy settlements for all UniSource Energy owned utilities. I am also responsible for the UniSource Energy Corporation Compliance Program, which focuses on corporate policies, practices, and procedures that are designed to assure that UniSource Energy is in compliance with laws, regulations, and corporate policies.

Q. Would you please describe your education, background and experience?

A. I received a Bachelor of Arts Degree in Spanish from the University of Virginia in 1977. I received a Master of Business Administration with a Concentration in Accounting from the University of Arizona in 1982. I am a Certified Public Accountant licensed to practice in the State of Arizona. I am a member of the American Institute of Certified Public Accountants and the Arizona State Society of Certified Public Accountants. Before joining Tucson Electric Power Company ("TEP")[1] in 1991, I was employed by

[1] TEP is a subsidiary of UniSource Energy Corporation and an affiliate of UNS Gas, Inc.

Deloitte Haskins & Sells, and its successor by merger, Deloitte & Touche, in the audit department for approximately eight and one-half years. I was designated by Deloitte & Touche as a public utility specialist, and provided audit and consulting services to a client base comprised of both public and cooperative electric utilities. Since 1991, I have been employed by TEP as Vice President and Controller and as UniSource Energy Corporation's Vice President and Controller since the time of its formation. In 2003, I was assigned the additional responsibility of Chief Compliance Officer. I was named the Vice President and Controller of UNS Gas when it was formed in 2003.

Q. What is the purpose of your Direct Testimony in this proceeding?

A. My Direct Testimony supports UNS Gas' rate request in this proceeding. I am the sponsoring witness for the historical accounting and tax data reflected in UNS Gas' rate case Application included in the "E" Schedules – (Financial Statements and Statistical Schedules). I also sponsor the depreciation, property tax and the income tax pro forma adjustments in Schedules B and C.

II. PRO FORMA ADJUSTMENTS.

Q. Please explain the consideration of pro forma adjustments in the rate case process.

A. Public utility rates are based on the reasonable and prudently-incurred costs of providing safe, reliable service. The revenue requirement underlying rates is developed on the basis of a test-year that reflects a level of operating revenues and expenses and net plant investment that is representative of normal conditions that may be expected to exist during the time that resulting rates will be in effect. The revenue requirement calculation also contains a component that is intended to afford the utility a reasonable opportunity to achieve a fair rate of return, as authorized by the respective regulatory authority.

Pro forma adjustments are made to recorded test-year amounts that are not required for the provision of service or that are not representative of the levels expected to occur during the period in which the new rates will be in effect. Such adjustments may be made in the form of eliminations, annualizations, or normalizations.

Elimination adjustments are made to remove out-of-period or non-recurring transactions, or items that are not costs or revenues related to the provision of utility service; thus, not eligible for reflection in revenue requirements.

Annualization adjustments are made to reflect the full, 12-month revenue or expense level of certain components of operating income. Annualization adjustments are typically computed using end-of-test-year quantities and the most current known and measurable prices and rates. Examples in this case include restating test-year operating revenues to reflect customer levels at the end of the test-year, adjusting payroll expense to reflect current salary rates and changes in employee levels during the test-year, and adjusting recorded depreciation expense to reflect the full effect of plant additions and retirements during the test-year.

Normalization adjustments reflect that the recorded test-year operating revenues and expenses may not be representative of a normal level for ratemaking purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions eligible for reflection in revenue requirements are incurred at intervals less frequent than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the test-year may not be viewed as "normal," thus requiring a restatement for ratemaking purposes. Normalization adjustments are made in such instances when a test-year level of revenues or expenses is not representative of what would be expected on an on-going

basis. Examples in this case include the adjustment for bad debt expense and the overtime factor implicit in the payroll adjustment.

Q. Were the pro forma adjustments that you are sponsoring in your testimony prepared by you or under your supervision?

A. Yes, they were.

Q. Have the pro forma adjustments for which you are responsible in this rate filing been computed in accordance with sound ratemaking principles and all applicable rules and policies of the Arizona Corporation Commission ("Commission")?

A. Yes. To the best of my knowledge, all of the adjustments that I am sponsoring have been so calculated.

III. RATE BASE ADJUSTMENT.

A. Accumulated Deferred Income Tax.

Q. Please explain the Accumulated Deferred Income Tax adjustment.

A. The adjustment reduces rate base for the computed balance of Accumulated Deferred Income Taxes ("ADIT"), a source of non-investor capital, based on adjusted test-year rate base and operating results, and the Company's existing income tax ratemaking authority.

Q. What are deferred income taxes?

A. Deferred income taxes represent the tax effect of differences that arise between the time period when revenues and expenses are recognized for financial reporting purposes and when they are considered for income tax return purposes. For public utilities, the largest such difference is that which exists as a result of the use of accelerated methods and

shorter lives in computing tax depreciation as compared with the manner in which book depreciation is computed. The process of apportioning income taxes among accounting periods is referred to as "interperiod tax allocation." For this purpose, it is useful to distinguish between "timing differences" and "permanent differences."

Timing differences represent differences between book income before income taxes and taxable income which originate in one or more periods, and reverse or turn around, in one or more subsequent periods. Because of their capital intensity, the difference between book and tax depreciation is typically the largest timing difference affecting public utilities. Expenses that are deducted by utilities currently for tax purposes, but deferred on the books as regulatory assets for future recognition in rates is another example of a timing difference.

Permanent differences exist between book income and taxable income, and do not reverse in subsequent periods. Examples of permanent differences include non-taxable interest income from municipal bonds and non-deductible lobbying expenses.

Deferred income taxes are computed for timing differences, but not for permanent differences. The typical accounting for deferred taxes involves recognition of a deferred income tax provision (expense) on the income statement for the tax effect of the timing differences, with a corresponding entry made to a balance sheet accumulated deferred income tax reserve account. As the timing differences reverse over time, the deferred tax component of income tax expense becomes negative and balance of the reserve account is extinguished.

Q. How do deferred income taxes affect public utility ratemaking?

A. The reflection of deferred income taxes in ratemaking is labeled "normalization". Some regulatory bodies permit utilities to recognize deferred income taxes associated with all book-tax timing differences in ratemaking ("full normalization"), while others only permit the recognition of certain timing differences required by the Internal Revenue Code to be recognized in utility ratemaking ("partial normalization"). To the extent that normalization is permitted in ratemaking, the resulting deferred income taxes are reflected as a component of income tax expense, with the corresponding balance sheet reserve for accumulated deferred taxes deducted from rate base as non-investor capital, reflecting the availability of such amounts for plant investment or operating purposes between the time they are collected from customers and ultimately remitted to taxing authorities.

Q What income tax ratemaking authority has been granted to UNS Gas?

A. Citizens Communications Company ("Citizens") operated various properties throughout the state of Arizona, each having its separate designated service territory, rate schedules and service rules. For gas operations, Citizens operated under separate divisions in northern Arizona and southern Arizona. The Santa Cruz Gas Division, which was based in Santa Cruz County, Arizona, was authorized full normalization in Decision No. 53103 (July 8, 1982). The pro forma income tax expense calculations prepared in connection with the 1996 Citizens Northern Arizona Gas Division rate case, Decision No. 59875 (October 29, 1996), and also those prepared for the Citizens gas rate cases in progress at the time of the asset purchase approved in Decision No. 66028 (July 3, 2003), clearly indicate the use of a full normalization of all books – tax timing differences. For ratemaking purposes, both of the gas plant properties acquired from Citizens have been permitted to provide deferred income taxes in rate making for all timing differences. In Decision No. 66028, the Commission also approved all of the gas divisions being

combined into one entity for ratemaking purposes. No changes were made to such income tax authority in Decision No. 70011 (November 27, 2007), UNS Gas' most recent rate order.

Q. How was the tax cost of the gas plant assets determined in connection with computing the ADIT balance deducted from rate base as of the end of the test-year?

A. As I mentioned, in accordance with the Settlement Agreement approved by Decision No. 66028, the two Citizens gas divisions were merged into a single entity, UNS Gas. Upon their acquisition by UniSource Energy, a new tax basis reflecting the actual amounts for the acquired assets was established. For rate making purposes, such tax basis is adjusted to reflect the fixed acquisition discount established by the Commission in Decision No. 66028. Upon acquisition of the assets by UNS Gas from Citizens, all book-tax timing differences arising since that time have been fully normalized by UNS Gas, consistent with the prior rate treatment afforded to the assets when owned by Citizens.

IV. OPERATING INCOME ADJUSTMENTS.

Q. Please explain the Depreciation Expense adjustment.

A. The Depreciation Expense adjustment is computed to reflect in pro forma operating expense an annual depreciation amount based on depreciable plant in service as of the end of the test-year, and book depreciation rates as presented in the Direct Testimony of witness Dr. Ronald E. White and accepted by the Commission in Decision No. 70011. In addition, the calculation of the adjustment properly considers the effects of depreciation associated with vehicles that are charged to clearing accounts or expense categories other than depreciation.

Q. Please explain the Property Tax adjustment.

A. The Property Tax adjustment is intended to reflect in pro forma test-year operating expenses an amount based on final, adjusted plant in service at the end of the test-year, using the 2009 statutory assessment ratio of 22.0%, and the most currently known average property tax rates. To the extent that more current average tax rate information becomes available during the conduct of this rate case, the Company will update that part of the tax adjustment.

Q. Please explain the Income Tax Expense adjustment.

A. The Income Tax Expense adjustment is computed with the intent to reflect in pro forma test-year operating expenses an amount of income taxes based on final adjusted operating revenues, operating expense, and rate base. It is computed in two parts. The first part is pro forma current income tax expense, the tax liability computed as though an actual income tax return was being prepared on final adjusted test-year taxable operating income. For this purpose, it was necessary to identify all operating book-tax differences ("Schedule M items"), both timing and permanent, and then recompute based on adjusted test-year operating revenues and expenses, if necessary. The tax deduction for interest was computed using a synchronization methodology reflecting final adjusted rate base and the weighted cost of debt in the capital structure.

The second part of the income tax calculation is deferred income tax expense. Deferred income taxes are computed on the Schedule M items representing timing differences for which the Company has obtained normalization ratemaking authority from the Commission as previously described in my Direct Testimony.

V. SUMMARY OF "E" SCHEDULES – FINANCIAL STATEMENTS AND STATISTICAL SCHEDULES.

Q. Please explain the Company's "E" Schedules in its filing.

A. These schedules, as is the same for all other sections of this rate case filing, were prepared in accordance with the filing requirements contained in the Arizona Administrative Code ("AAC") R14-2-103. Schedules E-1 through E-9 contain annual financial statements, and key operating statistics and financial data, extracted from the Company's regulatory books of account.

Q. On what basis are the regulatory books of account of UNS Gas maintained?

A. The Company's regulatory books of account are maintained in accordance with the Uniform System of Accounts of the Federal Energy Regulatory Commission ("FERC"), as required by AAC R14-2-312.G.2.

Q. Have there been any significant changes to the Company's accounting policies or principles since the test year in UNS Gas' last rate case?

A. Yes. As a result of adopting FAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* ("FAS 158"), in December 2006, UNS Gas recognized its allocable share of the underfunded status of the defined benefit pension and other postretirement employee benefit (OPEB) plans as a liability. For the pension plan, the underfunded status was measured as the difference between the fair value of the plan's assets and the projected benefit obligation. For the OPEB plan, the underfunded status was measured as the difference between the cumulative amounts recognized in expense to date and the projected accumulated postretirement benefit obligation. The adjustment required to recognize the pension liability on adoption of this statement resulted in recognition of a regulatory asset. UNS Gas recorded its share of the required

increase in the OPEB obligation as an adjustment to Accumulated Other Comprehensive Loss as the Commission allows UNS Gas to recover other postretirement costs through rates only as benefit payments are made. FAS 158 impacts the balance sheet only, and has no impact on the UNS Gas income statement.

Q. Have the financial statements been audited?

A. Yes. The calendar years 2007, 2006, 2005, 2004 and 2003 (from inception date) financial statements were audited by the firm of PricewaterhouseCoopers LLP (Independent Certified Public Accountants).

Q. Please describe Schedule E-1.

A. Schedule E-1 contains the comparative balance sheets of UNS Gas for the test-year ending June 30, 2008, and the two prior years ending December 31, 2007, and December 31, 2006.

Q. Please describe Schedule E-2.

A. This schedule sets forth comparative income statements for the test-year ending June 30, 2008, and the two prior years ending December 31, 2007 and December 31, 2006. The income statement for the test-year supports the actual test period income statement shown on Schedules C-1 and C-2.

Q. Please describe Schedule E-3.

A. This schedule presents the comparative statements of cash flows for the test-year ending June 30, 2008 and the two prior calendar years ending December 31, 2007 and December 31, 2006.

Q. Please describe Schedule E-4.

A. This schedule reports the changes that occurred in stockholders' equity (deficit) during the period beginning January 1, 2005 and ending June 30, 2008. Changes occurring each year in the amounts of the various elements of stockholders' equity are reflected.

Q. Please describe Schedule E-5.

A. Page 1 of Schedule E-5 presents a summary of the balances in the various gas utility plant account categories and accumulated depreciation at June 30, 2008 and December 31, 2007, and the net changes therein during the six months ended June 30, 2008, with plant in service presented on a functional basis. Pages 2, 3 and 4 of Schedule E-5 present the same information on a more detailed basis, by individual gas plant account.

Q. Please describe Schedule E-6.

A. Schedule E-6 contains Operating Income Statements for the test-year ending June 30, 2008 and the two prior calendar years ended December 31, 2007 and December 31, 2006. Retail revenues are reported by rate class. Operating Expenses are reported by major category.

Q. Please describe Schedule E-7.

A. This schedule reports key gas operating statistics, in a comparative format, for the test-year ending June 30, 2008 and the two prior calendar years ending December 31, 2007 and December 31, 2006.

Q. Please describe Schedule E-8.

A. This schedule shows the taxes charged to operating expenses by tax type for the test-year ending June 30, 2008 and the two prior calendar years ended December 31, 2007 and December 31, 2006.

Q. Please describe Schedule E-9.

A. This schedule is intended to disclose important facts required for a proper understanding of the financial statements. A summary of the Company's significant accounting policies is set forth in Note 2 of the Notes to Financial Statements in the Company's audited financial statements for the year ended December 2007, included at Schedule E-9.

VI. RECOGNITION OF HOOK-UP FEES AS REVENUE.

Q. Are there any accounting issues that you would like to address that arose out of UNS Gas' last rate case, Docket No. G-04204A-06-0463, Decision No. 70011 ("the last UNS Gas rate case")?

A. Yes. In the last UNS Gas rate case the Company was ordered to "investigate fully the issue of developer contributions and present in its next rate case viable alternatives to the proposal adopted herein, including but not limited to nonrefundable hook-up fees and other measures that would hold harmless existing customers and required greater contributions to ensure that growth pays for itself." [Decision No. 70011, page 85.] One of the issues raised in the Commission's generic hook-up fee docket is whether hook-up fees could be structured in such a manner as to facilitate recording them as current period revenues rather than as contributions in aid of construction ("CIAC"), which are recorded on the balance sheet as a reduction of utility plant, as has been past practice in Arizona.

In the pending Tucson Electric Power Company rate case, I was asked through discovery to inquire whether our auditors had any written opinions on whether hook-up fees could be recorded as revenue upon receipt in GAAP financial statements. Our auditors directed us to a section of their Accounting and Reporting Manual in which they discuss the Security and Exchange Commission's ("SEC's") concerns with recognition of fees up front as revenue when services are performed over a period of time. I have attached this

section of their Accounting and Reporting Manual, SEC 4940 Topic 13 Revenue Recognition, as Exhibit KGK-1 to my Direct Testimony here. Based upon this literature, it very well may be difficult to devise a hook-up fee that would satisfy the SEC's revenue recognition requirements so that hook-up fees could be reported as current period income for GAAP financial statement purposes in the year received. At a minimum, we believe that the Company would need a strong accounting order from the Commission, along with tariff and ordering language in the rate order, that are explicit as to the accounting treatment of the fees.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT

KGK-1

SEC 4940 - Topic 13 Revenue Recognition

f. Nonrefundable up-front fees

Question 1

Facts: Registrants may negotiate arrangements pursuant to which they may receive nonrefundable fees upon entering into arrangements or on certain specified dates. The fees may ostensibly be received for conveyance of a license or other intangible right or for delivery of particular products or services. Various business factors may influence how the registrant and customer structure the payment terms. For example, in exchange for a greater up-front fee for an intangible right, the registrant may be willing to receive lower unit prices for related products to be delivered in the future. In some circumstances, the right, product, or service conveyed in conjunction with the nonrefundable fee has no utility to the purchaser separate and independent of the registrant's performance of the other elements of the arrangement. Therefore, in the absence of the registrant's continuing involvement under the arrangement, the customer would not have paid the fee. Examples of this type of arrangement include the following:

- A registrant sells a lifetime membership in a health club. After paying a nonrefundable "initiation fee," the customer is permitted to use the health club indefinitely, so long as the customer also pays an additional usage fee each month. The monthly usage fees collected from all customers are adequate to cover the operating costs of the health club.

- A registrant in the biotechnology industry agrees to provide research and development activities for a customer for a specified term. The customer needs to use certain technology owned by the registrant for use in the research and development activities. The technology is not sold or licensed separately without the research and development activities. Under the terms of the arrangement, the customer is required to pay a nonrefundable "technology access fee" in addition to periodic payments for research and development activities over the term of the contract.

- A registrant requires a customer to pay a nonrefundable "activation fee" when entering into an arrangement to provide telecommunications services. The terms of the arrangement require the customer to pay a monthly usage fee that is adequate to recover the registrant's operating costs. The costs incurred to activate the telecommunications service are nominal.

- A registrant charges users a fee for non-exclusive access to its web site that contains proprietary databases. The fee allows access to the web site for a one-year period. After the customer is provided with an identification number and trained in the use of the database, there are no incremental costs that will be incurred in serving this customer.

- A registrant charges a fee to users for advertising a product for sale or auction on certain pages of its web site. The company agrees to maintain the listing for a period of time. The cost of maintaining the advertisement on the web site for the stated period is minimal.

- A registrant charges a fee for hosting another company's web site for one year. The arrangement does not involve exclusive use of any of the hosting company's servers or other equipment. Almost all of the projected costs to be incurred will be incurred in the initial loading of information on the host company's internet server and setting up appropriate links and network connections.

Question: Assuming these arrangements qualify as single units of accounting under EITF Issue 00-21(36), when should the revenue relating to nonrefundable, up-front fees in these types of arrangements be recognized?

(36) The staff believes that the vendor activities associated with the up-front fee, even if considered a deliverable to be evaluated under EITF Issue 00-21, will rarely provide value to the customer on a standalone basis.

Interpretive Response: The staff believes that registrants should consider the specific Facts and circumstances to determine the appropriate accounting for nonrefundable, upfront fees. Unless the up-front fee is in exchange for products delivered or services performed that represent the culmination of a separate earnings process, (37) the deferral of revenue is appropriate.

(37) See Concepts Statement 5, footnote 51, for a description of the "earning process."

In the situations described above, the staff does not view the activities completed by the registrants (i.e., selling the membership, signing the contract, enrolling the customer, activating telecommunications services or providing initial set-up services) as discrete earnings events. (38) The terms, conditions, and amounts of these fees typically are negotiated in conjunction with the pricing of all the elements of the arrangement, and the customer would ascribe a significantly lower, and perhaps no, value to elements ostensibly associated with the up-front fee in the absence of the registrant's performance of other contract elements. The fact that the registrants do not sell the initial rights, products, or services separately (i.e., without the registrants' continuing involvement) supports the staff's view. The staff believes that the customers are purchasing the ongoing rights, products, or services being provided through the registrants' continuing involvement. Further, the staff believes that the earnings process is completed by performing under the terms of the arrangements, not simply by originating a revenue generating arrangement.

(38) In a similar situation, lenders may collect nonrefundable loan origination fees in connection with lending activities. The FASB concluded in Statement 91 that loan origination is not a separate revenue-producing activity of a lender, and therefore, those nonrefundable fees collected at the outset of the loan arrangement are not recognized as revenue upon receipt but are deferred and recognized over the life of the loan (paragraphs 5 and 37).

While the incurrence of nominal up-front costs helps make it clear that there is not a separate earnings event in the telecommunications example above, incurrence of substantive costs, such as in the web hosting example above, does not necessarily indicate that there is a separate earnings event. Whether there is a separate earnings event should be evaluated on a case-by-case basis. Some have questioned whether revenue may be recognized in these transactions to the extent of the incremental direct costs incurred in the activation. Because there is no separable deliverable or earnings event, the staff would generally object to that approach, except where it is provided for in the authoritative literature (e.g., Statement 51).

Supply or service transactions may involve the charge of a nonrefundable initial fee with subsequent periodic payments for future products or services. The initial fees may, in substance, be wholly or partly an advance payment for future products or services. In the examples above, the on-going rights or services being provided or products being delivered are essential to the customers receiving the expected benefit of the up-front payment. Therefore, the up-front fee and the continuing performance obligation related to the services to be provided or products to be delivered are assessed as an integrated package. In such circumstances, the staff believes that up-front fees, even if nonrefundable, are earned as the products and/or services are delivered and/or performed over the term of the arrangement or the expected period of performance(39) and generally should be deferred and recognized systematically over the periods that the fees are earned. (40)

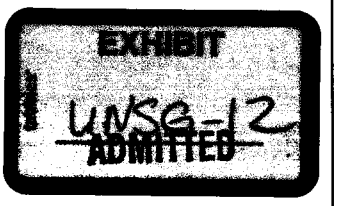
(39) The revenue recognition period should extend beyond the initial contractual period if the relationship with the customer is expected to extend beyond the initial term and the customer continues to benefit from the payment of the up-front fee (e.g., if subsequent renewals are priced at a bargain to the initial up-front fee).

(40) A systematic method would be on a straight-line basis, unless evidence suggests that revenue is earned or obligations are fulfilled in a different pattern, in which case that pattern should be followed.

Some propose that revenue should be recognized when the initial set-up is completed in cases where the on-going obligation involves minimal or no cost or effort and should, therefore, be considered perfunctory or inconsequential. However, the staff believes that the substance of each of these transactions indicates that the purchaser is paying for a service that is delivered over time. Therefore, revenue recognition should occur over time, reflecting the provision of service. (41)

(41) Concepts Statement 5, paragraph 84(d).

BEFORE THE ARIZONA CORPORATION COMMISSION



COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-04204A-08-0571

Rebuttal Testimony of

Karen G. Kissinger

on Behalf of

UNS Gas, Inc.

July 8, 2009

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Karen G. Kissinger. My business address is 4350 East Irvington Road, Tucson, Arizona.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Testimony is filed on behalf of UNS Gas, Inc. ("UNS Gas").

Q. What is the purpose of your Rebuttal Testimony in this proceeding?

A. The purpose of my Rebuttal Testimony is to: (i) address the adjustments to Accumulated Deferred Income Taxes ("ADIT") proposed by Staff witness Dr. Thomas Fish and RUCO witness Mr. Ralph C. Smith.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

II. STAFF'S PROPOSED ADIT ADJUSTMENT.

Q. What issue do you wish to address with respect to the ADIT adjustment of Dr. Thomas Fish?

A. In his Direct Testimony, Dr. Fish has proposed to disallow the costs of the Company's Supplemental Executive Retirement Plan ("SERP"). In a related adjustment, Dr. Fish proposes to remove from rate base an ADIT adjustment related to the SERP.

Q. Why do you believe the ADIT adjustment is inappropriate?

A. The amount that Dr. Fish has identified as ADIT related to SERP ($38,994) he believes to be included in rate base. But this amount is not actually in UNS Gas' proposed rate base, and therefore it is not necessary to remove it. The amount that Dr. Fish identified is deferred income tax expense and is included in Income Tax Expense on Schedule C-1. The ADIT related to SERP was not included in rate base in the Company's Application, and no rate base adjustment is required if the recovery of SERP expense is disallowed.

Q. Does this conclude your comments regarding the Direct Testimony of Dr. Fish?

A. Yes, it does.

III. RUCO'S PROPOSED ADIT ADJUSTMENT.

Q. What issue do you wish to address with respect to the ADIT adjustment of Mr. Ralph C. Smith?

A. Mr. Smith has proposed to reduce rate base by the amount of ADIT related to Compensation & Benefits timing differences ($423,669).

Q. Why is there ADIT associated with the Company's compensation & benefits expense?

A. For ratemaking accounting purposes, the cost of vacation, pension benefits, and stock-based compensation are recognized as expense on an accrual basis. That is, the expense is reflected in the income statement as the employees perform services and earn the future benefit. For income tax purposes, vacation expense is not deductible until the vacation pay is paid to the employee and pension expense is only deductible when contributions within the IRS limitations are made to the pension trust. Stock based compensation is deductible when the payment is actually made to employees. This difference in timing of recognition

causes deferred income assets to be recorded on the balance sheet for the amount of income taxes paid by the Company related to these items.

Q. Why should the deferred income tax assets be included in rate base?

A. The deferred income tax assets reflect an investment made by the Company on the ratepayer's behalf. Pension, vacation expense and stock based compensation are calculated on an accrual basis and are a component of operating expense reflected in rates. However, because these benefits are not tax deductible in the same period that the benefit is recognized, the Company is required to pay income taxes currently. The company is entitled to earn a return on the capital used to pay these income taxes on the ratepayer's behalf.

Q. Has the inclusion of ADIT related to non-rate base items been allowed in previous rate cases decided by the Commission?

A. Yes. The ADIT related to vacation and pension expense were included in rate base in the Company's Application in its last rate case, Docket No. G-04204A-06-0463. Staff and RUCO did not object, and these items of ADIT were included in the final rate base numbers accepted by the Commission. These same items have also been accepted by the Commission in rate cases presented by UNS Gas affiliates, Tucson Electric Power Company and UNS Electric, Inc. RUCO's proposed adjustment is another example of RUCO challenging accepted Commission-approved methods.

Q. How was the ADIT related to stock based compensation treated in previous rate cases?

A. The ADIT related to stock based compensation was not allowed by the Commission as a component of rate base in the last case. However, this adjustment occurred because the

recovery of the underlying expense was disallowed in calculating cost of service, and in those circumstances the adjustment to ADIT is appropriate.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.