

COMMONWEALTH OF KENTUCKY  
BEFORE THE PUBLIC SERVICE COMMISSION

**RECEIVED**  
JUN 28 2007  
PUBLIC SERVICE  
COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL )  
GAS COMPANY, INC. FOR ) CASE NO. 2007-00089  
AN ADJUSTMENT OF RATES )

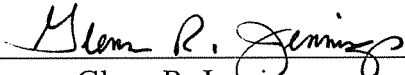
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**CERTIFICATION**

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The undersigned, Glenn R. Jennings, states that he is Chairman of the Board, President and Chief Executive Officer of Delta Natural Gas Company, Inc., a corporation, ("Delta") and certifies that he supervised the preparation of the responses of Delta to the Second Data Request of Commission Staff to Delta herein and that the responses are true and accurate to the best of the undersigned's knowledge, information and belief formed after a reasonable inquiry.

Dated this 28th day of June, 2007.

  
\_\_\_\_\_  
Glenn R. Jennings

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF DELTA NATURAL )  
GAS COMPANY, INC. FOR AN ) 2007-00089  
ADJUSTMENT OF RATES )

SECOND PSC DATA REQUEST  
DATED JUNE 7, 2007

FILED IN SUPPORT OF PROPOSED  
CHANGES IN RATES

JUNE 28, 2007

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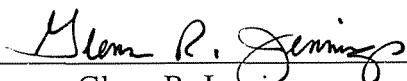
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Dated this 28th day of June, 2007.

  
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Glenn R. Jennings





**DELTA NATURAL GAS CO., INC.**  
**SECOND DATA REQUEST OF COMMISSION STAFF**  
**2007-00089**

**ELECTRONIC FILE INDEX**

<u>Item #</u>	<u>File Name</u>	<u>CD#</u>
2d	Item 2d - CEP Rate Mechanism.xls	PSC 2 CD 1
22	Item 22 - Participant Test.xls	PSC 2 CD 1
22	Item 22 - RIM Test.xls	PSC 2 CD 1
22	Item 22 - TRC Test.xls	PSC 2 CD 1
22	Item 22 - Program Administrator Cost Test.xls	PSC 2 CD 1
23b	Item 23b - Appliance Cost Study.xls	PSC 2 CD 1
23c	Item 23c - Rebate Comparison.xls	PSC 2 CD 1
26d	Item 26d - CEP Budget Determinants.xls	PSC 2 CD 1
28	Item 28 - 2002-2005 CRS Adjustment.xls	PSC 2 CD 1
46	PSC 46 Delta Cost of Service Study 2006.xls	PSC 2 CD 1
50(f)	2PSC -50(f) Plant Balances .xls	PSC 2 CD 1
50(f)	2PSC-50(f) Module1.bas	PSC 2 CD 1
50(f)	2PSC-50(f) Module2.bas	PSC 2 CD 1



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

1. Refer to the Application, the Financial Exhibit, pages 2 and 3 of 8. Has Delta redeemed any of the 7.0 percent debentures that mature in February 2023? If yes, provide full details of the redemption, including the amount redeemed, the date of redemption, and all costs associated with the redemption.

**RESPONSE:**

The only redemption of the 7% Debenture relates to a payment made in December, 2005, in the amount of \$10,000.00 to the Bank of New York. This is a payment to a deceased beneficial owner. There were no costs associated with the redemption.

Sponsoring Witness:

John B. Brown



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

2. Refer to the Application, Tab 7.
  - a. The tariff pages which describe the Conservation and Efficiency Program ("CEP") state that the costs could include the cost of consultants. Identify the type of consultants Delta may have occasion to hire for this program.
  - b. Explain how Delta will be able to determine whether a change in usage is the result of the CEP or another factor.
  - c. Explain why the balance adjustment includes interest.
  - d. Provide an example of the detailed calculation that Delta would submit for the CEP.

RESPONSE:

- a. Currently, the projected expenses budgeted for the CEP does not include the cost of any consultants. Delta would hire consultants for the CEP program if the Commission requests a specific evaluation or analysis for the CEP which requires consultants with specialized skills required to perform the analysis.
- b. There is not a method to determine if an individual customer who participated in the CEP has decreased usage as a result of the CEP or any other factors. For example a customer could have replaced their furnace with a high-efficiency model which qualified them for a rebate under the CEP. Their billing records for the subsequent year would show a decline in usage, but there is no way to tell if this decline is offset by an increase in the thermostat settings or other factors. For this reason the CEP uses conservation estimates to determine the Ccf conserved for the purposes of calculating the CEPLS and CPI. Although actual conservation can be greater or less than the estimated conservation, we feel the estimates calculated are conservative.

For example, if a participant installs a high efficiency forced air gas furnace, the Ccf conserved for the purposes of calculating the CEPLS and the CPI is 100.02 Ccf regardless of the actual efficiency gains. To derive this estimate, we calculated the annual usage for a 90% furnace and the average CCF conserved as compared to utilizing an 80% or 70% efficient furnace. For all of the appliance rebates, the Ccf conserved is based on estimates for the type of appliance which has been installed. The conservation estimates are on page 14 of Exhibit MDW-1.

**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

- c. The CEP rates are calculated on an annual basis. Any under/over recovery of CEP costs for the previous year will flow through the balance adjustment in the next year. The interest component ensures the customers and Delta are made whole for the time-value of money related to any balance adjustment.
  
- d. See attached. The attached schedules are an illustrative example of the calculations which would be submitted to the Commission on an annual basis. To illustrate how the mechanism would work on an on-going basis the example has been provided for two years. The amounts used in this example are based upon the budgeted participation levels for the CEP in 2008 and 2009. The budgeted customer participation levels and expenditures are included in Exhibit MDW-1.

Sponsoring Witness:

Matthew D. Wesolosky

Delta Natural Gas Company, Inc.  
 Conservation/Efficiency Program  
 Billing Factor Calculation

Program Begins: November 1, 2007  
 Program Year End: October 31, 2008  
 Rate Effective: February 1, 2009

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CEPCR - Conservation/Efficiency Program Cost Recovery

Program Costs		
Program Rebates	\$	120,400
Customer Awareness	\$	25,000
Program Administration	\$	10,000
Supplies	\$	10,920
Program Overhead	\$	800
Total Program Costs		<u>\$ 167,120</u>
<b>TOTAL CEPCR</b>		<b>\$ 167,120</b>

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CEPLS - Conservation/Efficiency Program Lost Sales

Current Year Program Participation (Schedule A)

Rate	# of Participants	CCF Conserved	Distribution Charge	Lost Sales
Residential Furnace	540	35,582.8	\$ 0.4159	\$ 14,799
Residential Water Heater	70	3,326.2	0.4159	1,383
Energy Audit	46	1,380.0	0.4159	574
Total Current Year Lost Sales	<u>656</u>	<u>40,289.0</u>		<u>\$ 16,756</u>
Cumulative Prior Years Participation (Schedule B)	-	-		\$ -
<b>Total CEPLS</b>	<b>656</b>	<b>40,289.0</b>		<b>\$ 16,756</b>

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CEPI - Conservation/Efficiency Program Incentive

Program Benefits (Schedule C)	\$	309,891
Less: Program Costs	<u>\$</u>	<u>(167,120)</u>
Net Resource Savings	\$	142,771
Incentive Percentage		15%
<b>CEPI</b>		<b>\$21,416</b>

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CEPBA - Conservation/Efficiency Program Balancing Adjustment

Balancing of rate mechanism not effective until the 2009 program year.

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CEPRC - Conservation/Efficiency Recovery

Estimated Residential Sales 17,800,000 Ccf

	Recovery Amount	Rate, per Ccf
CEPCR	\$ 167,120	\$ 0.8141
CEPLS	\$ 16,756	0.0816
CEPI	\$ 21,416	0.1043
CEPBA	\$ -	-
<b>TOTAL DSM</b>	<b>\$ 205,292</b>	<b>\$ 1.0000</b>

Estimated Recovery during 2010 Program Year:

2/1/9-10/31/9	\$	143,704
11/1/9-1/31/10		61,588
<b>Total Recovery</b>	<u>\$</u>	<u>205,292</u>



Delta Natural Gas Company, Inc.  
 Conservation/Efficiency Program  
 Schedule A - Current Year Participation Detail

Program Year End: October 31, 2008

	(1)	(1)		(1)	
	Program	CCF Conservation		Rebate	
	Participants	Per Participant	Total	Amount	Total
<b><u>A. High Efficiency Heating Savings</u></b>					
1. High Efficiency Forced Air Furnaces	160	100.02	16,003.2	\$ 400	\$ 64,000
2. High Efficiency Dual Fuel Units	20	20.85	417.0	300	6,000
3. High Efficiency Gas Space Heating	20	16.33	326.6	100	2,000
4. High Efficiency Gas Logs/Fireplaces	340	55.40	18,836.0	100	34,000
<b><u>B. High Efficiency Water Heating Savings</u></b>					
1. High Efficiency Holding Tank Models	63	45.11	2,841.9	200	12,600
2. High Efficiency Power Vent Models	6	62.62	375.7	250	1,500
3. High Efficiency On-Demand Models	1	108.59	108.6	300	300
<b><u>C. Energy Audits</u></b>					
1. Residential Energy Audits	46	30.00	1,380.0		
<b>Total</b>	<b>656</b>		<b>40,289.0</b>	<b>\$</b>	<b>120,400</b>

(1) Amounts based on budget and guidelines in CEP program document, submitted as Exhibit MDW-1



Delta Natural Gas Company, Inc.  
 Conservation/Efficiency Program  
 Schedule C - Calculation of Program Benefits

Program Year End: October 31, 2008

Current Year Conservation (Ccf) 40,289.0 per Schedule A

Year	CCF Conserved	Projected Gas Cost*	Commodity Savings
2008	40,289.0	\$ 1.155	\$ 46,534
2009	40,289.0	\$ 1.128	45,446
2010	40,289.0	\$ 1.093	44,036
2011	40,289.0	\$ 1.065	42,908
2012	40,289.0	\$ 1.045	42,102
2013	40,289.0	\$ 1.036	41,739
2014	40,289.0	\$ 1.044	42,062
2015	40,289.0	\$ 1.035	41,699
2016	40,289.0	\$ 1.011	40,732
2017	40,289.0	\$ 1.007	40,571
<b>Total Commodity Savings</b>	<b>402,890.4</b>		<b>\$ 427,829</b>
Discount Rate			6.50%
<b>Program Benefits</b>			<b>\$309,891</b>
(present value of commodity savings)			

\*Based on Department of Energy "Annual Energy Outlook", converted to per ccf residential cost

Delta Natural Gas Company, Inc.  
 Conservation/Efficiency Program  
 Billing Factor Calculation

Program Year End: October 31, 2009  
 Rate Effective: February 1, 2010

CEPCR - Conservation/Efficiency Program Cost Recovery

Program Costs			
Program Rebates	\$	144,050	
Customer Awareness	\$	20,000	
Program Administration	\$	10,000	
Supplies	\$	1,400	
Program Overhead	\$	800	
Total Program Costs		\$	176,250
<b>TOTAL CEPCR</b>		<b>\$</b>	<b>176,250</b>

CEPLS - Conservation/Efficiency Program Lost Sales

Current Year Program Participation (Schedule A)

Rate	# of Participants	CCF Conserved	Distribution Charge	Lost Sales
Residential Furnace	600	40,606.8	\$ 0.4159	\$ 16,888
Residential Water Heater	80	3,794.9	0.4159	1,578
Energy Audit	70	2,100.0	0.4159	873
<b>Total Current Year Lost Sales</b>	<b>750</b>	<b>46,501.7</b>		<b>\$ 19,339</b>
Cumulative Prior Years Participation (Schedule B)	656	40,289.0		\$ 16,756
<b>Total CEPLS</b>	<b>1,406</b>	<b>86,790.7</b>		<b>\$ 36,095</b>

CEPI - Conservation/Efficiency Program Incentive

Program Benefits (Schedule C)	\$	352,731
Less: Program Costs	\$	(176,250)
Net Resource Savings	\$	176,481
Incentive Percentage		15%
<b>CEPI</b>		<b>\$26,472</b>

CEPBA - Conservation/Efficiency Program Balancing Adjustment

Recovery			
Prior Year			
Amount to be Recovered	11/1/08-1/31/09	\$	-
Actual	11/1/08-1/31/09		-
Current Year			
Amount to be Recovered	2/1/09-10/31/09		143,704
Actual	2/1/09-10/31/09		(156,845)
Under(Over) Recovery		\$	(13,141)
Average 3 month Commercial Paper Rate for year-ended 10/31/09			5.17% (estimated for illustration purposes)
Interest on under(over) recovery		\$	(679)
<b>TOTAL CEPBA</b>		<b>\$</b>	<b>(13,820)</b>

CEPRC - Conservation/Efficiency Recovery

Estimated Residential Sales 17,444,000 Ccf

	Recovery Amount	Rate, per Ccf
CEPCR	\$ 176,250	\$ 0.0101
CEPLS	\$ 36,095	0.0021
CEPI	\$ 26,472	0.0015
CEPBA	\$ (13,820)	(0.0008)
<b>TOTAL DSMRC</b>	<b>\$ 224,997</b>	<b>\$ 0.0129</b>

Estimated Recovery during 2010 Program Year:		
2/1/10-10/31/10	\$	157,498
11/1/10-1/31/11		67,499
<b>Total Recovery</b>	<b>\$</b>	<b>224,997</b>

Delta Natural Gas Company, Inc.  
 Conservation/Efficiency Program  
 Schedule A - Current Year Participation Detail

Program Year End: October 31, 2009

	(1)	(1)		(1)	
	Program	CCF Conservation		Rebate	
	Participants	Per Participant	Total	Amount	Total
<b><u>A. High Efficiency Heating Savings</u></b>					
1. High Efficiency Forced Air Furnaces	208	100.02	20,804.16	\$ 400	\$ 83,200
2. High Efficiency Dual Fuel Units	26	20.85	542.10	300	7,800
3. High Efficiency Gas Space Heating	26	16.33	424.58	100	2,600
4. High Efficiency Gas Logs/Fireplaces	340	55.40	18,836.00	100	34,000
<b><u>B. High Efficiency Water Heating Savings</u></b>					
1. High Efficiency Holding Tank Models	72	45.11	3,247.92	200	14,400
2. High Efficiency Power Vent Models	7	62.62	438.34	250	1,750
3. High Efficiency On-Demand Models	1	108.59	108.59	300	300
<b><u>C. Energy Audits</u></b>					
1. Residential Energy Audits	70	30.00	2,100.00		
<b>Total</b>	<b>750</b>		<b>46,501.69</b>	<b>\$</b>	<b>\$ 144,050</b>

(1) Amounts based on budget and guidelines in CEP program document, submitted as Exhibit MDW-1

Delta Natural Gas Company, Inc.  
 Conservation/Efficiency Program  
 Schedule B - Cumulative Prior Years Program Participation

Program Year End: October 31, 2009

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Cumulative Total
<b>Program Participants</b>											
<b>A. High Efficiency Heating Savings</b>	160										160
1. High Efficiency Forced Air Furnaces	20										20
2. High Efficiency Dual Fuel Units	20										20
3. High Efficiency Gas Space Heating	340										340
4. High Efficiency Gas Logs/Fireplaces	-										
<b>B. High Efficiency Water Heating Savings</b>	63										63
1. High Efficiency Holding Tank Models	6										6
2. High Efficiency Power Vent Models	1										1
3. High Efficiency On-Demand Models	-										
<b>C. Energy Audits</b>	46										46
1. Residential Energy Audits	46										46
<b>Total</b>	<b>656</b>										<b>656</b>

**Total Conservation (Ccf)**

<b>A. High Efficiency Heating Savings</b>	16,003.2										16,003.2
1. High Efficiency Forced Air Furnaces	417.0										417.0
2. High Efficiency Dual Fuel Units	326.6										326.6
3. High Efficiency Gas Space Heating	18,836.0										18,836.0
4. High Efficiency Gas Logs/Fireplaces	-										
<b>B. High Efficiency Water Heating Savings</b>	2,841.9										2,841.9
1. High Efficiency Holding Tank Models	375.7										375.7
2. High Efficiency Power Vent Models	108.6										108.6
3. High Efficiency On-Demand Models	-										
<b>C. Energy Audits</b>	1,380.0										1,380.0
1. Residential Energy Audits	1,380.0										1,380.0
<b>Total</b>	<b>40,289.0</b>										<b>40,289.0</b>

**Total Lost Sales**

\$ 16,756

Delta Natural Gas Company, Inc.  
 Conservation/Efficiency Program  
 Schedule C - Calculation of Program Benefits

Program Year End: October 31, 2009

Current Year Conservation (Ccf) 46,501.7

Year	CCF Conserved	Projected Gas Cost*	Commodity Savings
2009	46,501.7	1.128	\$ 52,454
2010	46,501.7	1.093	50,826
2011	46,501.7	1.065	49,524
2012	46,501.7	1.045	48,594
2013	46,501.7	1.036	48,176
2014	46,501.7	1.044	48,548
2015	46,501.7	1.035	48,129
2016	46,501.7	1.011	47,013
2017	46,501.7	1.007	46,827
2018	46,501.7	1.030	47,897
<b>Total Commodity Savings</b>	<b>465,016.9</b>		<b>\$ 487,988</b>

Discount Rate 6.50%

**Program Benefits \$352,731**  
 (present value of commodity savings)

\*Based on Department of Energy "Annual Energy Outlook", converted to per ccf residential cost





**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

3. Refer to the Application, Tab 8, Sheet No. 24. Delta has altered its tariff language for the Budget Billing Plan to incorporate any amounts to be settled into the subsequent budget year.
  - a. Describe how Delta currently handles any settlement amounts in the Budget Billing Plan.
  - b. Explain the rationale for changing this portion of the tariff.
  - c. Explain the extent to which any delays in receiving under-collections during the winter may affect Delta's cash flow.

**RESPONSE:**

- a. Since 1997, with the implementation of its new Customer Information System, any amounts due or overpayments reflected on the July bill have automatically been rolled over into the next year's budget calculation.
- b. The wording has simply been changed to reflect the automatic rollover instead of a settle-up.
- c. During the winter months, Delta constantly monitors budget customers' accounts and adjustments are made as necessary to minimize significant under-collection balances.

Sponsoring Witness:

Matthew D. Wesolosky



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

4. Refer to the Application, Tab 8, Original Sheet No. 44. In its Customer Rate Stabilization ("CRS") tariff, Delta proposes to recover the Commission's and the Attorney General's ("AG") incremental cost for one employee each. Explain why Delta is limiting the additional cost to one employee per agency.

**RESPONSE:**

One full-time employee works approximately 2,000 hours in a given year. Since the review period for the CRS is 45 days, (excluding weekends) this equates to approximately 8 people working full-time on the review for the 45 day period. We feel that the equivalent of eight people reviewing the filing would be more than adequate since the filing would have a more focused review. Please refer to KYPSC DR 2-27d for a more detailed explanation of the proposed review procedures. Based on these procedures, we feel that a process can be created to promote an efficient review of the adjustment, which would take less than 2,000 hours.

Sponsoring Witness:

Matthew D. Wesolosky



**DELTA NATURAL GAS COMPANY, INC.  
CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST  
DATED 6/07/07**

5. Refer to the Application, Tab 24. Provide the calculations used to produce the exhibit.

RESPONSE:

See attached.

Sponsoring Witness:

Matthew D. Wesolosky

Delta Natural Gas Company  
KYPSC DR2-5

	Billings @ Current Rate (normalized)	Proposed Increase	Billings Proposed Rate	Number of Bills	Average Bill		Difference	% Change
					Present Rates	Proposed Rates		
Residential	30,871,718	3,845,405	34,717,123	385,374	\$ 80.11	\$ 90.09	\$ 9.98	12.5%
Small Non-Residential	9,172,300	471,298	9,643,598	51,808	\$ 177.04	\$ 186.14	\$ 9.10	5.1%
Large Non-Residential	13,312,267	621,056	13,933,323	10,280	\$ 1,294.97	\$ 1,355.38	\$ 60.41	4.7%
Interruptible	456,049	-	456,049	90	\$ 5,067.21	\$ 5,067.21	\$ -	0.0%
On-System Transportation	4,394,332	528,775	4,923,107	2,470	\$ 1,779.08	\$ 1,993.16	\$ 214.08	12.0%
Off-Systems Transportation	2,484,947	95,575	2,580,522	74	\$ 33,580.36	\$ 34,871.92	\$ 1,291.55	3.8%

Total	60,691,613	5,562,109	66,253,722	450,096	9.16%			
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reconciling items:

gas lights	17,954	-	18,186	829
misc revenue	261,301	232	340,610	-
amount to balance to rate calc		79,309	3,692	

9.25% total increase

60,970,868 ↑ Revenues @ Present Rates Exhibit per SS ↑ 5,641,650 Revenue Requirement

\* 66,616,210



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

6. Refer to the Application, Tab 27.
- a. Refer to Schedule 3, lines 12 and 13.
- (1) The pro forma lobbying payroll expense shown on Schedule 3, line 12, does not agree with the information provided in the response to the Commission Staff's First Data Request dated March 19, 2007 ("Staff's First Request"), Item 30. Indicate which amount is correct.
- (2) Provide the workpapers showing the determination of the benefits and taxes loading rate, as stated on Schedule 3, line 13.
- b. Refer to Schedule 3.1.
- (1) Provide the workpapers showing the determination of the annualized salaries and wages and the pro forma capitalized wages and subsidiary allocation, as stated on lines 1 and 2 of Schedule 3.1. The workpapers should indicate whether employees are salaried or hourly and clearly identify employees who were terminated or hired during the test year.
- (2) In the November 10, 2004 Order in Case No. 2004-00067,<sup>1</sup> the Commission found that the payroll adjustment proposed in that case utilized an approach that was not consistent with the Commission's generally used approach for determining payroll expenses for rate-making purposes. Explain how Delta prepared the payroll adjustment proposed in this case and explain why such approach is reasonable.
- (3) If Delta's proposed payroll adjustment did not utilize the approach the Commission described in the November 10, 2004 Order in Case No. 2004-00067, provide a revised payroll expense adjustment based on the Commission's generally used approach. Include all workpapers, calculations, assumptions, and other documentation used to determine the revised adjustment.
- c. Refer to Schedule 4, page 2 of 3. Delta has included in its proposed adjustment depreciation expense on construction work in progress ("CWIP") balances. In the November 10, 2004 Order in Case No. 2004-00067, the Commission rejected the inclusion of depreciation expense on CWIP for rate-making purposes. Explain in detail why the Commission should in this case include depreciation expense on CWIP for rate-making purposes.
- d. Refer to Schedule 5.
- (1) Does Delta's proposed payroll tax adjustment reflect the increase in the Federal Insurance Contribution Act ("FICA") base wage limit that took effect on January 1, 2007? Explain the response.
- (2) Provide a revised Schedule 5 that reflects the effect of the increased FICA base wage limit effective January 1, 2007. Include all workpapers, calculations, and assumptions used to prepare the revision.

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<sup>1</sup> Case No. 2004-00067, Application of Delta Natural Gas Company, Inc. for an Adjustment of Rates, final Order dated November 10, 2004, at 13-15.



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

(3) If Delta prepares a revised payroll adjustment, as previously referenced, provide a corresponding revision to the proposed payroll taxes. Include all workpapers, calculations, and assumptions used to prepare the revised payroll taxes.

e. Refer to Schedule 7.

(1) Provide the calculations used to determine the tax expansion factor.

(2) If the tax expansion factor does not include a component for the PSC Assessment, explain why this component was excluded.

(3) Included on Schedule 7 is the computation of the pro forma effective income tax rate for Delta. Explain the reason for including this calculation and explain how Delta utilized the effective income tax rate in the determination of its revenue requirements.

f. Refer to Schedule 8.

(1) Reconcile the Common Equity per Delta's balance sheet with the test-year-end trial balance provided in the response to the Staff's First Request, Item 10, page 2.

(2) Provide the interest rate for Delta's short-term debt as of June 1, 2007.

**RESPONSE:**

6 a. (1) Both accounts are correct. The Commission Staff's First Data Request dated March 19, 2007, Item 30 gives the test year salary amount of \$8,269.56. The amount shown on Schedule 3, line 12 of the Application, Tab 27, \$8,370, is the pro forma lobbying payroll expense.

Pro forma gross salaries were \$7,051,309, or 1.2% above actual test year gross salaries of \$6,967,327.

1.2% of the lobbying component of test year gross salaries of \$8,270 is \$100. Therefore, we estimated that pro forma lobbying salary expense will be \$8,370.

6 a. (2) See attached.

6 b. (1) See attached Item 6b(1) schedule 1 for determination of annualized salaries and wages and Item 6b(1) schedule 2 for the pro forma capitalized wages and subsidiary allocations.

6 b. (2) Delta performed a detailed, specific identification analysis based on the status of each full-time (salaried) and part-time (hourly) employee and position, in order to determine annualized salaries and wages for the test year. Delta's test year annualized salaries and wages of \$7,051,309:

**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

Includes

- Annualized regular salary, effective December 31, 2006, for each full-time employee/position
- Overtime for each full-time employee/position based on actual overtime hours worked during 2006 and annualized regular salary, effective December 31, 2006.
- Wages for each part-time, including seasonal, employee based on actual 2006 compensation.

Excludes

- Salary, overtime and wages for any employee terminated during 2006 with a position that will not be filled by Delta.
- Known and measurable change in salaries for an overall 3.5% increase to be effective July 1, 2007.

Delta believes that its comprehensive analysis, based on the status of each employee and position, is more (but not totally, because the July 1, 2007 increase has been excluded) reflective of the ongoing level of salaries and wages than a simplistic test-year-end calculation, which ignores the seasonality of its operations.

6 b. (3) Delta has not calculated a proposed salaries and wages adjustment based only on "the level of employees at the end of the test year, priced at the test-year-end level of wages," as described in the November 10, 2004 Order in Case No. 2004-00067, because the result would not be reflective of its normal operations. However, as set forth in the detail analysis of test-year salaries and wages of \$7,051,309 prepared and provided by Delta, that amount would be decreased by \$54,315 if the calculation described above excluded the part time seasonal employees and decreased by \$75,065 if the calculation excluded both the part-time seasonal and the part-time year round employees.

6 c. Although the Commission, in the November 10, 2004 Order for Case No. 2004-00067, rejected the inclusion of depreciation expense on CWIP for rate-making purpose, it also stated: "In the event a utility proposed to recognize new plant additions occurring after test-year end, it might be appropriate to recognize a level of depreciation expense on the new plant additions."

Delta's adjustment for depreciation expense is consistent with the Commission's guidance for allowing this known and measurable change. In addition, the \$38,793 increase in test year depreciation expense, for new plant additions occurring after test-year end, is internally consistent with test year rate base, whereby Delta has included the \$2,275,552 related amount of CWIP in property, plant and equipment and increased accumulated depreciation for the \$38,793 of additional depreciation expense.

**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

6 d. (1) No.

6 d. (2) Schedules 1-9 from the Filing Requirements Tab 27 have been revised and attached here as Item 6d(2).

They include Schedule 5 which has been revised to reflect the effect of the increased FICA base wage limit effective January 1, 2007 as requested in this question. The recalculation of the payroll adjustment resulted in a \$32 decrease in the amount originally proposed.

Schedule 5 has also been revised to include an adjustment for property taxes as discussed in Brown Testimony page 6, line 16. The calculation of pro forma property taxes is shown on schedule 5.1, also attached. This adjustment increases test year taxes other than income taxes by \$25,138.

Schedule 6 has been revised to reduce rate base by \$831,877. In preparing the responses to these questions, we discovered that a reclassification made for SEC reporting purposes to show cost of removal as a regulated liability rather than as accumulated depreciation was inadvertently also made in preparation of the rate case. Cost of removal is not a regulated liability for rate making purposes as we are proposing no changes to our recovery method of cost of removal. The revision to schedule 6 puts cost of removal back with accumulated depreciation where it belongs for ratemaking purposes and consistent with all previous cases. This reduction in rate base reduced our pro forma return by \$73,761 and reduced our revenue deficiency by \$118,893. We have elected not to revise any other schedules prepared reflecting rate base or accumulated depreciation, as this correction does not represent a material change to either.

Schedule 3 was revised to pro forma the \$65,000 one time effect on 1.926.04 Medical Coverage of revising the incurred but not reported reserve during the test year and the \$18,017 of cutoff errors booked to 1.923.01 Legal Expense during the test year as discussed in this Item 17(a)(1) of this request.

Finally, Schedule 7 was revised to include the PSC assessment as a component of the tax expansion factor as pointed out in 6e(2). This change increased the revenue deficiency \$8,368.

Schedule 10 has been added which reconciles the Return and Revenue Deficiency on the revised schedules with the originally filed schedules. It shows that the net effect of these proposed adjustments reduces requested return by \$72,841 and decreases the revenue deficiency \$917.

6 d. (3) Not applicable.

**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

6 e. (1) The tax expansion factor =  $1/(1 - \text{tax rate})$ . The tax rate, as computed on schedule 7.1 of Tab 27 of the Application, is 37.96%.  $1/(1 - .3796) = 1.6118633$ .

6 e. (2) Failing to include a component for the PSC assessment was an oversight. Adding the .001706 PSC assessment rate to the tax expansion factor computed in 6e(1) makes the formula  $1/(1 - .3796 - .001706) = 1.6163079$ . The schedules filed with 6d(2) have been revised to reflect this change.

6 e. (3) Computing the effective income tax rate and comparing it to the statutory income tax rate is a control procedure to help ensure the statutory income tax rate was accurately applied. We included this calculation to aid in such analysis. The difference in the two rates should be the amortization of ITC and excess deferred taxes, which total \$103,100, as detailed on lines 5 and 6 of the schedule. If you divide the \$103,100 of amortization into the \$8,266,406 of pre-tax net income on line 12 of the schedule, you see that the amortizations are projected to be 1.247% of pre-tax net income. If you subtract the 1.247% of amortizations from the 37.96% statutory rate, you get the 36.713% effective tax rate.

6 f. (1) Per trial balance	1.201 Common stock	( 3,267,942)
	1.207 Premiums on common stock	(45,929,039)
	1.214 Capital stock expense	2,643,354
	1.216 Retained earnings	( 1,633,303)
	12/31/06 consolidated net income	<u>( 4,550,017)</u>
	Common equity, per balance sheet	<u>(52,736,947)</u>

6 f. (2) 6.32%

Sponsoring Witness:

John B. Brown

## Employee Benefit and Tax Calculation

LINE NO.		Test Year Cost
	Employee Benefits	
1	Hospitalization, medical and dental insurance	985,273
2	Salary continuation insurance - illness or disability	129,709
3	Employee stock plan - company portion (1% of salary)	-
4	Employee Retirement Plans - defined benefit and defined contribution	1,013,359
5	Employee education	9,031
6	Employee Recreation & Social	7,680
7		<u>2,145,052</u>
8		
9		
10	Payroll Taxes (Excluding bonus)	
11	FICA	391,384
12	Medicare	99,492
13	State Unemployment	13,973
14	Federal Unemployment	9,841
15		<u>514,691</u>
16		
17		
18	Employee Benefit Expense	2,145,052
19	Payroll Taxes	<u>514,691</u>
20		2,659,743
21		
22		
23	Benefit Expense	2,659,743
24	Direct total payroll (excluding bonus)	6,967,327
25		38.2%

EMP NO	SALARIED/HOURLY	NEW HIRE	TERMINATED	ACTUAL HOURS WORKED			ACTUAL SALARIES			TOTAL GROSS SALARIES	Salaries 12/31/2006	Part-time (Seasonal/ Year Round)	Pro Forma Salaries and Wages		Item 6b(1) Schedule 1
				REGULAR	Overtime	01/01/06 - 12/31/06	REGULAR	Overtime	01/01/06 - 12/31/06				Regular	Overtime	
60	SALARIED			2,080.00	55.00	37,200.00	1,477.98	38,677.98	37,700	37,700		37,700	1,495	39,195	
70	SALARIED			2,080.00	72.00	34,750.00	1,781.29	36,531.29	35,300	35,300		35,300	1,833	37,133	
100	SALARIED			2,080.00		71,600.00		71,600.00	73,100	73,100		73,100		73,100	
3378	SALARIED			2,080.00	52.00	29,700.00	1,118.06	30,818.06	30,300	30,300		30,300	1,136	31,436	
3400	SALARIED			2,080.00	165.00	26,550.00	3,137.57	29,687.57	27,100	27,100		27,100	3,224	30,324	
3336	SALARIED			2,080.00	74.00	32,050.00	1,718.77	33,768.77	32,700	32,700		32,700	1,745	34,445	
130	SALARIED			2,080.00	338.00	36,000.00	8,826.61	44,826.61	37,000	37,000		37,000	9,019	46,019	
3469	HOURLY	X	X	496.00		4,464.00		4,464.00			4,464	4,464		4,464	
3331	SALARIED			2,080.00	63.00	29,300.00	1,337.61	30,637.61	29,900	29,900		29,900	1,358	31,258	
140	SALARIED		X	1,250.00		24,758.00		24,758.00							
3464	HOURLY	X	X	388.00		3,492.00		3,492.00			3,492	3,492		3,492	
200	SALARIED			2,080.00		45,800.00		45,800.00	46,600	46,600		46,600		46,600	
210	SALARIED			2,080.00	328.00	36,200.00	8,583.43	44,783.43	36,800	36,800		36,800	8,704	45,504	
280	SALARIED			2,080.00	49.00	38,100.00	1,355.30	39,455.30	38,600	38,600		38,600	1,364	39,964	
290	SALARIED			2,080.00	93.00	33,600.00	2,243.95	35,843.95	34,200	34,200		34,200	2,294	36,494	
320	SALARIED			2,080.00	39.00	35,850.00	1,012.50	36,862.50	36,300	36,300		36,300	1,021	37,321	
3461	SALARIED	X		1,305.00	51.50	19,372.00	1,160.20	20,532.20	31,300	31,300		31,300	1,162	32,462	
400	SALARIED			2,080.00	91.00	34,700.00	2,275.01	36,975.01	35,300	35,300		35,300	2,317	37,617	
405	SALARIED			2,080.00		139,250.00		139,250.00	143,000	143,000		143,000		143,000	
3475	SALARIED	X		784.00	42.00	9,713.00	784.44	10,497.44	25,900	25,900		25,900	784	26,684	
420	SALARIED			2,080.00	39.00	42,500.00	1,200.88	43,700.88	43,200	43,200		43,200	1,215	44,415	
440	SALARIED			2,080.00	31.00	36,300.00	816.26	37,116.26	36,900	36,900		36,900	825	37,725	
3390	SALARIED			2,080.00	42.00	29,300.00	892.59	30,192.59	29,900	29,900		29,900	906	30,806	
3405	SALARIED			2,080.00		24,400.00		24,400.00	24,900	24,900		24,900		24,900	
3367	SALARIED			2,080.00	81.00	26,600.00	1,554.80	28,154.80	27,100	27,100		27,100	1,563	28,663	
450	SALARIED			2,080.00	69.50	39,400.00	1,999.15	41,399.15	40,100	40,100		40,100	2,010	42,110	
3428	HOURLY			855.00		8,550.00		8,550.00			8,550	8,550		8,550	
80	SALARIED			2,080.00		40,500.00		40,500.00	41,100	41,100		41,100		41,100	
3412	HOURLY			856.00		8,560.00		8,560.00			8,560	8,560		8,560	
500	SALARIED			2,080.00		71,200.00		71,200.00	72,400	72,400		72,400		72,400	
518	SALARIED			2,080.00	44.00	27,350.00	877.23	28,227.23	27,800	27,800		27,800	882	28,682	
520	SALARIED			2,080.00		146,400.00		146,400.00	150,000	150,000		150,000		150,000	
585	SALARIED			2,080.00	39.00	29,350.00	829.79	30,179.79	29,900	29,900		29,900	841	30,741	
580	SALARIED			2,080.00		34,600.00		34,600.00	35,100	35,100		35,100		35,100	
590	SALARIED			2,080.00	52.00	33,450.00	1,258.36	34,708.36	34,000	34,000		34,000	1,275	35,275	
600	SALARIED			2,080.00		51,150.00		51,150.00	52,100	52,100		52,100		52,100	
620	SALARIED			2,080.00		34,150.00		34,150.00	34,700	34,700		34,700		34,700	
625	SALARIED		X	567.00		7,423.00		7,423.00							
3398	SALARIED			2,080.00		46,550.00		46,550.00	47,500	47,500		47,500		47,500	
680	SALARIED			2,080.00		32,600.00		32,600.00	33,100	33,100		33,100		33,100	
700	SALARIED			2,080.00		55,600.00		55,600.00	56,600	56,600		56,600		56,600	
720	SALARIED			2,080.00		60,000.00		60,000.00	61,500	61,500		61,500		61,500	
3446	SALARIED			2,080.00	131.50	25,650.00	2,445.85	28,095.85	26,000	26,000		26,000	2,465	28,465	

EMP NO	SALARIED/ HOURLY	NEW HIRE	TERMINATED	ACTUAL HOURS WORKED 01/01/06 - 12/31/06		ACTUAL SALARIES 01/01/06 - 12/31/06		TOTAL GROSS SALARIES	Salaries 12/31/2006	Part-time (Seasonal/ Year Round)	Pro Forma Salaries and Wages		Item 6b(1) Schedule 1
				REGULAR	Overtime	REGULAR	Overtime				Regular	Overtime	
760	SALARIED			2,080.00		63,100.00		63,100.00	64,200		64,200		64,200
3455	SALARIED			2,080.00	79.50	26,588.00	1,520.44	28,108.44	28,500		28,500	1,634	30,134
770	SALARIED			2,080.00	36.00	35,200.00	911.83	36,111.83	36,900		36,900	932	36,832
800	SALARIED			2,080.00	87.00	37,150.00	2,331.27	39,481.27	37,800		37,800	2,372	40,172
820	SALARIED			2,080.00		42,350.00		42,350.00	42,900		42,900		42,900
850	SALARIED			2,080.00		28,850.00		28,850.00	29,400		29,400		29,400
855	SALARIED			2,080.00	85.00	31,900.00	1,970.47	33,870.47	32,500		32,500	1,992	34,492
3349	SALARIED			2,080.00	1.00	23,900.00	17.45	23,917.45	24,200		24,200	17	24,217
880	SALARIED			2,080.00		49,750.00		49,750.00	50,700		50,700		50,700
3471	SALARIED	X		1,008.00		11,873.00		11,873.00	24,500		24,500		24,500
3403	SALARIED	X		472.00		5,838.00		5,838.00					
965	SALARIED		X	2,080.00	231.00	28,350.00	4,734.17	33,084.17	28,900		28,900	4,814	33,714
980	SALARIED			2,080.00		36,900.00		36,900.00	37,500		37,500		37,500
1000	SALARIED			2,080.00	44.00	35,700.00	1,128.44	36,828.44	36,300		36,300	1,152	37,452
1020	SALARIED			2,080.00	83.00	38,950.00	2,329.78	41,279.78	39,700		39,700	2,376	42,076
1040	SALARIED			2,080.00	21.00	38,350.00	572.46	38,922.46	38,900		38,900	589	39,489
3470	HOURLY	X	X	612.00	3.00	5,508.00	40.50	5,548.50		5,508	5,508		5,508
1060	SALARIED			2,080.00		38,750.00		38,750.00	39,500		39,500		39,500
1080	SALARIED			2,080.00		54,600.00		54,600.00	55,500		55,500		55,500
3417	SALARIED		X	434.00		11,041.00		11,041.00					
1120	SALARIED			2,080.00	87.00	33,400.00	2,090.81	35,490.81	34,000		34,000	2,133	36,133
1140	SALARIED			2,080.00	155.00	28,350.00	3,174.03	31,524.03	28,900		28,900	3,230	32,130
3399	SALARIED			2,080.00	172.00	32,250.00	3,990.84	36,240.84	32,900		32,900	4,081	36,981
3415	SALARIED		X	799.00	36.00	12,270.00	810.00	13,080.00					
1220	SALARIED			2,080.00	81.00	43,150.00	2,508.06	45,658.06	43,900		43,900	2,564	46,464
3451	SALARIED			2,080.00	50.00	25,700.00	935.90	26,635.90	26,100		26,100	941	27,041
1240	SALARIED			2,080.00		150,500.00		150,500.00	154,000		154,000		154,000
1260	SALARIED			2,080.00	63.00	35,550.00	1,822.63	37,372.63	36,100		36,100	1,640	37,740
1320	SALARIED			2,080.00		33,050.00		33,050.00	33,800		33,800		33,800
3443	SALARIED			2,080.00	39.00	25,900.00	742.71	26,642.71	26,500		26,500	745	27,245
1340	SALARIED			2,080.00		77,000.00		77,000.00	78,000		78,000		78,000
1360	SALARIED			2,080.00		164,850.00		164,850.00	169,000		169,000		169,000
1420	SALARIED		X	1,320.00		44,492.00		44,492.00					
1480	SALARIED			2,080.00	11.00	35,550.00	279.23	35,829.23	36,100		36,100	286	36,386
1485	SALARIED		X	2,080.00	95.00	28,050.00	1,918.06	29,968.06	28,600		28,600	1,959	30,559
3463	HOURLY	X	X	855.00	4.00	7,695.00	54.00	7,749.00		7,695	7,695		7,695
3457	SALARIED			2,020.00	122.00	30,950.00	2,741.66	33,691.66	31,300		31,300	2,754	34,054
3401	SALARIED		X	2,086.00		24,823.00		24,823.00	25,300		25,300		25,300
3324	SALARIED			2,080.00	55.50	34,400.00	1,390.40	35,790.40	35,000		35,000	1,401	36,401
1540	SALARIED		X	1,951.00	53.00	34,932.00	1,416.83	36,348.83					
1560	SALARIED			2,080.00		329,500.00		329,500.00	337,000		337,000		337,000
1580	SALARIED			2,080.00		37,150.00		37,150.00	37,900		37,900		37,900
3344	SALARIED			2,080.00	159.50	34,500.00	3,991.53	38,491.53	35,100		35,100	4,037	39,137
3459	SALARIED	X		1,560.00		26,550.00		26,550.00	35,600		35,600		35,600

EMP NO	SALARIED/HOURLY	NEW HIRE	TERMINATED	ACTUAL HOURS WORKED		ACTUAL SALARIES		TOTAL GROSS SALARIES	Salaries 12/31/2006	Part-time (Seasonal/ Year Round)	Pro Forma Salaries and Wages		Item 6b(1) Schedule 1	
				01/01/06 - 12/31/06		01/01/06 - 12/31/06					Regular	Overtime		Total
				REGULAR	Overtime	REGULAR	Overtime							
3382	SALARIED			2,080.00	87.00	29,900.00	1,881.57	31,781.57	30,500	1,914	30,500	1,914	32,414	
1590	SALARIED			2,080.00	125.00	38,000.00	3,446.62	41,446.62	38,600	3,480	38,600	3,480	42,080	
1600	SALARIED			2,080.00		63,600.00		63,600.00	67,000		67,000		67,000	
1620	SALARIED			2,080.00		39,600.00		39,600.00	40,700		40,700		40,700	
1680	SALARIED			2,080.00	20.00	34,150.00	487.77	34,637.77	34,700		34,700	500	35,200	
3433	HOURLY	X		636.00		6,360.00		6,360.00		6,360			6,360	
1750	SALARIED		X	2,080.00		43,367.00		43,367.00	45,800		45,800		45,800	
3456	SALARIED			1,789.00		19,514.00		19,514.00	23,600		23,600		23,600	
1760	SALARIED			2,080.00	8.00	37,088.00	209.42	37,297.42	37,900	219	37,900	219	38,119	
1780	SALARIED			2,080.00	75.00	39,150.00	2,116.97	41,266.97	39,800	2,153	39,800	2,153	41,953	
3411	SALARIED			2,080.00		49,600.00		49,600.00	50,200		50,200		50,200	
3460	HOURLY	X	X	24.00		216.00		216.00						
1843	SALARIED		X	759.00		12,891.00		12,891.00						
3397	SALARIED			2,080.00	55.50	28,950.00	1,162.68	30,112.68	29,400	1,177	29,400	1,177	30,577	
1855	SALARIED			2,080.00	122.00	33,800.00	2,947.74	36,747.74	34,400	3,026	34,400	3,026	37,426	
1860	SALARIED			2,080.00	45.00	29,150.00	947.57	30,097.57	29,600	961	29,600	961	30,561	
3434	HOURLY	X	X	321.00		3,210.00		3,210.00		3,210			3,210	
3474	SALARIED	X		784.00		14,213.00		14,213.00	37,900		37,900		37,900	
1895	SALARIED			2,080.00		37,650.00		37,650.00	38,300		38,300		38,300	
3462	SALARIED	X	X	344.00	20.00	4,144.00	367.50	4,511.50						
1910	SALARIED			2,080.00		60,650.00		60,650.00	61,700		61,700		61,700	
1925	SALARIED			2,080.00		54,800.00		54,800.00	55,800		55,800		55,800	
1940	SALARIED			2,080.00	13.00	44,300.00	419.20	44,719.20	44,900		44,900		44,900	
1950	SALARIED			2,080.00	78.00	34,300.00	1,929.71	36,229.71	34,900	1,963	34,900	1,963	36,863	
1970	SALARIED			2,080.00		71,250.00		71,250.00	73,000		73,000		73,000	
2005	SALARIED			2,017.00	75.50	33,450.00	1,822.89	35,272.89	34,100	1,857	34,100	1,857	35,957	
2010	SALARIED			2,080.00		44,550.00		44,550.00	45,300		45,300		45,300	
2013	SALARIED			2,052.00	79.00	33,502.00	1,949.59	35,451.59	34,600	1,971	34,600	1,971	36,571	
3396	SALARIED		X	1,006.00		17,888.00		17,888.00						
3472	HOURLY	X	X	279.00		2,511.00		2,511.00		2,511			2,511	
3416	SALARIED			1,920.00	83.00	23,786.00	1,533.11	25,319.11	26,100	1,562	26,100	1,562	27,662	
3361	SALARIED			2,080.00	34.00	29,700.00	733.99	30,433.99	30,200	740	30,200	740	30,940	
2030	SALARIED			2,080.00		52,000.00		52,000.00	53,000		53,000		53,000	
3467	HOURLY	X	X	807.00		7,263.00		7,263.00		7,263			7,263	
3427	SALARIED			2,080.00	86.50	26,300.00	1,628.16	27,928.16	28,500	1,778	28,500	1,778	30,278	
3477	SALARIED	X		120.00	14.50	1,906.00	327.29	2,233.29	31,300	327	31,300	327	31,627	
3363	SALARIED			2,080.00		37,650.00		37,650.00	38,300		38,300		38,300	
2160	SALARIED			2,080.00	64.00	35,850.00	1,653.80	37,503.80	36,400	1,680	36,400	1,680	38,080	
3372	SALARIED			2,080.00	55.00	27,550.00	1,103.44	28,653.44	28,100	1,115	28,100	1,115	29,215	
3419	SALARIED			2,080.00	55.00	28,400.00	1,138.54	29,538.54	29,000	1,150	29,000	1,150	30,150	
2220	SALARIED			2,080.00		62,450.00		62,450.00	63,500		63,500		63,500	
2240	SALARIED			2,080.00		51,550.00		51,550.00	52,300		52,300		52,300	
3373	SALARIED			2,080.00	77.00	27,300.00	1,525.68	28,825.68	27,800	1,544	27,800	1,544	29,344	
2280	SALARIED			2,080.00	165.00	39,000.00	4,675.87	43,675.87	40,000	4,759	40,000	4,759	44,759	



EMP NO	SALARIED/HOURLY	NEW HIRE	TERMINATED	ACTUAL HOURS WORKED		ACTUAL SALARIES		TOTAL GROSS SALARIES	Salaries 12/31/2006	Part-time (Seasonal/Year Round)	Pro Forma Salaries and Wages		Item 6b(1) Schedule 1
				REGULAR	Overtime	REGULAR	Overtime				Regular	Overtime	
3488	SALARIED	X		1,010.00	90.00	11,548.00	1,618.80	13,166.80	25,900		25,900	1,681	27,581
3393	SALARIED			2,080.00		24,450.00		24,450.00	24,900		24,900		24,900
2290	SALARIED			2,080.00	115.50	31,700.00	2,620.58	34,320.58	32,300		32,300	2,690	34,990
2340	SALARIED			2,080.00		70,200.00		70,200.00	71,400		71,400		71,400
3466	SALARIED	X		1,107.00	1.00	16,477.00	22.07	16,499.07	30,600		30,600	22	30,622
3420	SALARIED			2,008.00	97.00	31,150.00	2,179.34	33,329.34	31,700		31,700	2,217	33,917
2360	SALARIED			2,080.00	107.00	44,850.00	3,467.27	48,317.27	45,600		45,600	3,519	49,119
2420	SALARIED			2,080.00		71,600.00		71,600.00	73,100		73,100		73,100
3301	SALARIED		X	1,196.00		20,320.00		20,320.00					
3414	SALARIED			2,080.00	40.50	29,900.00	888.23	30,788.23	30,500		30,500	891	31,391
3452	SALARIED		X	200.00	16.50	2,238.00	301.05	2,539.05					
2450	SALARIED			1,944.00		41,762.00		41,762.00	45,800		45,800		45,800
2460	SALARIED			2,080.00		89,100.00		89,100.00	91,300		91,300		91,300
3448	HOURLY	X		461.00		4,610.00		4,610.00		4,610	4,610		4,610
2480	SALARIED			2,080.00		43,300.00		43,300.00	44,500		44,500		44,500
3358	SALARIED			2,080.00	69.00	29,750.00	1,484.70	31,234.70	30,300		30,300	1,508	31,808
3458	SALARIED	X		1,427.00	69.00	21,033.00	1,539.02	22,572.02	31,300		31,300	1,557	32,857
2550	SALARIED			2,080.00	135.00	45,600.00	4,489.53	50,089.53	46,400		46,400	4,517	50,917
2560	SALARIED		X	853.00		13,398.00		13,398.00					
3365	SALARIED			2,032.00	120.00	34,367.00	2,860.84	37,227.84	37,900		37,900	3,280	41,180
3309	SALARIED			2,080.00	55.00	34,350.00	1,386.82	35,736.82	35,100		35,100	1,392	36,492
2615	SALARIED			2,080.00	69.50	31,850.00	1,601.22	33,451.22	32,400		32,400	1,624	34,024
3454	SALARIED			2,080.00	37.50	25,700.00	704.09	26,404.09	26,100		26,100	706	26,806
2675	SALARIED			2,080.00		28,050.00		28,050.00	28,600		28,600		28,600
2720	SALARIED			2,080.00	65.00	36,750.00	1,726.82	38,476.82	37,400		37,400	1,753	39,153
3476	HOURLY	X		364.00		3,640.00		3,640.00		3,640	3,640		3,640
2735	SALARIED			2,080.00		48,100.00		48,100.00	49,100		49,100		49,100
2782	SALARIED			2,080.00		44,100.00		44,100.00	45,100		45,100		45,100
1130	SALARIED			2,080.00		36,200.00		36,200.00	36,800		36,800		36,800
2800	SALARIED			2,080.00	80.00	33,750.00	1,962.95	35,712.95	34,300		34,300	1,979	36,279
2820	SALARIED			2,080.00		53,800.00		53,800.00	54,800		54,800		54,800
2840	SALARIED			2,080.00		43,750.00		43,750.00	44,400		44,400		44,400
2860	SALARIED			2,080.00		35,200.00		35,200.00	35,700		35,700		35,700
2865	SALARIED			2,080.00	67.00	30,150.00	1,459.94	31,609.94	30,700		30,700	1,483	32,183
2870	SALARIED			2,080.00	42.00	31,500.00	961.84	32,461.84	32,100		32,100	972	33,072
2880	SALARIED			2,080.00	48.00	37,200.00	1,297.22	38,497.22	37,800		37,800	1,308	39,108
2920	SALARIED			2,080.00		30,400.00		30,400.00	30,900		30,900		30,900
2940	SALARIED			2,080.00		35,700.00		35,700.00	36,200		36,200		36,200
2960	SALARIED			2,080.00	74.00	39,450.00	2,121.86	41,571.86	40,000		40,000	2,135	42,135
2980	SALARIED			2,080.00		53,633.00		53,633.00	55,300		55,300		55,300
2985	SALARIED			2,080.00	70.00	32,750.00	1,651.61	34,401.61	33,300		33,300	1,681	34,981
3000	SALARIED			2,080.00		33,900.00		33,900.00	34,500		34,500		34,500
3060	SALARIED			2,080.00	10.00	46,600.00	338.07	46,938.07	47,300		47,300	341	47,641
3473	HOURLY	X		388.00		3,492.00		3,492.00		3,492	3,492		3,492

EMP NO	SALARIED/ HOURLY	NEW HIRE	TERMINATED	ACTUAL HOURS WORKED 01/01/06 - 12/31/06		ACTUAL SALARIES 01/01/06 - 12/31/06		TOTAL GROSS SALARIES	Salaries 12/31/2006	Part-time (Seasonal/ Year Round)	Pro Forma Salaries and Wages		Item 6b(1) Schedule 1
				REGULAR	Overtime	REGULAR	Overtime				Regular	Overtime	
3374	SALARIED			2,080.00		41,250.00	41,250.00	42,000			42,000		42,000
3338	SALARIED			2,080.00		73,100.00	73,100.00	74,700			74,700		74,700
3442	SALARIED			2,080.00	40.00	28,250.00	29,066.84	28,700			28,700	828	29,528
3160	SALARIED			2,080.00		32,600.00	32,600.00	33,100			33,100		33,100
3447	HOURLY	X	X	571.00	3.00	5,710.00	5,755.00			5,710	5,710		5,710
3465	SALARIED	X		1,087.00		16,575.00	16,575.00	30,600			30,600		30,600
3260	SALARIED			2,080.00	110.00	36,900.00	39,806.73	37,500			37,500	2,975	40,475
3323	SALARIED			2,080.00		37,500.00	37,500.00	38,000			38,000		38,000
				330,004.00	6,963.50	6,800,954.00	6,967,326.68	6,810,200		75,065	6,885,265	166,044	7,051,309

## Delta Natural Gas Co., Inc. Pro Forma Capitalized Wages and Subsidiary Allocation

Item 6 b. (1)  
Schedule 2

	2006 Calendar Actual	Remove Bonus	Recompute Field Vac and Sick (A)	Recompute Admin Salary to Subs (B)	Increase Factor (C)	Pro Forma
Direct payroll charges						
Construction	725,816				8,749	734,565
Other accounts						
Merchandising	1,115				13	1,128
Miscellaneous non operating	2,556				31	2,587
Subsidiaries	6,674				80	6,754
Total other accounts	10,345					
Other charges						
Construction	811,009				9,776	820,785
Other accounts						
Lobbying	8,270				100	8,370
Miscellaneous non operating			542		7	549
Subsidiaries						
Storage allocation	25,606				309	25,915
Admin time study	24,782		1,029	13,389	473	39,673
Bonus	513,577	(513,577)				
Total subsidiaries	563,965					
Total other accounts	572,235					
Rounding						(17)
Total pro forma capitalized wages and subsidiary allocation						<u>1,640,308</u>

		Non-reg	Subs
(A) Vacation and sick allocated to non-reg	Field - vacation and sick	502,106	
		<u>0.11%</u>	<u>0.20%</u>
		<u>542</u>	<u>1,029</u>
(B) Recompute salaries allocated to subs based on updated time study	Admin payroll	2,482,184	
	Charged to construction	<u>(698,487)</u>	
		1,783,697	<u>2.14%</u>
			38,171
	Less actual		<u>(24,782)</u>
	Increase		<u>13,389</u>
(C) Pro Forma increase factor	Pro Forma gross salaries		7,051,309
	Actual gross salaries		<u>6,967,327</u>
			<u>1.21%</u>

DELTA NATURAL GAS CO., INC.  
Revenue Requirements and Deficiency  
Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
Schedule 1

<u>Line Number</u>		<u>Schedule</u>	<u>Amount</u>
1	Cost of gas	2	35,207,784
2	Operations & maintenance expense	3	11,613,161
3	Depreciation expense	4	4,527,707
4	Taxes other than income taxes	5	1,796,243
5	Return	6	10,423,457
6	Income tax	7	<u>3,043,196</u>
7	Total revenue requirements		66,611,548
8	Revenues at present rates	2	<u>(60,970,868)</u>
9	Revenue deficiency		<u><u>5,640,680</u></u>
10	Percent increase		<u>9.25%</u>

DELTA NATURAL GAS CO., INC.  
Summary of Revenues and Cost of Gas at Present Rates  
Test Year Ended 12/31/06

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Actual Billed Revenue	Elimination of Gas Cost Adjustment	Correction	Net Revenue Before Temperature Adjustment	Temperature Adjustment	GCR at Current Rates	Adjusted Billings at Current Rates	Proposed Increase in Revenue		
			(Column (1) + (2) + (3))	(See Seelye Exhibit 9)	(Column (4) + (5) + (6))				(%)
<b>REVENUE</b>									
Residential	34,527,341	(22,936,301)		11,591,040	(53,005)	19,333,683	30,871,718	3,845,405	12.46%
Small Non-Residential GS	10,269,885	(7,026,753)		3,243,132	(11,271)	5,940,440	9,172,300	471,298	5.14%
Large Non-Residential GS	13,254,779	(9,926,896)		3,327,883	89,258	8,384,984	11,802,126	563,300	4.77%
Large Non-Residential GS - Commercial	1,721,229	(1,380,929)		340,300	13,389	1,156,453	1,510,142	57,756	3.82%
Large Non-Residential GS - Industrial	14,976,008	(11,307,825)		3,668,183	102,647	9,541,438	13,312,267	621,056	4.67%
Total Large Non-Residential GS									
Interruptible									
Interruptible - Commercial	39,289	(33,432)		5,857	314	28,759	34,930	-	
Interruptible - Industrial	484,019	(410,922)	(3,992)	69,105	1,568	350,445	421,119	-	
Total Interruptible	523,308	(444,354)	(3,992)	74,963	1,882	379,205	456,049	-	0.00%
Unmetered Gas Lights									
Residential	9,737	(7,262)		2,475		6,205	8,680	(1)	
Commercial	4,291	(3,267)		1,024		2,813	3,838	97	
Small Commercial	6,008	(4,574)		1,434		4,001	5,436	136	
Unmetered Gas Lights	20,037	(15,102)		4,934		13,020	17,954	232	1.29%
Total Retail	60,316,579	(41,730,336)	(3,992)	18,582,251	40,253	35,207,784	53,830,288	4,937,991	
Special Contracts	608,063	-		608,063	-	-	608,063	-	
Small Non-Residential GS	147,218	-		147,218	5,207	-	152,425	17,885	
Large Non-Residential GS	2,016,375	-		2,016,375	60,993	-	2,077,368	509,063	
Residential	6,377	-		6,377	-	-	6,377	1,826	
Interruptible	1,550,100	-		1,550,100	-	-	1,550,100	-	
On System Transportation	4,328,133	-		4,328,133	66,200	-	4,394,333	528,775	12.03%
Off System Transportation	2,484,947	-		2,484,947	-	-	2,484,947	95,575	3.85%
Total Transportation	6,813,080	-		6,813,080	66,200	-	6,879,280	624,350	9.08%
Miscellaneous Revenue	261,301	-		261,301			261,301	79,309	30.35%
Total Operating Revenue	67,390,960	(41,730,336)	(3,992)	25,656,632	106,453	35,207,784	60,970,869	5,641,650	9.25%

DELTA NATURAL GAS CO., INC.  
Operations and Maintenance Expenses  
Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
Schedule 3

Line Number		Schedule	Amount
1	Adjustments		
2	Payroll expense	3.1	49,485
3	Rate case expense	3.2	33,700
4	A/C 1.913 Advertising expense		(2,264)
5	A/C 1.930.12 Lobbying expense		(23,281)
6	Lobbying benefits and taxes, calculated below		(3,206)
7	Public and community relations, calculated below		(22,664)
8	A/C 1.930.04 Marketing		(3,973)
9	A/C 1.926.04 Medical coverage, see item 17 (a) (1)		65,000
10	A/C 1.923.01 Legal expense, see item 17 (a) (1)		<u>18,017</u>
11	Total adjustments		110,814
12	Per books		<u>11,502,347</u>
13	O&M Adjusted		<u><u>11,613,161</u></u>

Lobbying Benefits and Taxes Adjustment

Line Number		Amount
14	Pro forma lobbying payroll expense	8,370
15	Benefits and taxes loading rate	<u>38.3%</u>
16	Lobbying benefits and taxes	<u><u>3,206</u></u>

Public and Community Relations Adjustment

Line Number		Amount
17	A/C 1.930.10 Public and community relations	52,664
18	Contribution to Energy Assistance Program per Order 2005-00464	<u>30,000</u>
19	Public and community relations adjustment	<u><u>22,664</u></u>

DELTA NATURAL GAS COMPANY, INC.  
Payroll Expense Adjustment  
Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
Schedule 3.1

<u>Line Number</u>		<u>Amount</u>
1	Annualized salaries and wages	7,051,309
2	Pro forma capitalized wages and subsidiary allocation	<u>1,640,308</u>
3	Pro forma salary and wage expense	5,411,001
4	Actual 2006 test year salary and wage expense	<u>5,361,516</u>
5	Pro forma payroll adjustment	<u>49,485</u>

DELTA NATURAL GAS COMPANY, INC.  
Rate Case Expense Adjustment  
Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
Schedule 3.2

<u>Line Number</u>		<u>Amount</u>
1	Estimate of expenses for Case No. 2007-00089 (2004-00067 actual)	267,098
2	Unamortized expenses from Case No. 2004-00067, calculated below	<u>53,598</u>
3	Total expenses to be amortized	<u>320,696</u>
4	Annual projected expenses (based on 3 year amortization period)	106,899
5	Amount of amortization in test year (6,100 monthly amortization x 12)	<u>73,200</u>
6	Adjustment amount	<u><u>33,699</u></u>

Unamortized Expenses from Case No. 2004-00067

<u>Line Number</u>		<u>Amount</u>
7	Balance at 12/31/06	108,498
8	Monthly amortization	6,100
9	Estimated # of months prior to 2007-00089 rates effective	<u>9</u>
		<u>54,900</u>
10	Balance at 9/30/07	<u><u>53,598</u></u>



## DELTA NATURAL GAS CO., INC.

Depreciation Expense  
Test Year Ended 12/31/06

PSC 2 Item 6 d (2)

Schedule 4

Page 1 of 3

<u>LINE</u> <u>NUMBER</u>	<u>ACCT</u> <u>NO</u>	<u>DESCRIPTION</u>	<u>PLANT</u> <u>12/31/2006</u>	<u>DEPR</u> <u>RATE</u>	<u>DEPR</u> <u>EXPENSE</u>
1	301	Organization	53,151	0.00%	0
2	302	Franchise & Consent	-	0.00%	0
3		Sub Total	<u>53,151</u>		<u>0</u>
PRODUCTION					
4	304	Land & Rights		0.00%	0
5	305	Structures & Improvements		2.20%	0
6	325	Right of Ways	75,987	3.00%	2,280
7	327	Comp Stations Structures	42,950	3.00%	1,289
8	331	Well Equipment	7,795	4.00%	0
9	332	Field Lines	1,914,741	2.25%	43,082
10	333	Compressor Station Equipment	817,962	4.00%	32,718
11	334	Measuring & Regulator Stations	136,937	2.72%	3,725
12		Sub Total	<u>2,996,372</u>		<u>83,094</u>
STORAGE & PROCESSING					
13	35001	Storage Land	14,142	0.00%	0
14	35002	Storage Right of Way	177,425	0.00%	0
15	35005	Gas Rights Well	1,495	0.00%	0
16	35006	Gas Rights Storage		5.00%	0
17	351	Structures and Improvements	294,116	2.48%	7,294
18	352	Storage Wells	360,583	2.19%	7,897
19	35201	Storage Rights	860,396	1.85%	15,917
20	35202	Storage Reservoirs	1,881,731	1.78%	33,495
21	35203	Non-Recoverable Natural Gas	294,307	1.75%	5,150
22	353	Storage Lines	5,091,297	2.44%	124,228
23	354	Storage Compressor Station Equipment	2,419,643	1.90%	45,973
24	355	Storage Measuring & Regulator Equipment	363,662	2.41%	8,764
25	356	Purification Equipment	326,326	2.02%	6,592
26	357	Storage Other Equipment	47,209	0.53%	250
27		Sub Total	<u>12,132,332</u>		<u>255,560</u>
TRANSMISSION					
28	3651	Land and Rights	56,999	0.00%	0
29	3652	Rights of Way	1,212,507	0.00%	0
30	3653	Land Rights CVPL	163,626	2.50%	4,091
31	366	Structures and Improvements	182,239	2.00%	3,645
32	367	Transmission Mains	41,447,022	2.24%	928,413
33	368	Compressor Station Equipment	2,463,406	2.00%	49,268
34	369	Measuring & Regulator Station Equipment	2,665,648	3.14%	83,701
35	371	Other Equipment	579,896	2.00%	11,598
36		Sub Total	<u>48,771,343</u>		<u>1,080,716</u>

DELTA NATURAL GAS CO., INC.  
 Depreciation Expense  
 Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
 Schedule 4  
 Page 2 of 3

<u>LINE</u> <u>NUMBER</u>	<u>ACCT</u> <u>NO</u>	<u>DESCRIPTION</u>	<u>PLANT</u> <u>12/31/2006</u>	<u>DEPR</u> <u>RATE</u>	<u>DEPR</u> <u>EXPENSE</u>
DISTRIBUTION					
1	374	Distribution Rights of Way	258,985	0.00%	0
2	37401	Distribution Land	63,206	0.00%	0
3	375	Structures & Improvements	113,715	2.67%	3,036
4	376	Distribution Mains	61,423,134	2.50%	1,535,578
5	378	Measuring & Regulator Station - General	1,356,370	3.27%	44,353
6	379	Measuring & Regulator Station - City Gate	480,352	3.19%	15,323
7	380	Services	12,658,475	2.50%	316,462
8	381	Meters	8,917,576	2.28%	203,321
9	382	Meter and Regulator Installation	3,145,615	4.50%	141,553
10	383	House Regulators	3,093,300	4.13%	127,753
11	385	Industrial Meter Sets	1,530,217	2.40%	36,725
12		Sub Total	<u>93,040,945</u>		<u>2,424,104</u>
GENERAL					
13	389	Land and Rights	1,038,741	0.00%	0
14	390	Structures and Improvements	5,452,189	2.00%	109,044
15	391	Office Furniture and Equipment	135,672	1.00%	1,357
16	392	Autos and Trucks	3,868,757	8.14%	314,917
17	393	Stores Equipment	36,011	2.00%	720
18	394	Tools and Work Equipment	629,382	4.00%	25,175
19	39401	Comp NG Stat and Equipment	283,352	0.00%	0
20	395	Laboratory Equipment	215,820	5.00%	10,791
21	396	Power Operated Equipment	2,779,542	2.00%	55,591
22	397	Communication Equipment	443,788	5.00%	22,189
23	398	Miscellaneous Equipment	54,238	2.00%	1,085
24	3991	Other Tangible Equipment	638,509	4.00%	25,540
25	3992	Computer Software	2,525,991	10.00%	252,599
26	3993	Computer Hardware	937,029	10.00%	93,703
27	399031	Computerized Office Equipment	255,272	10.00%	25,527
28		Sub Total	<u>19,294,293</u>		<u>938,238</u>
29		TOTAL A/C 101	<u>176,288,436</u>		<u>4,781,712</u>
CWIP					
30	368	525528	1,480,882	2.00%	29,618
31	369		175,071	3.14%	5,497
32	371	525506	3,463	2.00%	69
33	376		112,282	2.50%	2,807
34	381	255529	7,843	2.28%	179
35	392	530025	525	8.14%	43
36	39902	63002	5,800	10.00%	580
37	Overhead	53010	489,686		
38		Total CWIP	<u>2,275,552</u>		<u>38,793</u>

DELTA NATURAL GAS CO., INC.  
 Depreciation Expense  
 Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
 Schedule 4  
 Page 3 of 3

<u>LINE</u> <u>NUMBER</u>	<u>ACCT</u> <u>NO</u>	<u>DESCRIPTION</u>	<u>PLANT</u> <u>12/31/2006</u>	<u>DEPR</u> <u>RATE</u>	<u>DEPR</u> <u>EXPENSE</u>
ACQUISITION ADJUSTMENT					
1	1.114	Tranex	(1,045,704)		(58,800)
2	1.114.01	Mt. Olivet	464,945		46,800
3		Total Acquisition Adjustment	<u>(580,759)</u>		<u>(12,000)</u>
4	1.117	Gas Stored Underground	<u>4,208,069</u>		
5					
6		Total Utility Plant In Service	182,191,298		4,808,505
ASSET RETIREMENT OBLIGATION					
7	1.376.01	Distribution Mains	210,849		
8	1.380.01	Distribution Services	138,932		
9		Excluded from plant accounts above	<u>74,634</u>		
10		Reconciled Total	182,615,713		
11		Per Delta Balance Sheet	<u>182,615,711</u>		
12		Difference	<u>2</u>		
TRANSPORTATION CLEARING					
13		Transportation Equipment			(242,400)
14		Power Operated Equipment			<u>(38,400)</u>
15		Pro Forma Depreciation Expense			4,527,705
16		Per Delta Income Statement			<u>4,234,739</u>
17		Depreciation Expense Adjustment			<u>292,966</u>

DELTA NATURAL GAS CO., INC.  
Taxes Other Than Income Taxes  
Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
Schedule 5

Line  
Number

<b>Payroll tax adjustment</b>		<u>FICA</u>	<u>Medicare</u>	<u>FUTA</u>	<u>SUTA</u>
1	Tax base (pro forma)	6,585,809	7,051,309	1,155,997	1,313,955
2	Less test year deductions	<u>(177,181)</u>	<u>(177,181)</u>	_____	_____
3	Tax base after deductions	6,408,628	6,874,128	1,155,997	1,313,955
4	Applicable rate	<u>6.20%</u>	<u>1.45%</u>	<u>0.80%</u>	<u>1.00%</u>
5	Pro forma payroll tax increase	<u>397,335</u>	<u>99,675</u>	<u>9,248</u>	<u>13,140</u>
6	Total pro forma payroll taxes				519,397
7	Payroll taxes (a/c 1.408.03 excluding bonus)				<u>514,691</u>
8	Total payroll tax adjustment				4,706
9	Ratio of salaries and wages charged to expense to total wages				<u>77%</u>
10	Payroll tax adjustment applicable to expense				<u>3,624</u>
<b>Property tax adjustment</b>				<u>Schedule</u>	
11	Pro forma property taxes			5.1	1,246,278
12	Property taxes (a/c 1.408.02)				<u>1,221,140</u>
13	Property tax adjustment				<u>25,138</u>
14	<b>Total adjustments to taxes other than income taxes</b>				<b>28,762</b>
15	<b>Taxes other than income taxes, per books</b>				<b><u>1,767,481</u></b>
16	<b>Taxes other than income taxes adjusted</b>				<b><u>1,796,243</u></b>



DELTA NATURAL GAS CO., INC.  
 Computation of Property Taxes based on 12/31/06 Values  
 Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
 Schedule 5.1  
 Page 1 of 2

	Tax District	12/31/06 Values	Tax Rate per \$100 Last Paid	Calculated Tax
COUNTY	BATH	2,988,857	0.7325	21,893
	BELL (1)	30,748,862	0.2602	79,997
	BOURBON	247,440	0.7165	1,773
	CLARK	3,554,554	0.6318	22,459
	CLAY	10,319,859	0.6895	71,150
	ESTILL	2,661,126	0.8645	23,007
	FAYETTE	950,003	0.7170	6,811
	FLEMING	3,348	0.6954	23
	GARRARD	381,984	0.9429	3,602
	JACKSON	1,638,134	0.8010	13,122
	JESSAMINE	11,149,031	0.7616	84,910
	KNOX (1)	17,147,316	0.3011	51,636
	LAUREL	11,880,889	0.6506	77,298
	LEE	1,400,874	0.8775	12,293
	LESLIE	8,809	0.8905	78
	MADISON (1)	14,125,348	0.2543	35,916
	MASON	85,426	0.7816	668
	MENIFEE	686,417	0.7129	4,893
	MONTGOMERY	1,282,985	0.7988	10,249
	POWELL	3,940,020	0.5323	20,971
ROBERTSON	275,870	0.8186	2,258	
ROWAN	2,612,405	0.5842	15,263	
WHITLEY (1)	<u>13,115,747</u>	0.2381	<u>31,234</u>	
	TOTAL	<u>131,205,304</u>		<u>591,505</u>
CITY	BARBOURVILLE *	1,906,403	0.6730	12,830
	BEATTYVILLE	347,946	0.3000	1,044
	BEREA (1) *	3,539,776	0.0300	1,062
	CLAY CITY	484,060	0.0962	465
	CORBIN *	4,053,188	0.7715	31,272
	FRENCHBURG	330,951	0.0600	199
	LAKEVIEW HEIGHTS	24,711	0.0900	22
	LONDON	2,431,607	0.0960	2,334
	MANCHESTER	814,278	0.3430	2,793
	MIDDLESBORO (1) *	2,733,407	0.1044	2,854
	MT OLIVET	63,471	0.3093	196
	NICHOLASVILLE	7,022,164	0.1711	12,016
	NORTH MIDDLETOWN	98,720	0.1800	178
OWINGSVILLE	1,206,236	0.2156	2,601	

DELTA NATURAL GAS CO., INC.  
 Computation of Property Taxes based on 12/31/06 Values  
 Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
 Schedule 5.1  
 Page 2 of 2

Tax District	12/31/06 Values	Tax Rate per \$100 Last Paid	Calculated Tax
PINEVILLE (1)	442,633	0.3150	1,394
RICHMOND	450,569	0.1499	675
SALT LICK	447,896	0.6908	3,094
SHARPSBURG	147,923	0.2538	375
STANTON	1,213,708	0.0282	342
WILLIAMSBURG (1)	2,142,647	0.2442	5,232
WILMORE	1,155,137	0.2832	3,271
TOTAL	<u>31,057,431</u>		<u>84,250</u>

\* = INDEPENDENT SCHOOL DISTRICT

(1) SCHOOL DISTRICTS WITH SEPARATE BILLING OR VALUE

STATE OF KENTUCKY	<u>131,205,304</u>	0.1708	<u>224,099</u>
BEREA	3,539,776	0.7430	26,301
MIDDLESBORO	2,733,407	0.4810	13,148
PINEVILLE	442,633	0.4880	2,160
BELL CO.	27,569,620	0.4350	119,928
KNOX CO.	14,680,773	0.4090	60,044
MADISON CO.	10,615,241	0.8110	86,089
WHITLEY CO.	7,453,810	0.3968	29,576
WILLIAMSBURG	<u>2,142,647</u>	0.4284	<u>9,180</u>
TOTAL	<u>69,177,907</u>		<u>346,425</u>

TOTAL COMPANY 1,246,279

DELTA NATURAL GAS CO., INC.  
Rate Base and Return  
Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
Schedule 6

<u>Line Number</u>		<u>Amount</u>
1	Total utility plant in service per books	<u>182,191,296</u>
2	Add: Materials and supplies (13 mo avg)	434,879
3	Prepayments (13 mo avg)	1,609,440
4	Less: KPSC prepaid	(47,440)
5	Gas in storage (13 mo avg)	9,879,627
6	Unamortized debt expense per books	5,704,177
7	Cash working capital allowance (1/8 O&M)	<u>1,451,645</u>
8	Subtotal	<u>19,032,328</u>
9	Deduct: Accumulated depreciation per books	(61,275,499)
10	Depreciation adjustment (Schedule 4)	(292,968)
11	Cost of removal	(831,877)
12	Customer advance for construction	(51,708)
13	Accumulated deferred income taxes	<u>(21,216,188)</u>
14	Subtotal	<u>(83,668,240)</u>
15	Rate base	117,555,384
16	Weighted cost of capital	<u>8.867%</u>
17	Return	10,423,457
18	Test year operating income	<u>7,018,057</u>
19	Operating income adjustment	<u><u>3,405,400</u></u>



DELTA NATURAL GAS CO., INC.  
Income Taxes  
Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
Schedule 7

<u>Line Number</u>		<u>Schedule</u>	<u>Amount</u>
1	Return, net of tax	6	10,423,457
2	Interest deduction	8	<u>5,191,879</u>
3	Equity portion of return		<u>5,231,578</u>
4	Application of tax rate to equity return 37.96%	7.1	1,985,907
5	ITC amortization (A/C 1.420)		(37,300)
6	Amortization of regulatory liability (A/C 1.410.01)		<u>(65,800)</u>
7			1,882,807
8	Tax expansion factor		<u>1,611,863.3</u>
9	Total income tax liability		<u>3,034,828</u>
10	Tax expansion factor, including PSC assesment		<u>1,616,307.9</u>
11	Total income tax liability, including PSC assesment gross up		<u>3,043,196</u>
12	Income tax expense, per books		<u>1,138,000</u>
13	Income tax adjustment		<u><u>1,905,196</u></u>

Computation of Pro Forma Effective Income Tax Rate

<u>Line Number</u>		<u>Amount</u>
14	Pre-tax net income	8,266,406
15	Total income tax liability	<u>3,034,828</u>
16	Net income	<u><u>5,231,578</u></u>
17	Pro Forma Effective Income Tax Rate	<u><u>36.713%</u></u>

DELTA NATURAL GAS CO., INC.  
Computation of Composite Income Tax Rate  
Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
Schedule 7.1

<u>Line Number</u>		<u>Amount</u>
1	Assume pre-tax income of	100
2	State income tax rate of	<u>6.00%</u>
3	State income tax	<u>6.00</u>
4	Taxable income for Federal income tax computation	94.00
5	Federal income tax rate	<u>34.00%</u>
6	Federal income tax	<u>31.96</u>
7	Total state and federal income tax	<u>37.96</u>
8	Therefore, the composite rate is	<u>37.96%</u>
9	Federal	31.96%
10	State	<u>6.00%</u>
11	Total	<u>37.96%</u>

DELTA NATURAL GAS CO., INC.  
 Capital Structure and Interest Expense  
 Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
 Schedule 8

Line Number		Amounts	Ratios	Cost Rates	Weighted Cost of Capital
1	Equity				
2	Per DNG Balance Sheet	(52,736,947)			
3	Remove net unbilled impact	1,482,514			
4	Subsidiaries	<u>621,393</u>			
5		(50,633,040)	39.67%	12.100%	4.800%
6	Long Term Debt	(59,870,000)	46.90%	6.814%	3.196%
7	Short Term Debt	<u>(17,146,346)</u>	13.43%	6.487%	<u>0.871%</u>
8		<u>(127,649,386)</u>			<u>8.867%</u>

Calculation of Pro Forma Interest Expense and Adjustment

Cost of Long Term Debt, December 31, 2006			
9	7.000% Debentures	19,990,000	1,399,300
10	5.750% Debentures	<u>39,880,000</u>	<u>2,293,100</u>
11			3,692,400
12	Debt Expense Amortization		<u>387,263</u>
13	Annual Long Term Debt Expense	<u>59,870,000</u>	<u>4,079,663</u>
14	Rate		<u>6.814%</u>
Cost of Short Term Debt, December 31, 2006 (rate as of 4/1/07)			
15	6.320% Notes payable	17,146,346	1,083,649
16	0.125% Unused line	22,853,654	<u>28,567</u>
17	Annual Short Term Debt Expense	17,146,346	<u>1,112,216</u>
18	Rate		<u>6.487%</u>
19	Total Calculated Interest Expense		5,191,879
20	Per Books		<u>4,967,706</u>
21	Adjustment		<u>224,173</u>

DELTA NATURAL GAS CO., INC.  
Interest Coverage  
Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
Schedule 9

<u>Line Number</u>		<u>Schedule</u>	<u>Test Year</u>	<u>Pro Forma</u>
1	Net income		2,050,351	5,231,578
2	Interest on debt	8	<u>4,967,706</u>	<u>5,191,879</u>
3	Operating income	6	7,018,057	10,423,457
4	Income taxes	7	<u>1,138,000</u>	<u>3,034,828</u>
5	Total		<u>8,156,057</u>	<u>13,458,285</u>
6	Times interest earned			
7	After taxes		<u>1.41</u>	<u>2.01</u>
8	Before taxes		<u>1.64</u>	<u>2.59</u>

DELTA NATURAL GAS CO., INC.  
Reconciliation of  
Filing Requirements Tab 27 Schedule 1 to  
PSC 2 Item 6 d (2)  
Schedule 1  
Test Year Ended 12/31/06

PSC 2 Item 6 d (2)  
Schedule 10

Description	Schedule	Amount	Impact on Return	Return	Impact on Revenue Deficiency	Adjusted Revenue Deficiency
Revenue deficiency and return, per Filing Requirements Tab 27 Schedule 1				10,496,298		5,641,597
Remove medical accrual adjustment	3	65,000	721	10,497,019	66,162	5,707,759
Correct legal expense cutoff errors	3	18,017	199	10,497,218	18,340	5,726,099
Payroll tax adjustment correction	5	(32)	-	10,497,218	(32)	5,726,067
Property tax adjustment	5	25,138	-	10,497,218	25,138	5,751,205
Rate base correction (add back COR to AD)	6	(831,877)	(73,761)	10,423,457	(118,893)	5,632,312
Include PSC assessment in tax expansion factor	7		-	10,423,457	8,368	5,640,680



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

7. Provide the amount of Delta's minimum pension liability as of test-year-end.

RESPONSE:

Zero.

Sponsoring Witness:

John B. Brown





**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

8. Refer to the Application, the Direct Testimony of Glenn R. Jennings ("Jennings Testimony"), page 6.

a. Provide copies of *An Economic Analysis of Customer Response to Natural Gas Prices*, by Frederick Joutz and Robert P. Trost.

b. Has Delta performed any analysis of financial information and operations other than the 3-year margin comparison to determine why it has not been able to earn an adequate rate of return?

- (1) If yes, provide and describe the results of the analysis.
- (2) If no, explain why such an analysis has not been performed.

**RESPONSE:**

- a. Copy attached.
- b. Delta analyzes results each year as it budgets for the next year. Expenses are reviewed and considered. Costs are only incurred if required for Delta's business needs. Delta's attached comparison of the 2003 test year per the Commission's Order in Case 2004-00067 to the 2006 actual for the test year in this current case is attached. This shows the impact of the margin loss.

Sponsoring Witness:

Glenn R. Jennings

# **An Economic Analysis of Consumer Response to Natural Gas Prices**

**Frederick Joutz and Robert P. Trost**

Prepared for the American Gas Association  
March, 2007



# **An Economic Analysis of Consumer Response to Natural Gas Prices**

**Frederick Joutz and Robert P. Trost<sup>1</sup>**

Prepared for the American Gas Association  
March, 2007

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<sup>1</sup> Professors of Economics, George Washington University. Contact information: [fred.joutz@gmail.com](mailto:fred.joutz@gmail.com) and [trost@gwu.edu](mailto:trost@gwu.edu). We are grateful for the support from the AGA, especially the helpful comments from Bruce McDowell, David Shin, and Paul Wilkinson. We are responsible for any remaining errors.

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## Executive Summary

### Introduction and Key Findings

The consumption of natural gas per household has been declining, on a weather-normalized basis, since about 1980. Over time, natural gas consumers have been tightening their homes, purchasing more efficient appliances and turning down their thermostats. Given the significant increase in natural gas prices since 2000, the American Gas Association (AGA) decided to examine whether or not the trend in declining use has changed in this higher-priced environment. The results of this study are based on monthly data submitted by 46 local natural gas distribution companies that serve nearly 30 percent of all residential natural gas customers throughout the U.S. Some companies submitted data as far back as the early 1980's. The key findings of the study are as follows.

- A trend in declining use per residential natural gas customer of 1 percent annually has been documented<sup>2</sup> back to 1980. This decline rate has accelerated since the year 2000.
  - Weather-adjusted use per residential customer fell by 13.1 percent from 2000 through 2006.
  - The annual rate of decline in this 2000 to 2006 timeframe more than doubled relative to the pre-2000 period, increasing to 2.2 percent annually.
  - Further acceleration was witnessed in the 2004 to 2006 period, as evidenced by a 4.9 percent annual rate of decline.
  - The decline in use per customer has accelerated since 2000 in all 9 geographic regions analyzed.
  
- No appreciable changes in the price elasticity of demand were observed post-2000. Price elasticity of demand refers to the percentage change in demand for a good relative to a percentage change in price. Although the elasticity has not changed over time, it should be noted that natural gas is an essential product that provides heat, hot water and cooking. Despite the essential nature of natural gas, consumers have continued to reduce their consumption at a relatively constant rate with respect to changing prices. Therefore, the large price increases post-2000 have resulted in the large consumption declines noted above.
  - This study found a short-run price elasticity of  $-0.09$  and a long-run price elasticity of  $-0.18$ . (Long-run elasticity refers to a period of time long enough for consumers to change the capital stock of their energy consuming equipment and the shell efficiency of their homes.)

---

<sup>2</sup> 2004 AGA Energy Analysis: Patterns in Residential Natural Gas Consumption, 1980-2001.

- These price elasticity estimates are relatively consistent with previous works on this subject.
- The econometric analysis presented in this study predicts a decline of 13.9 percent between 2000 and 2006; the actual decline was 13.1 percent. The decline is attributable to a price effect and the longer-run trend towards tighter homes and more efficient appliances. The price elasticity effect is 7.9 percent - equal to the elasticity estimate of -0.18 times the 44 percent real price increase. The remaining 6.0 percent is explained by the longer-run trend towards tighter homes and more efficient appliances.
- As a general rule of thumb, at the national level we would expect a 10 percent increase in the price of natural gas to result in nearly a 3 percent decline in the average residential use per customer 12 months later – 1 percent attributable to more conservation with existing appliances, 1 percent attributable to the price-induced purchase of more efficient appliances, and 1 percent attributable to the natural turnover of equipment that occurs annually.

### Background

Residential natural gas consumption is strongly influenced by three factors: seasonal heating needs; response to price change; and the efficiency changes in appliances and home shells caused by a natural turnover rate to more efficient homes and gas appliances. On a weather-adjusted basis, the price and the long run conservation effects are key determinants of changes in residential natural gas consumption. The price effects can be further decomposed into short-term and long-term effects. Short term effects are decisions made by consumers with the current capital stock. Residential customers “turning down the thermostat” would be considered a short term effect. Long term effects are distinguished from short term effects by the inclusion of the decision to purchase more efficient energy consuming appliances and prematurely retiring less efficient ones. The price elasticity in the long-run is the sum of (1) the short-run demand and (2) the additional changes that occur to quantity demanded one year later because of natural gas price effects on the efficiency of the appliance capital stock and on the shell efficiency of homes<sup>3</sup>. While the separate efficiency and conservation effects due to appliance and housing shell turnover are difficult to disentangle in the current sample, they do appear to be discernable from the long term price effects.

To address these issues, AGA commissioned a study to document changes in use per residential customer on a weather normalized basis, particularly since the year 2000, and to identify the reasons for these changes. Other objectives of this study were: to obtain updated elasticity estimates for all nine US Census Regions and for the US; to test for an increase in

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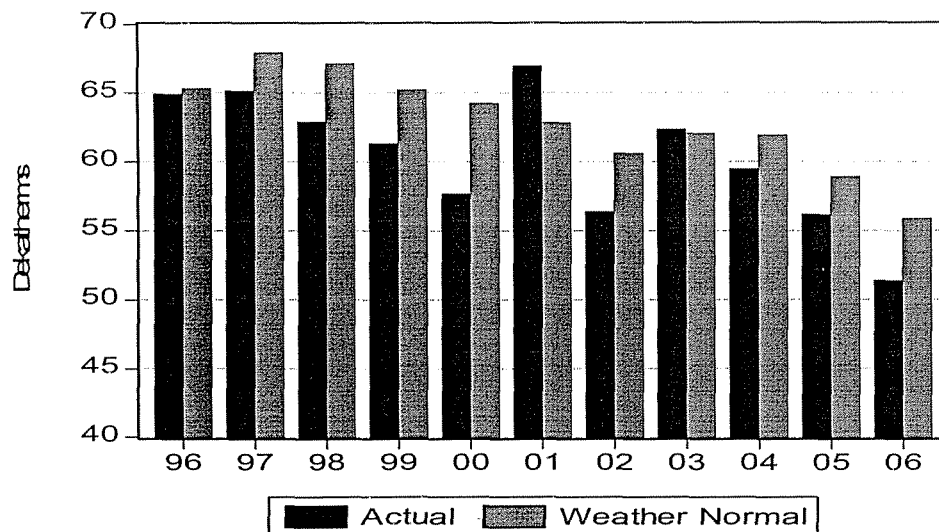
<sup>3</sup> It should be noted that if natural gas prices decrease, consumers will not replace recently purchased efficient equipment with less efficient equipment. So there may be asymmetry with respect to the impact of natural gas prices on appliance and shell efficiency. The efficiency gains in appliance equipment that have occurred in the last several years will not disappear if natural gas prices go down. However, declining prices may lead consumers turning up thermostats to increase comfort levels (in the short-run). In the very long-run, a decline in prices could lead to an increase in burner tips per customer.

the price elasticity of demand for natural gas since the year 2000; and to estimate a natural rate of decline in use per customer due to technology-induced gains in appliance and shell efficiency and a change in conservation attitudes that would occur even in an environment of constant real natural gas prices.

Decline in Use per Customer

Demand for natural gas per residential customer has been declining since the 1980's, and in recent years this decline has accelerated. Between 1980 and 2001, weather adjusted natural gas use per consumer in the US declined almost 1 percent on an annual basis. Since 2000, however, the decline for winter only use has accelerated, decreasing 13.1 percent nationally between 2000 and 2006 for the sample of companies analyzed in this report. Figure ES1 below shows the winter season use per customer in actual and weather normal dekatherms from 1996-2006 using the data collected by AGA.<sup>4</sup> It is clear that actual and weather normalized use per customer has been declining since 1997 and this decline has accelerated since 2004.

**Figure ES1  
US Annual Winter Use per Customer**



<sup>4</sup> The data was collected from 46 Local Distribution Companies (LDCs) in 29 states, representing 28 percent of all residential customers. An LDC is a gas utility that serves a specific rate jurisdiction. Some of the companies in this sample have multiple jurisdictions in their corporate structure. The winter season for this report is defined as the sum of the monthly consumption between October and March.



Table ES1 disaggregates the national winter season weather normal use per residential customer across the nine US Census Regions and for the US. The decline in weather normal use per customer has occurred across all US Census regions. The decline ranges from 5.7 dekatherms per customer for the West South Central region to 10.9 dekatherms for the East North Central region. The percentage decline in use per customer ranged from 9.2 percent for the Middle Atlantic Region to 14.8 percent for the Pacific Region.

**Table ES1**  
**Annual Winter Season Weather Normal**  
**Natural Gas Use per Residential Customer,**  
**By Region and for the U.S.**  
**(Dekatherms per Customer)**

Census Region	2000	2001	2002	2003	2004	2005	2006	Percent Change
National	64.3	62.8	60.6	62.0	61.9	58.9	55.9	-13.1%
East North Central	81.1	79.2	80.1	77.8	76.1	73.1	70.2	-13.4%
East South Central	64.9	64.2	61.3	62.2	60.8	58.7	55.9	-13.9%
Middle Atlantic	93.7	95.0	91.2	93.5	92.8	88.3	85.1	-9.2%
Mountain	80.6	77.9	75.8	76.4	71.8	72.0	70.5	-12.5%
New England	80.7	79.8	75.3	82.3	80.3	75.9	72.4	-10.3%
Pacific	43.8	40.9	40.0	41.8	40.6	40.4	37.3	-14.8%
South Atlantic	71.7	69.4	63.8	69.1	62.0	62.5	62.5	-12.8%
West North Central	80.1	79.5	79.8	80.4	78.3	75.9	70.2	-12.4%
West South Central	46.3	46.4	40.2	44.1	54.1	41.7	40.6	-12.3%

#### Price Elasticity and “Natural” Conservation Estimates

This study found that neither a practical nor statistically significant change in the price elasticity of residential natural gas consumption occurred in the post year 2000 period. The price elasticity of residential natural gas demand appears to have remained relatively constant since the 1990s. This implies the large percentage price increase since 2000 accounted for the decline in natural gas use, rather than an increased sensitivity or greater response by households to a given price change. The study also found that independent of natural gas price increases, the naturally occurring decline due to the technology driven gain in appliance and home thermal shell efficiency, as well as changes in conservation attitudes was 1 percent per year.

Table ES2 illustrates that for the sample of companies in the study, the short run price elasticity of demand averaged -0.09, while the long run estimated averaged -0.18. Therefore, given a 10 percent increase in the price of natural gas, consumption would decline 2.8 percent; 1.8 percent for price response, added to 1.0 percent decline due to the normal turnover of appliances and other “natural” conservation measures. There is very little regional variation in the total impact of a 10 percent increase in real prices on use per

customer. The impact in all regions was close to the national estimate of 2.8 percent, with the Mountain region being the lowest at 1.9 percent and the South Atlantic region being the highest at 3.7 percent.

The study also found that the elasticity estimates calculated using the sample data were generally consistent with the elasticity estimates found in the energy economics literature.<sup>5</sup>

**Table ES2**  
**Summary of National and Regional**  
**Natural Gas Price Elasticity Estimates\***

Region	Short-run elasticity	Long-run elasticity**	Annual Time Trend	Total Response to a 10% Price Increase***
National	-0.09	-0.18	-1.0%	-2.8%
East North Central	-0.08	-0.22	-1.0%	-3.2%
East South Central	-0.01	-0.01	-2.0%	-2.1%
Middle Atlantic	-0.10	-0.20	-1.3%	-3.3%
Mountain	-0.07	-0.10	-0.9%	-1.9%
New England	-0.08	-0.25	-0.4%	-2.9%
Pacific	-0.07	-0.12	-0.8%	-2.0%
South Atlantic	-0.12	-0.29	-0.8%	-3.7%
West North Central	-0.09	-0.15	-1.1 %	-2.6%
West South Central	-0.13	-0.16	-1.6%	-3.2%

\* Estimates obtained from the “fixed effects” pooled regression

\*\* Cumulative: includes impacts of short-run elasticities

\*\*\* The total response to a 10% price increase is the sum of the long-run elasticity and the annual time trend effect.

### Implications

These price elasticity estimates and the natural conservation trends are able to explain the post 2000 winter consumption per household per customer actual experience.

Between 2000 and 2006, real natural gas prices for the sample companies in this study rose 44 percent, which according to our analysis would lead to approximately a 7.9 percent (0.18 x 44 percent) decline in use per customer by the year 2006. In addition to this 7.9 percent price induced decline in weather normal use per household, there would be an additional 6.0 percent (6 x 1.0 percent) decline because of the natural annual rate of turnover of old gas appliances to newer more efficient appliances. Hence, our analysis predicts a decline of 13.9 percent over the six-year period, which is very close to the actual decline of 13.1 percent.

<sup>5</sup> See Appendix C of the main report for a summary of the elasticity estimates found in the energy economics literature.

<i>Overall decline</i>		<i>Price Effect</i>		<i>Conservation and</i>
<i>in Winter Gas Use</i>	=	<i>Elasticity with</i>	+	<i>Turnover to More</i>
<i>per Customer</i>		<i>Price Increase</i>		<i>Efficient Appliances</i>
13.9%	=	0.18 x 44%	+	6 x 1.0%
	=	7.9%	+	6.0%

In the expression above, the left hand term is the overall predicted decline of winter gas use per customer, the first term on the right hand side is the price effect reflecting the elasticity estimate multiplied by the price increase, and the second term the effect from conservation and turnover to more efficient appliances that occurs naturally every year with or without a price increase.

The results from analyzing the AGA sample data lead to a general rule of thumb. This rule does not apply to all companies in all situations, but the general rule with its caveats provides valuable insight to the underlying processes governing consumer behavior. This rule appears to capture consumers' winter price sensitive consumption behavior reasonably well across both the LDCs and Census regions. Twelve months after a 10 percent increase in natural gas prices at the national level, there will be nearly a 3 percent decline in natural gas use per customer on a national level. This 3 percent decline is comprised of about a 1 percent drop in gas use with the current capital stock, about a 1 percent drop in use per customer because households respond to the higher gas prices by replacing still functional appliances with more efficient units, and about a 1 percent drop in gas usage per customer due to the natural turnover of old gas appliances to the more efficient gas appliances that are available in the market each year. This rule of thumb will vary by LDC because they are heterogeneous in terms of weather, housing stocks, and standards of living.

Other factors that impacts residential energy use are the many programs that encourage consumers to save energy. These include:

- The federal government encourages conservation through weatherization programs funded by the Low-Income Household Energy Assistance Program (LIHEAP), tax credits for the purchase of efficient appliances and housing shell improvements, and consumer education on the importance of saving energy.
- State and local governments also encourage efficiency through similar programs.
- Many utilities provide rebates, incentives, and assistance to their customers to conserve energy use. For example, electric and natural gas utilities provided more than \$140 million in 2005 to assist low-income customers to weatherize their homes.<sup>6</sup>

From a planning and policy perspective, even if gas prices do not increase in a given year, there will still be approximately a 1 percent fall in gas usage per household in the following

<sup>6</sup> Source: <http://liheap.ncat.org/tables/FY2005/05stlvtb.htm>

year. This is driven by the historical forces related to the natural turnover of old appliances to the more efficient appliances that are available on the market each year. The annual time trend impacts will vary somewhat by LDC, because of regional differences in weather, appliance stocks, housing shell efficiency, demographic and economic characteristics.

There is a caveat. We cannot address whether the phenomenon will continue at the same rate for the long-term. Further gains in efficiency in absolute and relative terms may or may not have the same impact as they did previously. This is an issue for more detailed engineering studies on the efficiency of appliances and housing shells and economic research on the change in conservation habits of consumers for energy use and winter season comfort levels. We would note, however, that legislative and regulatory pressure for greater efficiency is likely to increase as climate change becomes a more pronounced national and international priority.

The policy implications of the 13.1 percent decline since 2000 are significant. First, regulators must recognize these trends and allow rate structures to incorporate these variations. Second, the natural turnover of appliances and increases in thermal shell efficiency from new construction will result in continued conservation, impacting utility operations. Third, even if future natural gas prices remain constant or even decrease, the appliance and house shell efficiency gains achieved in prior years will not be reversed.

#### Future Research

As with any study, there is room for future research. Suggestions for future research are the following:

- Obtain data from natural gas companies that did not participate in the initial study.
- Try different specifications of the model.
- Use the Iterative Bayes Shrinkage Estimation Technique to get individual LDC parameter estimates.
- Consider the impact of competition from the electric utility industry.

## Introduction

Demand for natural gas per residential customer has been declining since the 1980's, and in recent years this decline has increased. Between 1980 and 2001, weather adjusted natural gas use per consumer in the US declined almost 1 percent on an annual basis. Since 2000, however, the decline for winter only use has accelerated, decreasing 13.1 percent between 2000 and 2006 for the sample of companies analyzed in this report.

It is important from a budgeting point of view for Local Distribution Companies (LDCs) to understand the cause of this decline. Was it caused by the recent increases in natural gas prices and customer's response to these price increases? Did customers change their behavior in response to these price increases? Have they become more sensitive to natural gas price movements or has the price induced response behavior remained relatively the same over time? Did customers switch to more efficient gas appliances in response to these natural gas price increases? Is it due to technological innovations which lead to increased efficiencies in appliances and thermal shells of homes? These efficiencies are in some sense passive as older appliances are replaced with more efficient models through natural attrition.

To address these issues, the American Gas Association (AGA) funded a study to re-estimate the price elasticity of natural gas demand by residential households using a sample of data that covers the recent period of large natural gas price increases. The main objective of this study was to document changes in use per residential customer on a weather normalized basis, particularly since the year 2000, and to identify the reasons for these changes. A second purpose of this study was to test for an increase in the price elasticity<sup>7</sup> of demand for natural gas since the year 2000. A third and equally important purpose of this study was to obtain updated elasticity estimates for all nine US Census Regions and for the US as a whole. Finally, the study attempts to estimate a natural rate of decline in use per customer due to technology induced gains in appliance and shell efficiency that would even occur in an environment of constant real natural gas prices.

There are hundreds of studies on the elasticities of natural gas demand. These studies have generated a range of elasticity estimates. If one goes back to the 1970's and even to the 1960s, these estimates vary over a wide range. Estimates of short-run price elasticity range from as low as  $-0.05$  in Beirlein, Dunn and McConnon (1981) to a high of  $-0.68$  in Barnes, Gillingham & Hagemann (1982). For long-run price elasticity estimates, the range of estimates is even higher, with the low being  $-0.017$  in Hewlett (1977) to a high of  $-3.42$  in Beirlein, Dunn and McConnon (1981). See Dahl and Roman (2004) and Dahl, et. al. (2005) for recent surveys of energy elasticity demand estimates. Other surveys of energy demand price elasticity estimates are Taylor (1975 and 1977), Bohi (1981), Bohi and Zimmerman (1984), Al-Sahlawi (1989), Dahl (1993), and Espy and Espy (2004). See Appendix C for a brief literature review of price elasticity estimates.

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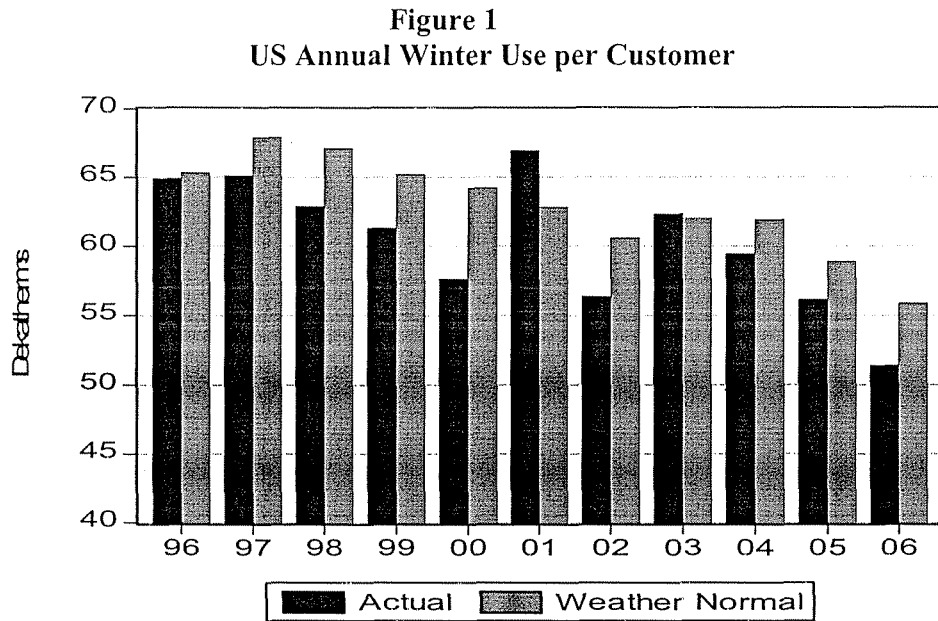
<sup>7</sup> The price elasticity of demand is defined as the ratio of the percent change in quantity demanded of a particular good to the percent change in the price of that good, such as natural gas demand in this study.

Many of the studies estimated elasticities of natural gas demand with data aggregated at the state and national level and collected by the States; or collected by the Energy Information Administration (EIA). Examples of these are Balestra and Nerlove (1966), Jaskow and Baughman (1976), Berndt and Watkins (1977), and more recently, Maddala, Trost, Li, and Joutz (1997). Other studies use individual micro data to estimate demand elasticities. Examples of these are Hewlett (1977), Barnes, Gillingham and Hagemann (1982), and Green and Gilbert (1983). While the former studies using state and national aggregate data may provide some useful information at the state and national level, and the latter studies may provide good estimates of individual demand elasticities, neither provide adequate estimates at the individual LDC level of aggregation. Most of these studies do not allow for a natural rate of decline in use per customer due to technologically induced efficiency gains in appliances and thermal shells of homes. In addition, there are few, if any, studies that use current data that includes the recent run-up in natural gas prices. This study will fill these gaps in the literature by using high quality data collected and compiled at the individual LDC level and covering the period as recent as March, 2006.

This paper is divided into the following five sections. In Section 1, background information at the regional, as well as the national level, is provided. The information includes residential natural gas consumption, the declining trend of consumption, and price movements. In Section 2, the database constructed from the survey of LDCs is described. Section 3 explains the mathematical equations used to estimate short- and long-run price elasticity of demand. Empirical results of short-run and long-run elasticity and the declining trend in gas usage are presented in Section 4. The report concludes in Section 5 with a summary of the results and policy implications. In addition, there is a list of suggestions for future research. References and technical appendices can be found at the end of the report. The appendices include construction of the weather-normalized series for use per customer, a map of the Census regions, a brief literature review, and a discussion of statistical hypothesis testing.

## Section 1: Background

Residential natural gas consumption per customer in the US has been declining. Figure 1 below shows the winter season use per consumption actual and weather normal (in dekatherms) from 1996 to 2006 using the data collected from the sample LDCs. The winter season for this report is defined as the sum of the monthly consumption between October and March.



**Table 1: US Annual Winter Use per Residential Customer in Dekatherms**

Year	Actual		Winter Normal	
	Level	Percent Change	Level	Percent Change
1996	64.9		65.3	
1997	65.2	0.5	67.9	4.0
1998	62.9	-3.5	67.1	-1.2
1999	61.3	-2.5	65.2	-2.8
2000	57.7	-5.9	64.3	-1.4
2001	67.0	16.1	62.8	-2.3
2002	56.4	-15.8	60.6	-3.5
2003	62.3	10.5	62.0	2.3
2004	59.5	-4.5	61.9	-0.2
2005	56.2	-5.6	58.9	-4.9
2006	51.4	-8.5	55.9	-5.1
<b>Annual Percent Change 1996-2000</b>		<b>-1.64</b>	<b>-1.48</b>	

As can be seen from Figure 1 and Table 1, there has been a marked decline in weather normal use per customer. The annual percent change from 1996 to 2006 was -1.64 percent and -1.48 percent respectively, for actual and weather normal consumption. Since 2000, however, the decline for winter only use has accelerated, decreasing 13.1 percent between 2000 and 2006 and by 9.7 percent between 2004 and 2006 for the sample of companies analyzed in this report.

The phenomenon of declining weather normal use per customer is not new<sup>8</sup>. Some even feel it started on February 1, 1977 when then President Jimmy Carter, after only two weeks in office, said in his now famous fireside chat:

*“All of us must learn to waste less energy. Simply by keeping our thermostats, for instance, at 65 degrees in the daytime and 55 degrees at night we could save half the current shortage of natural gas.”*

In the years since, the first President Bush established the first National Energy Strategy in June of 1989, and the government has imposed efficiency standards, subsidized technological improvements in both shell and appliance efficiency, and generally encouraged its citizenry to conserve on energy. Efficiency improvements are sure to continue, and if natural gas prices stay high, it will most certainly encourage natural gas

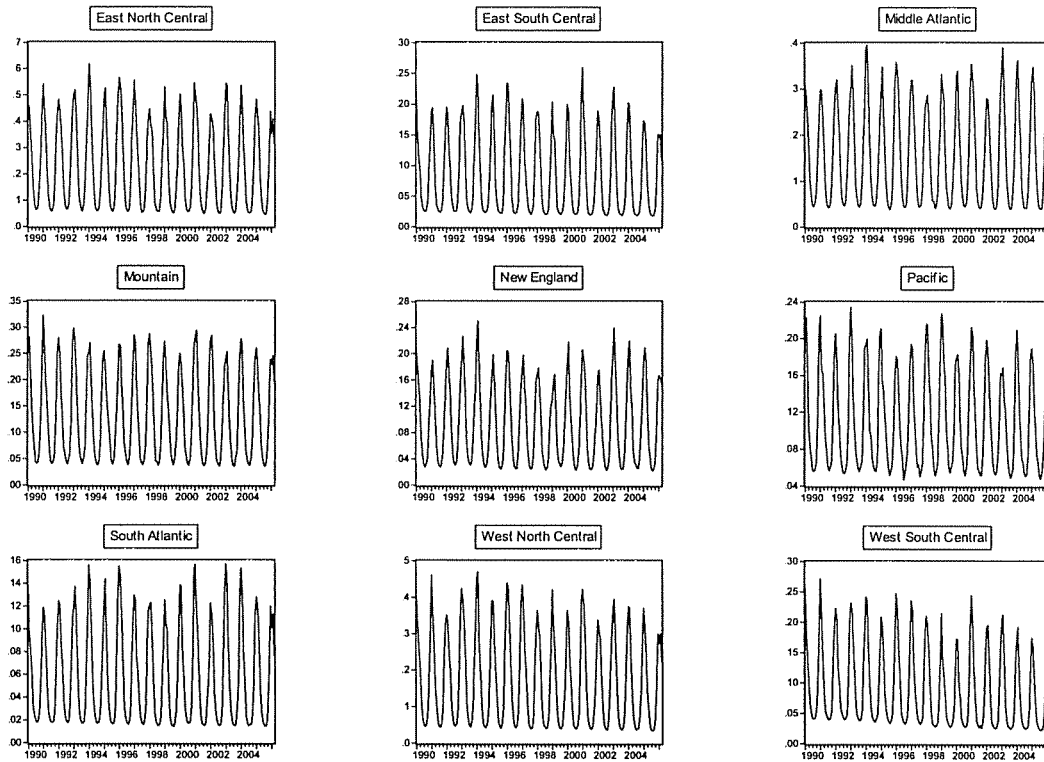
<sup>8</sup> Between 1978 and 1982, energy consumption per household actually decreased by 26%. See EIA’s Annual Energy Review, URL [http://www.eia.doe.gov/emeu/aer/ep/ep\\_frame.html](http://www.eia.doe.gov/emeu/aer/ep/ep_frame.html).



customers to trade in old inefficient appliances for newer more efficient ones. The impact on the natural gas industry will be an obvious decrease in revenue accruing to natural gas LDC's.

This study will examine the reasons for this decline in use per customer, with particular emphasis on estimating the short-run and long-run price elasticity of natural gas demand since the year 2000. It will also analyze and measure the rate of decline caused by the natural turnover rate of old inefficient appliances with newer more efficient ones. The trends in the AGA sample are validated from trends in other data. The U.S. Energy Information Administration (EIA) reports aggregate estimates of residential consumption in BCF/day and residential prices in \$/MCF on a monthly basis from 1990 to the present. The EIA sample data covers all LDCs in the US. These series are plotted by US Census Region in residential consumption per household per day in Figure 2 and in nominal and real terms in (\$2000)/MCF in Figure 3 below. A map of the US Census Regions is shown in Appendix B. These figures provide a comparison with the subsequent figures from the AGA survey database. They demonstrate that the trends and patterns in the survey are consistent with a recognized national source of data even before adjusting for normal weather.

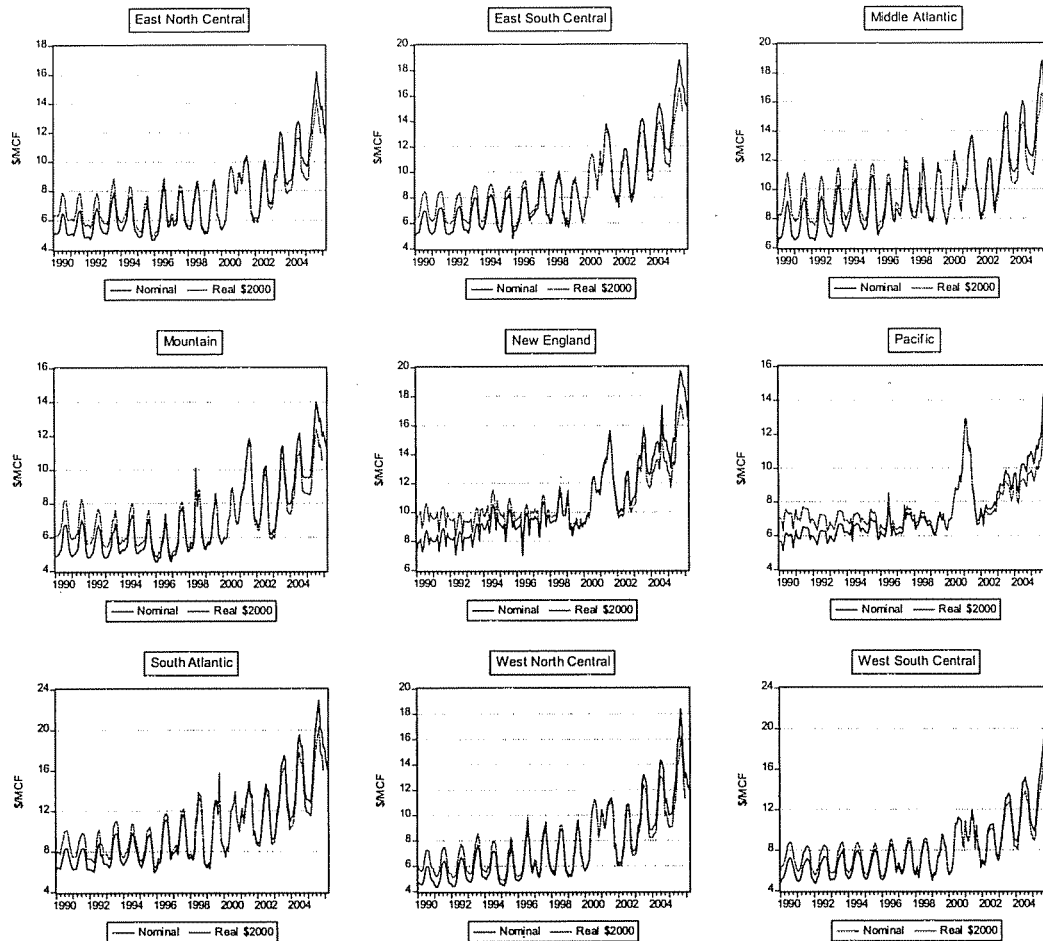
**Figure 2**  
**Regional Consumption per Customer per Day**  
**Mcf per Day**



Source: U.S. Energy Information Administration

Regional consumption per customer appears to decline for every region for most of the period and particularly after 2000. This has occurred while residential natural gas prices have more than doubled over the same period.

**Figure 3**  
**Nominal and Real (\$2000) Delivered Natural Gas Prices**



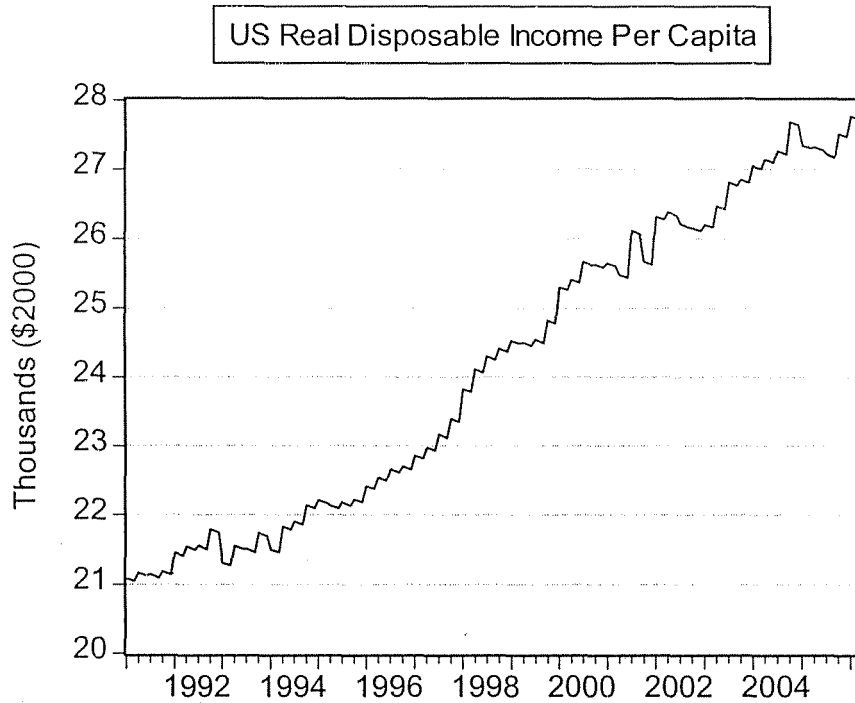
Source: U.S. Energy Information Administration

Residential natural gas prices were fairly stable between 1990 and 1997 during the so-called “gas bubble” period. However, they have been increasing, particularly since 2000 due to a variety of factors, including increasing oil prices (Villar and Joutz, October 2006). Nominal prices have risen faster in some regions than in others; the spread in nominal terms has been between \$12/MCF to almost \$20/MCF. The real price has more than doubled to over \$12/MCF. Natural gas prices have risen about 35 percent to 40 percent faster than the general U.S. price level since 1990. Figure 3 shows the monthly residential natural gas prices per MCF according to the EIA. Figure 4 shows U.S. real disposable

income per capita has risen about 33 percent from \$21,000 to \$28,000 today.

While income is important in any economic analysis of demand, income was not included in our final model for several reasons. First, estimates of real disposable income (per customer, household, or person) are difficult to obtain at the LDC level, which is the building block of this research. Second, the services from natural gas is a normal good, one would expect a positive income effect, which should have been reflected in a positive trend in natural gas use per household. However, in our sample and specification, we observe a negative trend in use per household. The income series are highly positively autocorrelated and trend-like; see Figure 4. The income coefficient(s) were erratic and even negative. This is consistent with the declining use per household due to a naturally occurring and non-natural gas price-induced replacement of old inefficient appliances with new more efficient appliances. At present, we believe a time trend appropriately captures this new technology-induced naturally occurring adoption of more energy efficient appliances and improvements in housing shell efficiency or conservation. Third, our findings are similar to surveys of natural gas demand by Bohi (1981), Dahl (1993, and personal discussions about preliminary results regarding an update to Dahl's previous study). In a number of papers, Bohi dismisses the large income elasticities from some static cross section estimates and concluded that income is not found to be an important variable in natural gas demand. Dahl found that income effects in residential demand models are consistently small in both aggregate and disaggregate data. Both authors suggest that representing the income effect in residential is problematic and sensitive to the particular study.

Figure 4



Source: Bureau of Economic Analysis, U.S. Department of Commerce

Table 2 shows the cumulative decline of winter weather normal use per customer between 2000 and 2006 for the sample of the LDCs. The focus of Table 2 is the post 2000 period. The intent is to capture the effects of the large increases in natural gas prices and (possible) conservation activities by consumers.<sup>9</sup> The fall, on average, is greater than two per cent per year for six of the nine Census Regions and for the U.S.

<sup>9</sup> The pre-2000 period will be addressed in the statistical modeling sections.

**Table 2**  
**Annual Winter Season Weather Normal Natural Gas Use per**  
**Residential Customer, By Region and for the U.S.**  
**(Dekatherms per Customer)**

Census Region	2000	2001	2002	2003	2004	2005	2006	Percent Change
National	64.3	62.8	60.6	62.0	61.9	58.9	55.9	-13.1%
East North Central	81.1	79.2	80.1	77.8	76.1	73.1	70.2	-13.4%
East South Central	64.9	64.2	61.3	62.2	60.8	58.7	55.9	-13.9%
Middle Atlantic	93.7	95.0	91.2	93.5	92.8	88.3	85.1	-9.2%
Mountain	80.6	77.9	75.8	76.4	71.8	72.0	70.5	-12.5%
New England	80.7	79.8	75.3	82.3	80.3	75.9	72.4	-10.3%
Pacific	43.8	40.9	40.0	41.8	40.6	40.4	37.3	-14.8%
South Atlantic	71.7	69.4	63.8	69.1	62.0	62.5	62.5	-12.8%
West North Central	80.1	79.5	79.8	80.4	78.3	75.9	70.2	-12.4%
West South Central	46.3	46.4	40.2	44.1	54.1	41.7	40.6	-12.3%

Table 2 shows the overall decline between 2000 and 2006 for the AGA sample of LDCs. As shown in Table 2, the decline in weather normal use per customer for the national sample is from 64.3 dekatherms in 2000 to 55.9 dekatherms per household in 2006. This represents a cumulative decline of 13.1 percent or an average decline of 2.2 percent per year. The decline since 2004 is even more dramatic, going from 61.9 dekatherms per household in 2004 to 55.9 dekatherms in 2006, nearly a 6 percent decline per year. As shown in this table, every region in the US experienced a decline in use per residential customer.

## Section 2: Data

Sixteen AGA member companies provided data for this study. The companies supplied monthly data on residential consumption, average prices, number of customers, heating-degree data, and economic data. Most companies were able to provide a time series of data starting in 1992 and in some cases even into the 1980s. Three companies were unable to contribute data prior to 1999 for accounting or reorganization reasons. The remaining fifteen corporations comprise 46 local distribution companies. This represents more than 16 million customers and 28 percent of all residential customers nationwide.

Micro data on individual consumers is best suited for obtaining estimates of price elasticities. In rate case decisions and in internal LDC corporate strategy decisions however, the most relevant and useful piece of information is how the external forces that bombard it now impact the LDC. These external forces can vary from announcements by Presidents, changes in a competitors pricing, new gas appliance technologies, economic recessions, and gas price increases imposed by fuel surcharges. Since it is the impact of these forces on actual individual LDC's that is relevant, current data on consumption and prices collected by each individual LDC and aggregated at the individual LDC level is best suited to measure the impact of these external forces on a LDC in the current time period.

But data on a single LDC is often not enough information. The problem with using current data from only one LDC is that the number of observations will be quite small, and statistical reliability will be compromised. Instead of tens of thousands of observations on individual consumers, one may be left with 50 or 60 observations for any given LDC during the important winter season months. From a statistical reliability point of view then, it is important to obtain on many different individual LDCs, data that are collected by each individual LDC rather than using survey data collected by government agencies such as the EIA.

In this study, the breadth and depth of the data collected by the AGA has not to our knowledge been done before. The breadth of the data spans the entire US, covering 46 different LDCs. The depth of the data covers almost a decade or more for most of the companies. Therefore, this is a data set that is uniquely suited for the analysis of residential natural gas consumption in the US.

The number of LDCs in each of the nine Census Regions and the percent of total customers the sample covers for each Region is given in Table 3 below.

**Table 3**  
**Percent of Total Residential Customers Represented by the AGA Sample**

<b>Census Regions</b>	<b>Census Abbreviation</b>	<b>Number of participating LDCs</b>	<b>Coverage</b>
East North Central	ENC	3	8%
East South Central	ESC	3	11%
Mid-Atlantic	MAC	6	45%
Mountain	MTN	5	42%
New England	NEC	8	50%
Pacific	PAC	5	39%
South Atlantic	SAC	5	17%
West North Central	WNC	3	20%
West South Central	WSC	8	32%

### **Section 3: Approaches to Estimating Short- and Long-run Price Elasticity of Demand**

Economists often distinguish between a short-run response and long-run response when referring to how a household changes its natural gas usage when faced with price and income changes. The short-run response is defined as a household's natural gas demand response to natural gas price and income changes given their current capital stock of natural gas-using appliances and shell efficiency of the house. The long-run response is defined as a household's response to natural gas prices changes and income changes after the household has had time to change their stock of gas using appliances and house shell efficiency.

The idea behind the short-run and long-run responses to price changes is that when natural gas prices change, a household's short-run response is to alter the intensity with which they use their current stock of natural gas-using appliances. The long-run response to a change in natural gas prices is to alter the number and efficiency of natural gas using appliances, while at the same time changing the shell efficiency of the house.

A household's percentage change in natural gas demand per one percent change in natural gas price is called the price elasticity of natural gas demand. When this percentage change is computed for a household with a given stock of natural gas-using appliances and house shell efficiency, it is termed the short-run price elasticity of natural gas demand for that household. When this percentage change is computed over a time period long enough to allow a household to change its stock and efficiencies of house and natural gas using appliances, it is termed the long-run price elasticity of natural gas demand for that household. A similar definition is given to short-run and long-run income elasticities of natural gas demand. If the natural gas demand equation is specified in logarithmic form, the price and income coefficients in a regression equation can be interpreted as the price and income elasticities.

#### **A Dynamic Model of Capital Stock Choice and Natural Gas Demand**

For a typical household, natural gas is demanded not for its own sake but for use in furnaces, appliances and the like. The household's accumulated energy saving "capital stock" is determined by income, habits, and past prices of fuels. Consequently, in any period, the household's demand for natural gas is a function of the current price, which influences how intensively the stock of equipment is used, and past prices, which influences the size and composition of that stock. A very simple structural model (Fisher and Kaysen, 1962) of these effects for a given household might be

$$\text{Demand: } Y_t = \alpha + \beta_1 X_{t-1} + \lambda Z_t + \delta(K_t + E_t) + \varepsilon_t \quad (1)$$

$$\text{Equipment: } K_t = \gamma_1 X_{t-12} + \gamma_2 Z_t \quad (2)$$

$$\text{Efficiency: } E_t = \gamma_3 T_t \quad (3)$$



where  $Y_t$  is use per household of weather normalized Natural gas at time  $t$ ,  $X_{t-1}$  is the real (base = \$2000) price of natural gas at time  $t - 1$ ,  $Z_t$  is real (base = \$2000) household income at time  $t$ ,  $K_t$  is capital stock with a given efficiency  $E_t$  at time  $t$ ,  $T_t$  is a annual time trend to capture technological improvements in the efficiency of the capital stock, and  $\varepsilon_t$  is a random error term.

We use the real price lagged one period to capture the short-run response to a price change since the current price is not known until the gas bill arrives in the next billing period. Hence, a household's price-induced consumption adjustment during this period is based on last period's real gas price.

If equation (1) is in natural logarithms for  $Y_t$ ,  $X_{t-1}$  and  $Z_t$ , the coefficient  $\beta_1$  can be interpreted at the short-run price elasticity of natural gas demand. It measures the responsiveness of natural gas demand at time  $t$  to a change in natural gas price at time  $t-1$  for a fixed capital stock of natural gas appliances  $K_t$ . In order to derive the long-run price elasticity of natural gas demand, we need to substitute equations (2) and (3) into equation (1) to get

$$Y_t = \alpha + \beta_1 X_{t-1} + \beta_2 X_{t-12} + \beta_3 Z_t + \beta_4 T_t + \varepsilon_t \quad (4)$$

If all variables except the time trend are in logarithms, then the coefficient on  $X_{t-1}$  is an estimate of the short-run price elasticity, the sum of the coefficients on all price variables is an estimate of the long-run price elasticity, and a negative coefficient ( $\beta_4$ ) on the annual time trend is the decline in use per household of natural gas demand due to the adoption of newer and more efficient capital equipment. Although the length of the lag ( $t-12$ ) on price in equation (2) to capture the capital stock adjustment process is somewhat arbitrary in this formulation, one can put other restrictions on the shape and length of the price and lagged price coefficients by using models such as the Koyck (1954) or Almon (1965) lag.

The coefficient  $\beta_1$  in equation (4) gives the short-run price elasticity of natural gas demand. In equation (4) the coefficient  $\beta_2$  captures capital stock adjustments that depend on past natural gas prices, while still allowing for an annual decline in use per customer that occurs because of a non-gas price induced rate of turnover of the capital stock to more energy efficient equipment. The sum of the coefficients  $\beta_1 + \beta_2$  represents the long-run elasticity of natural gas demand. The coefficient  $\beta_4$  on the time trend variable represents the pure turnover to newer more efficient capital equipment after subtracting out the gas price effect on this turnover rate captured by  $\beta_2$ . A negative coefficient ( $\beta_4$ ) on the annual time trend is the annual decline in use per household of natural gas demand due to the natural adoption of newer and more efficient capital equipment.

## Section 4: Empirical Results Using the AGA Sample of LDCs

The AGA study is interested in answering the following five questions:

- (a) What are the changes in natural gas use per residential customer on a weather normalized basis since the year 2000?
- (b) What is the short-run price elasticity of demand for residential natural gas customers?
- (c) What is the long-run price elasticity of demand for residential natural gas customers?
- (d) Has elasticity of natural gas demand changed since 2000?
- (e) What is the annual reduction in natural gas usage per customer due to the natural replacement of old inefficient natural gas appliances with more energy efficient appliances; and the building of new homes with greater shell efficiencies compared to existing homes?

To answer these questions we estimated two variants of equations<sup>10</sup> (1) to (3). The first variant assumes the short-run price elasticity has a structural shift in the year 2000 and the second model assumes there is no shift in the short-run price elasticity in the year 2000 and beyond. These two equations are given below as (4a) and (4b), respectively:

$$Y_t = \alpha + \beta_1 X_{t-1} + \delta_{2000} X_{t-1} * D2000 + \beta_2 X_{t-12} + \beta_4 T_t + \varepsilon_t, \quad (4a)$$

$$Y_t = \alpha + \beta_1 X_{t-1} + \beta_2 X_{t-12} + \beta_4 T_t + \varepsilon_t, \quad (4b)$$

where all variables except the time trend are in natural logarithms and D2000 is a 0,1 indicator variable, equal to 0 if the time period is pre year 2000, and equal to 1 if the time period is the year 2000 or greater. The dependent variable  $Y_t$  in equations (4a) and (4b) is daily natural gas use per customer in month  $t$ .

In equation (4a), the coefficient  $\delta_{2000}$  is a shift coefficient on the price elasticity given by  $\beta_1$ . The interpretation of  $\delta_{2000}$  is that  $\beta_1$  represents the price elasticity of natural gas demand for the period prior to the year 2000, and  $\beta_1 + \delta_{2000}$  gives the price elasticity of natural gas demand for the year 2000 and beyond. So a negative  $\delta_{2000}$  in equation (4a) would indicate that demand

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<sup>10</sup> We omitted the income variable  $Z_t$  for the reasons outlined the Background Section of the paper. First, estimates of real disposable income (per customer, household, or person) are difficult to obtain at the LDC level, which is the building block of this research. Second, the services from natural gas is a normal good, one would expect a positive income effect, which should have been reflected in a positive trend in natural gas use per household. However, in our sample and specification, we observe a negative trend in use per household. The income series are highly positively autocorrelated and trend-like; see Figure 4. The income coefficient(s) were erratic and even negative. This is consistent with the declining use per household due to a naturally occurring and non-natural gas price-induced replacement of old inefficient appliances with new more efficient appliances. At present, we believe a time trend appropriately captures this new technology-induced naturally occurring adoption of more energy efficient appliances and improvements in housing shell efficiency or conservation.

has become more elastic since the year 2000. The coefficient  $\beta_2$  captures capital stock adjustments that depend on past natural gas prices, while still allowing for an annual decline in use per customer that occurs because of a non-gas price induced rate of turnover of the capital stock to more energy efficient equipment. A negative coefficient ( $\beta_4$ ) on the annual time trend is the annual decline in use per household of natural gas demand due to the adoption of newer and more efficient capital equipment.

The sum of the coefficients  $\beta_1 + \delta_{2000}$  in equation (4a) gives the short-run price elasticity of natural gas demand in the post-2000 period, the sum of the coefficients  $\beta_1 + \delta_{2000} + \beta_2$  represents the long-run elasticity of natural gas demand in the post-2000 period, and the coefficient  $\beta_4$  on the time trend variable represents the pure turnover to newer more efficient capital equipment after subtracting out the gas price effect on this turnover rate captured by  $\beta_2$ .

The interpretation of the coefficients for equation (4b) is similar, except in equation (4b) the slope shift coefficient  $\delta_{2000}$  for the short-run elasticity is constrained to zero.

### Shrinkage Estimators

With a panel data set such as the one used in this study, there is always the question of whether to pool the data and obtain a single estimate of the parameters from the whole sample, or to estimate the equations separately for each cross-section. The implicit assumption in the fixed effects model is that the intercepts are different for each cross-section, but the slope coefficients are the same for all cross sections. This may not be a tenable assumption. Indeed, in practice the constancy of slope coefficients across different cross-section units is often rejected. This implies that the equations should be estimated separately for each cross-section rather than obtaining an overall pooled estimate.

The problem with the two usual estimation methods of either pooling the data or obtaining separate estimates for each cross section is that both are based on extreme assumptions. If the data are pooled as in the fixed effects model, it is assumed the coefficients are all the same. If separate estimates are obtained for each cross section, it is assumed that the coefficients are all different for each cross section. The truth probably lies somewhere in-between. The coefficients are not exactly the same, but there is some similarity between them.

One way to allow for some similarity among the slope coefficients without constraining them to be exactly the same is to assume the coefficients all come from a joint distribution with a common mean and non-zero covariance matrix. This suggests that the resulting coefficient estimates should be a weighted average of the overall pooled estimate and the separate time series estimates based on each cross section. Thus, each cross-section estimate is “shrunk” towards the overall pooled estimate.

For example, consider the model given by equation (4b) and using aggregate data on the nine census Regions to estimate the coefficients. This model is:

$$Y_{it} = \alpha_i + \beta_{i1}X_{i,t-1} + \beta_{i2}X_{i,t-12} + \beta_{i4}T_{it} + \varepsilon_{it},$$

$i = 1, 2, 3, \dots, N$  ( $N = 9$ , Census Regions)

$t = 1, 2, 3, \dots, T$  (Time Periods)

The implicit assumption in the fixed effects model is that we retain the  $i$  subscript on  $\alpha$  but remove the subscript on the  $\beta$ 's. The implicit assumption if we run separate regressions for each cross section is that the  $i$  subscript is retained on both  $\alpha$  and all the  $\beta$ 's.

A shrinkage estimator sometimes suggested is the Stein rule estimator defined by:

$$\tilde{\beta}_i = \left(1 - \frac{c}{F}\right)\hat{\beta}_i + \left(\frac{c}{F}\right)\hat{\beta}_p, \quad (5)$$

where  $\tilde{\beta}_i$  is the shrinkage estimator,  $\hat{\beta}_i$  is the separate ordinary least square (OLS) estimate from each time series,  $\hat{\beta}_p$  is the fixed effects pooled estimator. The  $F$  is the  $F$ -test statistic used to test the null hypothesis that all the  $\beta$ 's are equal across each cross-section. The constant  $c$  is given by

$$c = \frac{(N-1)K - 2}{NT - NK + 2}, \quad (6)$$

and  $K = 3$  and  $N = 9$  in equation 4b.

We will present the shrinkage estimates for the nine Census Regions below when we discuss the regional results.

### National Results

We estimated equations (4a) and (4b) for each of the LDCs using OLS on monthly data for the winter season months<sup>11</sup> of October to March. These results are given in the last column of Tables 4 and 5. The average of these individual LDC estimates indicates that the short-run price elasticity of natural gas demand is  $-0.11$ , the short-run price elasticity shift in post 2000 is positive but for all practical purposes is zero, the long-run price elasticity given by  $\beta_1 + \beta_2$  is  $-0.20$ , and the natural annual rate of decline<sup>12</sup> in use per customer due to the adoption of new gas appliance capital equipment is 0.8 percent per year.

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<sup>11</sup> Although the dependent variables used to estimate the model are only for the months of October to March, the lagged independent real price variables represent actual lagged calendar month real prices. Hence, for the observation on weather normal use per household in October, the lagged real price (t-1) will be the September real price. Similarly, the lagged real price variable (t-12) for an October observation will be the real price of natural gas in October of the previous calendar year.

<sup>12</sup> If the coefficient on the time trend (T) in equation 4a and 4b is negative, it means there is an annual decline in natural gas weather normal use per customer. The percent decline will be equal to the coefficient on the time trend multiplied by 100%. For example, in Table 4 for the National sample, we see the coefficient on the

We also estimated equations (4a) and (4b) in a pooled regression where each LDC is given company specific intercepts for each of the six winter months in the sample, but all the slope coefficients were assumed to be the same across all LDCs. These estimates are shown in column two of Tables 4 and 5 below. Based on these estimates, we see the short-run price elasticity is  $-0.09$ , there is neither a practical nor a statistically significant<sup>13</sup> shift in the elasticity in post 2000, the long-run price elasticity given by  $\beta_1 + \beta_2$  is  $-0.18$ , and the natural annual rate of decline due to the adoption of new capital equipment is 1.0 percent per year in Table 5. Note the results did not indicate a change in price elasticity in the post-2000 time period in Table 4.

Although we did not obtain Iterative Bayes shrinkage estimates for each individual LDC, based on our experience we expect the average of these shrinkage estimates to fall between the pooled with LDC dummy results and the average of the individual OLS LDC regression results. We conclude therefore, that the short-run price elasticity of natural gas for the national sample lies between  $-0.09$  and  $-0.10$ , the long-run price elasticity is between  $-0.18$  and  $-0.20$ , and the natural annual rate of decline due to the adoption of new gas appliance capital equipment is between 0.7 percent and 1.0 percent per year. This natural annual rate of decline is consistent with a finding by an earlier AGA report on the decline in weather adjusted gas use per customer. See the AGA report “2004 AGA Energy Analysis: Patterns in Residential Natural Gas Consumption, 1980-2001”.

From Table 5 we see the total annual percent decline in use per household one year after a ten percent price increase<sup>14</sup> is between 2.7 percent and 2.8 percent.

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time trend variable is  $-0.011$  for the pooled with LDC dummy variables model. This means there is a  $0.011 \times 100\% = 1.1\%$  annual decline in natural gas weather normal use per customer.

<sup>13</sup> We base this conclusion on the statistical significance of the coefficient on the variable “ $\ln(\text{Price}_{t-1}) * D2000$ ” in Table 4. See Appendix D for a discussion of the meaning of the term “statistical significance” in statistical hypothesis testing.

<sup>14</sup> Since both the dependent and independent variables are in natural logarithms in equations (4a) and (4b), the coefficients on the two price variables are price elasticities, which give the percent decline in use per customer quantity demanded per one percent increase in price. Similarly, a negative coefficient on the time trend gives the proportionate decline in use per customer per one-year increase in time. To get the percent decline in use per customer one year after a 10 percent increase in price, we have:

$$\text{percent decline} = 10 * \text{coefficient on } P_{t-1} + 10 * \text{coefficient } P_{t-2} + 100 * \text{coefficient on time trend.}$$

**Table 4**  
**National Elasticity Model Estimates for Equation (4a)**  
**(t-stats in parentheses)**

<b>Variable</b>	<b>Pooled With LDC Fixed Effects Dummies</b>	<b>Average of Individual LDC OLS Estimates</b>
Ln(Price <sub>t-1</sub> )	-0.09 (-6.46)	-0.10
Ln(Price <sub>t-1</sub> )*D2000	0.0036 (0.97)	-0.0003
Ln(Price <sub>t-12</sub> )	-0.09 (-5.93)	-0.09
Annual Time Trend	-0.011 (-9.47)	-0.008
Rbar <sup>2</sup>	0.97	
Std. Error of Regression	0.115	
Mean of the Dependent Variable	1.183	
AIC	-1.403	
Schwarz Criterion	-0.906	
Number of Observations	3023	41

**Table 5**  
**National Elasticity Model Estimates for Equation (4b)**  
**(t-stats in parentheses)**

<b>Variable</b>	<b>Pooled With LDC Fixed Effects Dummies</b>	<b>Average of Individual LDC OLS Estimates</b>
Ln(Price <sub>t-1</sub> )	-0.09 (-6.44)	-0.10
Ln(Price <sub>t-12</sub> )	-0.09 (-5.92)	-0.10
Annual Time Trend	-0.010 (-12.25)	-0.007
Rbar <sup>2</sup>	0.97	
Std. Error of Regression	0.115	
Mean of the Dependent Variable	1.183	
AIC	-1.403	
Schwarz Criterion	-0.908	
Number of Observations	3023	41

## Regional Results

Figure 5 shows the normalized consumption of natural gas use per household by U.S. Census region for the AGA sample. There appears to be a decline over much of the sample in all nine Census Regions.

Figure 5  
Regional Weather Normal Consumption per Customer  
(Dth)

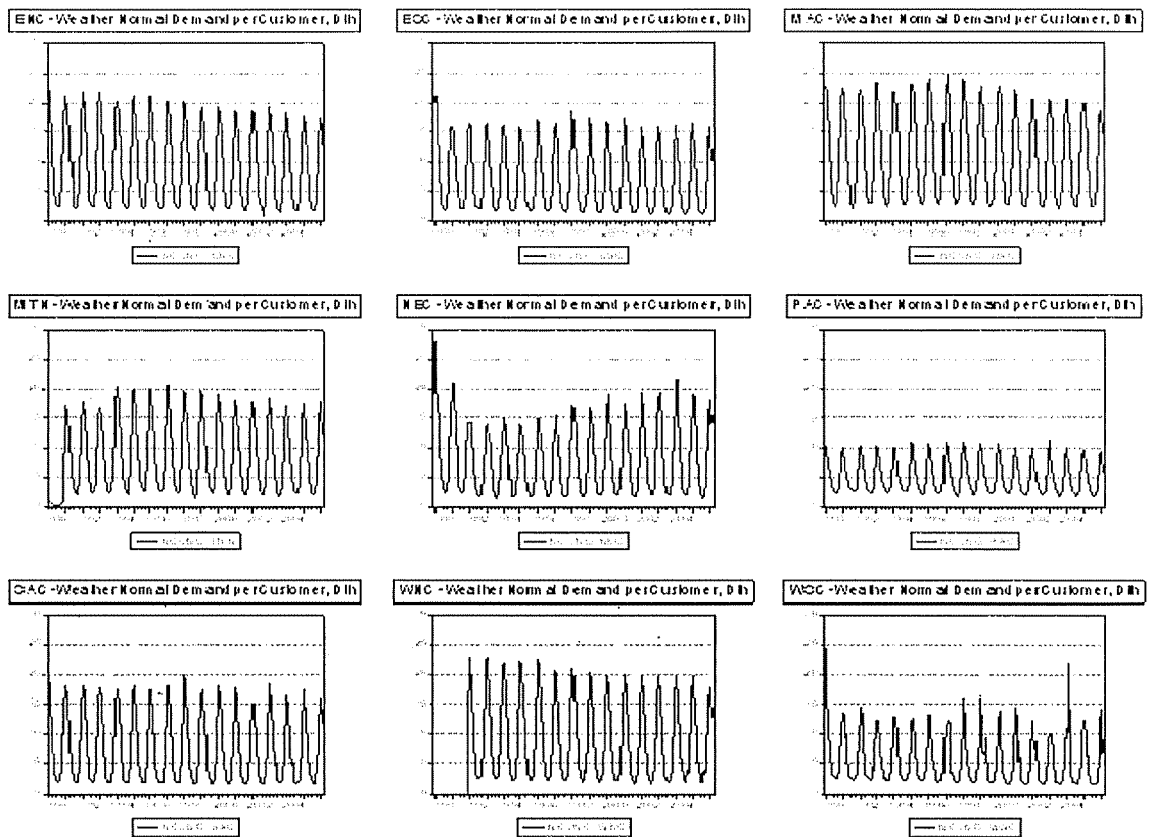
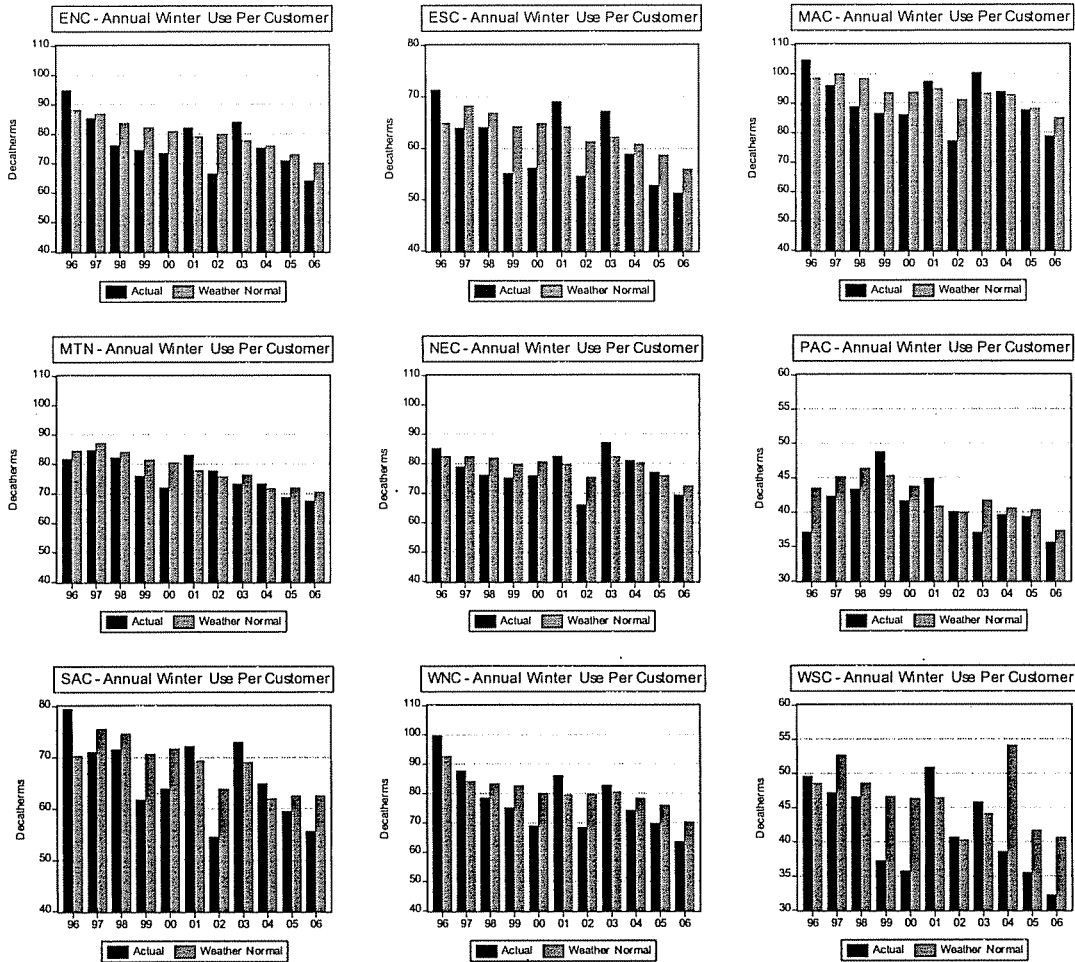


Figure 6 shows the actual and normalized winter season consumption for natural gas per customer by U.S. Census region for the AGA sample. Again, there is a decline over much of the sample in all regions.

**Figure 6**  
Regional Annual Winter Use per Customer  
(Dth)



Regional OLS Estimates

Tables 6A and 6B to Tables 14A and 14B give the estimates of equations (4a) and (4b) for each of the nine census Regions using data on the individual LDCs in each of the respective regions. For the most part, the regional results are similar to the national results, with some differences noted below.



## East North Central Region

The regression output for the ENC Region is given in Tables 6A and 6B. In Table 6A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 6B, the short-run elasticity is between -0.08 and -0.12, and is statistically significantly different from zero in the pooled model. The long-run elasticity is between -0.22 and -0.27. In the pooled regression, we observe a statistically significant annual declining rate of weather normal use per household demand of 1.0 percent. From Table 6B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.8 percent and 3.2 percent, which is close to the annual percent decline in the national sample.

**Table 6A**  
**ENC Regional Elasticity Model Estimates for Equation (4a)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.09 (-3.02)	-0.12
Ln(Price <sub>t-1</sub> )*D2000	0.005 (0.51)	-0.006
Ln(Price <sub>t-12</sub> )	-0.14 (-3.63)	-0.16
Annual Time Trend	-0.011 (-3.92)	0.0013
Rbar <sup>2</sup>	0.99	
Std. Error of Regression	0.064	
Mean of the Dependent Variable	1.319	
AIC	-2.569	
Schwarz Criterion	-2.200	
Number of Observations	195	3

**Table 6B**  
**ENC Regional Elasticity Model Estimates for Equation (4b)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.08 (-3.02)	-0.12
Ln(Price <sub>t-12</sub> )	-0.14 (-3.66)	-0.15
Annual Time Trend	-0.010 (-4.57)	-0.001
Rbar <sup>2</sup>	0.99	
Std. Error of Regression	0.063	
Mean of the Dependent Variable	1.319	
AIC	-2.578	
Schwarz Criterion	-2.225	
Number of Observations	195	3

## East South Central Region

The regression output for the ESC Region is given in Tables 7A and 7B. In Table 7A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 7B, the short-run elasticity is -0.06 when computed from the average of the individual LDC results and for all practical purposes is zero in the pooled regression. The long-run elasticity is between -0.01 and -0.12. In the pooled regression, we observe a statistically significant annual declining rate of weather normal use per household demand of 2.0 percent. From Table 7B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.0 percent and 2.1 percent, which is slightly lower than the annual percent decline in the national sample.

**Table 7A**  
**ESC Regional Elasticity Model Estimates for Equation (4a)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.007 (-0.12)	-0.08
Ln(Price <sub>t-1</sub> )*D2000	0.0169 (1.09)	0.02
Ln(Price <sub>t-12</sub> )	-0.03 (-0.47)	-0.06
Annual Time Trend	-0.023 (-4.92)	-0.016
Rbar <sup>2</sup>	0.97	
Std. Error of Regression	0.129	
Mean of the Dependent Variable	1.013	
AIC	-1.167	
Schwarz Criterion	-0.835	
Number of Observations	227	3

**Table 7B**  
**ESC Regional Elasticity Model Estimates for Equation (4b)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	0.012 (0.23)	-0.06
Ln(Price <sub>t-12</sub> )	-0.026 (-0.44)	-0.06
Annual Time Trend	-0.020 (-5.33)	-0.012
Rbar <sup>2</sup>	0.97	
Std. Error of Regression	0.129	
Mean of the Dependent Variable	1.013	
AIC	-1.170	
Schwarz Criterion	-0.853	
Number of Observations	227	3

## Middle Atlantic Region

The regression output for the MAC Region is given in Tables 8A and 8B. In Table 8A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 8B, the short-run elasticity is -0.13 when computed from the average of the individual LDC results, and is -0.10 in the pooled regression. The long-run elasticity is between -0.18 and -0.20. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per household demand of 1.3 percent. Table 8B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.5 percent and 3.3 percent, which is close to the annual percent decline in the national sample.

**Table 8A**  
**MAC Regional Elasticity Model Estimates for Equation (4a)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.11 (-2.35)	-0.12
Ln(Price <sub>t-1</sub> )*D2000	0.01 (1.21)	0.005
Ln(Price <sub>t-12</sub> )	-0.09 (-1.70)	-0.04
Annual Time Trend	-0.015 (-5.21)	-0.009
Rbar <sup>2</sup>	0.97	
Std. Error of Regression	0.100	
Mean of the Dependent Variable	1.508	
AIC	-1.681	
Schwarz Criterion	-1.325	
Number of Observations	465	6

**Table 8B**  
**MAC Regional Elasticity Model Estimates for Equation (4b)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.10 (-2.24)	-0.13
Ln(Price <sub>t-12</sub> )	-0.10 (-1.77)	-0.05
Annual Time Trend	-0.013 (-5.80)	-0.007
Rbar <sup>2</sup>	0.97	
Std. Error of Regression	0.100	
Mean of the Dependent Variable	1.508	
AIC	-1.682	
Schwarz Criterion	-1.335	
Number of Observations	465	6

## Mountain Region

The regression output for the MTN Region is given in Tables 9A and 9B. In Table 9A, we estimate shift of  $-0.035$  in the short-run elasticity in post 2000 and beyond. According to equation (4b) in Table 9B, the short-run elasticity is  $-0.11$  when computed from the average of the individual LDC results and is  $-0.07$  and statistically significant in the pooled regression. The long-run elasticity is between  $-0.10$  and  $-0.19$ . In the pooled regression we observe a statistically significant annual declining rate of weather normal use per household demand of 0.9 percent. In Table 9B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 1.9 percent and 2.8 percent, which in the pooled regression (1.9 percent) is slightly lower than the annual percent decline in the national sample.

**Table 9A**  
**MTN Regional Elasticity Model Estimates for Equation (4a)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.014 (-0.52)	-0.08
Ln(Price <sub>t-1</sub> )*D2000	-0.035 (-4.19)	-0.02
Ln(Price <sub>t-12</sub> )	-0.018 (-0.75)	-0.07
Annual Time Trend	-0.004 (-2.47)	-0.007
Rbar <sup>2</sup>	0.99	
Std. Error of Regression	0.060	
Mean of the Dependent Variable	1.262	
AIC	-2.700	
Schwarz Criterion	-2.353	
Number of Observations	298	4

**Table 9B**  
**MTN Regional Elasticity Model Estimates for Equation (4b)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.07 (-2.73)	-0.11
Ln(Price <sub>t-12</sub> )	-0.03 (-1.33)	-0.08
Annual Time Trend	-0.009 (-6.22)	-0.009
Rbar <sup>2</sup>	0.99	
Std. Error of Regression	0.060	
Mean of the Dependent Variable	1.262	
AIC	-2.644	
Schwarz Criterion	-2.309	
Number of Observations	298	4

## New England Region

The regression output for the NEC Region is given in Tables 10A and 10B. In Table 10A, we estimate a statistically significant shift in the short-run price elasticity in the post 2000 year period, although in this case it is a shift that lowers the short-run price elasticity and is not practically significant with only 0.015 decrease. According to equation (4b) in Table 10B, the short-run elasticity is -0.08 when computed from the average of the individual LDC results and is also -0.08 and statistically significant in the pooled regression. The long-run elasticity is between -0.25 and -0.28. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer demand of 0.4 percent. Table 10B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.9 percent and 3.0 percent, which is close to the annual percent decline in the national sample.

**Table 10A**  
**NEC Regional Elasticity Model Estimates for Equation (4a)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.09 (-3.34)	-0.09
Ln(Price <sub>t-1</sub> )*D2000	0.015 (2.44)	0.01
Ln(Price <sub>t-12</sub> )	-0.17 (-5.06)	-0.20
Annual Time Trend	-0.008 (-4.24)	-0.005
Rbar <sup>2</sup>	0.97	
Std. Error of Regression	0.096	
Mean of the Dependent Variable	1.307	
AIC	-1.767	
Schwarz Criterion	-1.413	
Number of Observations	660	8

**Table 10B**  
**NEC Regional Elasticity Model Estimates for Equation (4b)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.08 (-2.86)	-0.08
Ln(Price <sub>t-12</sub> )	-0.17 (-5.00)	-0.20
Annual Time Trend	-0.004 (-3.73)	-0.002
Rbar <sup>2</sup>	0.97	
Std. Error of Regression	0.097	
Mean of the Dependent Variable	1.307	
AIC	-1.760	
Schwarz Criterion	-1.412	
Number of Observations	660	8

## Pacific Region

The regression output for the PAC Region is given in Tables 11A and 11B. In Table 11A, we estimate a statistically significant shift in the short-run price elasticity in the post 2000 year period, although from a practical point of view this decline is small with an impact of only 0.02. According to equation (4b) in Table 11B, the short-run elasticity is -0.07 when computed from the average of the individual LDC results and is also -0.07 and statistically significant in the pooled regression. The long-run elasticity is between -0.12 and -0.15. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 0.8 percent. In Table 11B, we see the total annual percent decline in use per customer one year after a ten percent price increase of 2.0 percent, which is lower than the annual percent decline in the national sample.

**Table 11A**  
**PAC Regional Elasticity Model Estimates for Equation (4a)**  
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.04 (-1.29)	-0.03
Ln(Price <sub>t-1</sub> )*D2000	-0.02 (-2.13)	-0.02
Ln(Price <sub>t-12</sub> )	-0.05 (-1.66)	-0.07
Annual Time Trend	-0.005 (-1.96)	-0.004
Rbar <sup>2</sup>	0.98	
Std. Error of Regression	0.072	
Mean of the Dependent Variable	0.910	
AIC	-2.314	
Schwarz Criterion	-1.929	
Number of Observations	258	4

**Table 11B**  
**PAC Regional Elasticity Model Estimates for Equation (4b)**  
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.07 (-2.61)	-0.07
Ln(Price <sub>t-12</sub> )	-0.05 (-1.83)	-0.08
Annual Time Trend	-0.008 (-3.87)	-0.005
Rbar <sup>2</sup>	0.98	
Std. Error of Regression	0.073	
Mean of the Dependent Variable	0.910	
AIC	-2.302	
Schwarz Criterion	-1.931	
Number of Observations	258	4

## South Atlantic Region

The regression output for the SAC Region is given in Tables 12A and 12B. In Table 12A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 12B, the short-run elasticity is -0.11 when computed from the average of the individual LDC results and is -0.12 and statistically significant in the pooled regression. The long-run elasticity is between -0.24 and -0.29. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 0.8 percent. Table 12B, we see the total annual percent decline in use per customer one year after a ten percent price increase is between 3.4 percent to 3.7 percent, which is higher than the annual percent decline in the national sample.

**Table 12A**  
**SAC Regional Elasticity Model Estimates for Equation (4a)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.115 (-3.09)	-0.10
Ln(Price <sub>t-1</sub> )*D2000	-0.002 (-0.15)	-0.005
Ln(Price <sub>t-12</sub> )	-0.17 (-4.16)	-0.13
Annual Time Trend	-0.008 (-2.58)	-0.009
Rbar <sup>2</sup>	0.97	
Std. Error of Regression	0.109	
Mean of the Dependent Variable	1.218	
AIC	-1.509	
Schwarz Criterion	-1.146	
Number of Observations	280	4

**Table 12B**  
**SAC Regional Elasticity Model Estimates for Equation (4b)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.12 (-3.30)	-0.11
Ln(Price <sub>t-12</sub> )	-0.17 (-4.18)	-0.13
Annual Time Trend	-0.008 (-3.76)	-0.010
Rbar <sup>2</sup>	0.97	
Std. Error of Regression	0.108	
Mean of the Dependent Variable	1.218	
AIC	-1.516	
Schwarz Criterion	-1.166	
Number of Observations	280	4

## West North Central Region

The regression output for the WNC Region is given in Tables 13A and 13B. In Table 13B, we estimate a statistically significant shift in the short-run price elasticity in the post 2000 year period, although it is a shift that lowers the short-run price elasticity by only -0.014 and from a practical point of view is not significant. According to equation (4b) in Table 13B, the short-run elasticity is -0.08 when computed from the average of the individual LDC results and is -0.09 and statistically significant in the pooled regression. The long-run elasticity is between -0.13 and -0.15. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 1.1 percent. In Table 13B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.5 percent and 2.6 percent, which is close to the annual percent decline in the national sample.

**Table 13A**  
**WNC Regional Elasticity Model Estimates for Equation (4a)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.10 (-5.19)	-0.09
Ln(Price <sub>t-1</sub> )*D2000	0.014 (1.98)	0.01
Ln(Price <sub>t-12</sub> )	-0.06 (-2.62)	-0.05
Annual Time Trend	-0.014 (-5.48)	-0.014
Rbar <sup>2</sup>	0.99	
Std. Error of Regression	0.048	
Mean of the Dependent Variable	1.314	
AIC	-3.141	
Schwarz Criterion	-2.765	
Number of Observations	190	3

**Table 13B**  
**WNC Regional Elasticity Model Estimates for Equation (4b)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.09 (-4.78)	-0.08
Ln(Price <sub>t-12</sub> )	-0.06 (-2.69)	-0.05
Annual Time Trend	-0.011 (-5.35)	-0.012
Rbar <sup>2</sup>	0.99	
Std. Error of Regression	0.048	
Mean of the Dependent Variable	1.314	
AIC	-3.129	
Schwarz Criterion	-2.770	
Number of Observations	190	3



## West South Central Region

The regression output for the WSC Region is given in Tables 14A and 14B. In Table 14A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 14B, the short-run elasticity is -0.14 when computed from the average of the individual LDC results and is -0.13 and statistically significant in the pooled regression. The long-run elasticity is -0.16 in both the pooled regression and when computed as the average of the individual LDC OLS estimates. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 1.6 percent. In Table 14B, we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.9 percent and 3.2 percent, which is close to the annual percent decline in the national sample.

**Table 14A**  
**WSC Regional Elasticity Model Estimates for Equation (4a)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.12 (-1.71)	-0.13
Ln(Price <sub>t-1</sub> )*D2000	-0.008 (-0.48)	-0.009
Ln(Price <sub>t-12</sub> )	-0.03 (-0.40)	-0.02
Annual Time Trend	-0.015 (-2.52)	-0.01
Rbar <sup>2</sup>	0.92	
Std. Error of Regression	0.198	
Mean of the Dependent Variable	0.722	
AIC	-0.318	
Schwarz Criterion	0.048	
Number of Observations	450	6

**Table 14B**  
**WSC Regional Elasticity Model Estimates for Equation (4b)**  
**(t-stats in parentheses)**

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln(Price <sub>t-1</sub> )	-0.13 (-1.87)	-0.14
Ln(Price <sub>t-12</sub> )	-0.03 (-0.40)	-0.02
Annual Time Trend	-0.016 (-3.79)	-0.013
Rbar <sup>2</sup>	0.92	
Std. Error of Regression	0.198	
Mean of the Dependent Variable	0.722	
AIC	-0.322	
Schwarz Criterion	0.034	
Number of Observations	450	6

### Shrinkage Estimates

We also estimate equation (4a) and (4b) with a type of shrinkage estimator, time series data on the Nine Census Regions, aggregated over the respective LDCs in each region. We will apply the Stein rule estimator discussed above in the sub-section on Shrinkage Estimators. The advantage of shrinkage estimators is that they allow for some similarity among the slope coefficients without constraining them to be exactly the same as in the case of pooled estimates.

Using aggregate regional data, Table 15 below gives the pooled fixed effects estimates of equation (4b) and the average of the individual regional coefficient estimates. These estimates are similar to the estimates presented in Table 5B based on individual LDC data. Note that in Table 5B the impact of a 10 percent price increase was a 2.8 percent decline in use per customer one year later. Using regional aggregate data we see the impact of a ten percent price increase is a similar 2.9 percent decline in use per customer one year later.

**Table 15**  
**Regional Elasticity Model Estimates using aggregate data for Equation (4b)**  
**(t-stats in parentheses)**

Variable	Pooled With Regional Dummies	Average of Individual Regions
Ln(Price <sub>t-1</sub> )	-0.12 (-3.4)	-0.10
Ln(Price <sub>t-12</sub> )	-0.06 (-1.63)	-0.08
Annual Time Trend	-0.011 (-3.72)	-0.011
Rbar <sup>2</sup>	0.98	
Std. Error of Regression	0.094	
Mean of the Dependent Variable	12.14	
AIC	-1.79	
Schwarz Criterion	-1.34	
Number of Observations	540	9

Tables 16 to 24 below present the Stein Shrinkage coefficient estimates of equation (4b) using aggregate regional data. In this case, the shrinkage results are very close to the individual OLS estimates for each Region since  $F = 0.86$  and  $c = 0.04$  since  $T=60$ . Plugging into equation (5) we get:

$$\tilde{\beta}_i = 0.95\hat{\beta}_i + 0.05\hat{\beta}_p, \quad (7)$$

### East North Central Region

Table 16 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the ENC Region is -0.047 and -0.122, and the annual time trend shows a declining annual rate of 1.7 percent.

**Table 16**

<b>ENC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b</b>			
<b>Variable</b>	<b>OLS on Individual Regional Data</b>		<b>Shrinkage Estimator</b>
	Estimate	t-stat	
<b>Ln(Price<sub>t-1</sub>)</b>	-0.043	-0.349	-0.047
<b>Ln(Price<sub>t-12</sub>)</b>	-0.076	-0.544	-0.075
<b>Annual Time Trend</b>	-0.017	-1.530	-0.017
<b>Number of Observations</b>	60		

### East South Central Region

Table 17 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for East South Central is -0.030 and -0.085, and the annual time trend shows a declining annual rate of 1.8 percent.

**Table 17**

<b>ESC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b</b>			
<b>Variable</b>	<b>OLS on Individual Regional Data</b>		<b>Shrinkage Estimator</b>
	estimate	t-stat	
<b>Ln(Price<sub>t-1</sub>)</b>	-0.026	-0.180	-0.030
<b>Ln(Price<sub>t-12</sub>)</b>	-0.055	-0.337	-0.055
<b>Annual Time Trend</b>	-0.018	-1.270	-0.018
<b>Number of Observations</b>	60		

### Middle Atlantic Region

Table 18 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the Middle Atlantic Region is -0.164 and -0.46, and the annual time trend shows a declining annual rate of 0.6 percent.

**Table 18**

<b>MAC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b</b>			
<b>Variable</b>	<b>OLS on Individual Regional Data</b>		<b>Shrinkage Estimator</b>
	estimate	t-stat	
<b>Ln(Price<sub>t-1</sub>)</b>	-0.167	-1.198	-0.164
<b>Ln(Price<sub>t-12</sub>)</b>	-0.309	-1.887	-0.296
<b>Annual Time Trend</b>	0.006	0.633	0.006
<b>Number of Observations</b>	60		

### Mountain Region

Table 19 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the Mountain Region is -0.058 and -0.076, and the annual time trend shows a declining annual rate at of 2.22 percent.

**Table 19**

<b>MTN - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b</b>			
<b>Variable</b>	<b>OLS on Individual Regional Data</b>		<b>Shrinkage Estimator</b>
	estimate	t-stat	
<b>Ln(Price<sub>t-1</sub>)</b>	-0.055	-0.675	-0.058
<b>Ln(Price<sub>t-12</sub>)</b>	0.022	0.263	0.018
<b>Annual Time Trend</b>	-0.022	-2.767	-0.022
<b>Number of Observations</b>	60		

## New England Region

Table 20 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the New England Region is -0.074 and -0.364, and the annual time trend shows a declining annual rate of 0.3 percent.

**Table 20**

<b>NEC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b</b>			
<b>Variable</b>	<b>OLS on Individual Regional Data</b>		<b>Shrinkage Estimator</b>
	Estimate	t-stat	
<b>Ln(Price<sub>t-1</sub>)</b>	-0.072	-0.537	-0.074
<b>Ln(Price<sub>t-12</sub>)</b>	-0.302	-1.767	-0.290
<b>Annual Time Trend</b>	-0.003	-0.384	-0.003
<b>Number of Observations</b>	60		

## Pacific Region

Table 21 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the Pacific Region is -0.089 and -0.179, and the annual time trend shows a declining annual rate of 1.0 percent.

**Table 21**

<b>PAC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b</b>			
<b>Variable</b>	<b>OLS on Individual Regional Data</b>		<b>Shrinkage Estimator</b>
	estimate	t-stat	
<b>Ln(Price<sub>t-1</sub>)</b>	-0.087	-1.066	-0.089
<b>Ln(Price<sub>t-12</sub>)</b>	-0.092	-1.194	-0.090
<b>Annual Time Trend</b>	-0.010	-1.157	-0.010
<b>Number of Observations</b>	60		

### South Atlantic Region

Table 22 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the South Atlantic Region is -0.182 and -0.327, and the annual time trend shows a declining annual rate of 1.9 percent.

**Table 22**

<b>SAC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b</b>			
<b>Variable</b>	<b>OLS on Individual Regional Data</b>		<b>Shrinkage Estimator</b>
	estimate	t-stat	
<b>Ln(Price<sub>t-1</sub>)</b>	-0.185	-1.747	-0.182
<b>Ln(Price<sub>t-12</sub>)</b>	0.156	1.371	0.145
<b>Annual Time Trend</b>	-0.019	-1.989	-0.019
<b>Number of Observations</b>	60		

### West North Central Region

Table 23 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the West North Central Region is -0.088 and -0.120, and the annual time trend shows a declining annual rate of 0.90 percent.

**Table 23**

<b>WNC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b</b>			
<b>Variable</b>	<b>OLS on Individual Regional Data</b>		<b>Shrinkage Estimator</b>
	estimate	t-stat	
<b>Ln(Price<sub>t-1</sub>)</b>	-0.086	-0.966	-0.088
<b>Ln(Price<sub>t-12</sub>)</b>	-0.031	-0.355	-0.032
<b>Annual Time Trend</b>	-0.009	-1.053	-0.009
<b>Number of Observations</b>	60		

## West South Central Region

Table 24 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the West South Central Region is -0.209 and -0.258, and the annual time trend shows a declining annual rate of 1.1 percent.

**Table 24**

<b>WSC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b</b>			
<b>Variable</b>	<b>OLS on Individual Regional Data</b>		<b>Shrinkage Estimator</b>
	estimate	t-stat	
<b>Ln(Price<sub>t-1</sub>)</b>	-0.214	-1.719	-0.209
<b>Ln(Price<sub>t-12</sub>)</b>	-0.049	-0.368	-0.049
<b>Annual Time Trend</b>	-0.011	-0.946	-0.011
<b>Number of Observations</b>	60		

Our overall assessment of the regional models is that individual coefficients vary<sup>15</sup> greatly across the nine regional models and are often insignificant. This is due to the small sample sizes relative to the national sample, multicollinearity between the two lagged prices, and to some extent multicollinearity with the time trend as well. Yet the average impact of a 10 percent price increase on use per household is remarkably stable and negative across all nine Census Regions in the pooled regressions using individual LDC data. This total decline after a 10 percent price increase for the nine Census Regions is roughly centered on the national impact of a 2.8 percent decline in weather normal use per customer; with the Mountain Region having a 1.9 percent impact at the low end of the range and the South Atlantic Region having a 3.7 percent impact at the high end of the range.

<sup>15</sup> There may be differences in shell efficiency and new home construction and LDC sponsored energy conservations programs across regions that would lead to some heterogeneity in coefficient estimates across the nine census regions. We feel the iterative Bayes shrinkage estimator could remove much of the inconsistency between the national and regional coefficient estimates in a follow up study.

## Section 5: Summary of Results and Policy Implications

This research project was initiated to examine the decline in residential natural gas consumption since 2000 and to determine whether there had been a change in the response by residential consumers to higher (and more volatile) natural gas prices. The data that were collected and analyzed support two important findings and a general rule of thumb. This rule appears to capture consumers' winter price sensitive consumption behavior reasonably well across the LDCs and Census regions.

First, consumption is strongly influenced by seasonal heating needs, response to price change, and the efficiency changes in appliances and home shell efficiency coupled with conservation behavior by consumers. While the separate efficiency and conservation effects due to appliance and housing shell turnover are difficult to disentangle in the current sample, they appear to be discernable from the price effects. Table 25 gives a summary of the national and separate regional price and naturally occurring time trend effects found in this study.

Second, we could not find evidence supporting an appreciable change in the short-run price elasticity of natural gas consumption in the post year 2000 period.

**Table 25**  
**Summary of National and Regional**  
**Natural Gas Price Estimates<sup>16</sup>**

Region	Short-run elasticity	Long-run elasticity*	Annual Time Trend	Total Response to a 10% Price Increase**
National	-0.09	-0.18	-1.0%	-2.8%
East North Central	-0.08	-0.22	-1.0%	-3.2%
East South Central	-0.01	-0.01	-2.0%	-2.1%
Middle Atlantic	-0.10	-0.20	-1.3%	-3.3%
Mountain	-0.07	-0.10	-0.9%	-1.9%
New England	-0.08	-0.25	-0.4%	-2.9%
Pacific	-0.07	-0.12	-0.8%	-2.0%
South Atlantic	-0.12	-0.29	-0.8%	-3.7%
West North Central	-0.09	-0.15	-1.1 %	-2.6%
West South Central	-0.13	-0.16	-1.6%	-3.2%

\* Cumulative: includes impacts of short-run elasticities

\*\* The total response to a 10 percent price increase is the sum of the long-run elasticity and the annual time trend effect.

The results from the price elasticity estimates and the combination of efficiency and conservation estimates are able to explain the post 2000 winter consumption per customer actual experience. Normal winter season natural gas use per household in the US has declined

<sup>16</sup> Estimates obtained from the "fixed effects" pooled regression.



about 13.1 percent between 2000 and 2006. There has been an increase in real natural gas prices of 44 percent for the same time period, which according to our analysis would lead to approximately a 7.9 percent (0.18 x 44 percent) decline in use per customer by the year 2006. In addition to this 7.9 percent price induced decline in weather normal use per household, there would be an additional 6.0 percent (6 x 1.0 percent) decline because of the natural annual rate of turnover of old gas appliances to newer more efficient appliances. Hence, our analysis predicts a decline of 13.9 percent over the six-year period, which is very close to the actual decline of 13.1 percent.

<i>Overall decline</i>		<i>Price Effect</i>		<i>Conservation and</i>
<i>in Winter Gas Use</i>	=	<i>Elasticity with</i>	+	<i>Turnover to More</i>
<i>per Customer</i>		<i>Price Increase</i>		<i>Efficient Appliances</i>
13.9%	=	0.18 x 44%	+	6 x 1.0%
	=	7.9%	+	6.0%

In the expression above, the left hand term is the overall declining rate of winter gas use per customer, the first term on the right hand side is the price effect reflecting elasticity with price increase, and the second term the effect from conservation and turnover to more efficient appliances that occurs naturally every year with or without a price increase.

This proposed rule of thumb suggests that twelve months after a 10 percent increase in natural gas prices at the national level, there will be nearly a 3 percent decline in natural gas use per customer. This 3 percent decline is comprised of about a 1 percent drop in gas use with the current capital stock, about a 1 percent drop in use per customer because households respond to the higher gas prices by buying more efficient appliances, and a 1 percent drop in gas usage per customer due to the natural turnover to more efficient gas appliances each year. This rule of thumb will vary by LDC because they are heterogeneous in terms of weather, housing stocks, and standards of living.

It should be noted that the 1 percent price-induced drop with the current capital stock is what economist refer to as the elasticity of “short-run” demand. This refers to customers “turning down the thermostat”. There is a second 1 percent price induce drop in use per customer that occurs one year later due to consumers buying more efficient appliances and increasing the tightness of the home. The price elasticity in the “long-run” is the sum of the short-run demand elasticity and the additional changes that occur to quantity demanded one year later because of natural gas price impacts on consumer choice of appliance and home thermal shell efficiency.

The heightened conservation behavior by consumers is partly due to the many government and utility programs that currently exist to encourage residential consumers to save energy:

- The federal government encourages conservation through weatherization programs funded by the Low-Income Household Energy Assistance Program (LIHEAP), tax credits for purchase of efficient appliances and shell improvements, and consumer education on the importance of saving energy.

- State and local governments also encourage efficiency through similar programs
- Many utilities provide rebates, incentives, and assistance to their customers to improve use of energy. For example, electric and natural gas utilities provided more than \$140 million in 2005 to assist low-income customers to weatherize their homes {Source: <http://liheap.ncat.org/tables/FY2005/05stlvtb.htm> }

From a planning and policy perspective, even if gas prices do not increase in a given year, there will still be approximately a 1 percent fall in gas usage per household in the following year. This is driven by the historical forces related to the natural turnover of old appliances to the more efficient appliances that are available on the market each year. The annual time trend impacts will vary somewhat by LDC, because of regional differences in weather, appliance stocks, housing shell efficiency, demographic and economic characteristics.

There is a caveat. We cannot address whether the phenomenon will continue at the same rate for the long-term. Further gains in efficiency in absolute and relative terms may or may not have the same impact as they did previously. This is an issue for more detailed engineering studies on the efficiency of appliances and housing shells and economic research on the change in conservation habits of consumers for energy use and winter season comfort levels. We would note, however, that legislative and regulatory pressure for greater efficiency is likely to increase as climate change becomes a more pronounced national and international priority.

The policy implications of the 13.1 percent decline since 2000 are significant. First, regulators must recognize these trends and allow rate structures to incorporate these variations. Second, the natural turnover of appliances and increases in shell efficiency from new construction will result in continued conservation, regardless of price changes, impacting utility operations. Third, even if future gas prices remain constant or even decrease, the appliance and home shell efficiency gains achieved in prior years will not be reversed.

#### Suggestions for Future Research

As with any study, there is room for future research. Suggestions for future research are the following:

- Obtain data from Natural Gas Companies that did not participate in the initial study.
- Try different specifications of the model.
- Use the Iterative Bayes Shrinkage Estimation Technique to get individual LDC parameter estimates.
- Consider the impact of competition from the electric utility industry.

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## Appendix A: Construction of Weather-Normalized Series for Use per Customer

Step 1. Calculate the ratio of HDDN to HDD (normal heating degree days / actual heating degree days.) this is referred to as the weather normalization factor

Step 2. Construct a proxy for base natural gas consumption per customer for each “year”. Calculate the average of July and August for each year.

Step 3. Subtract the base consumption from Actual consumption for the September through June for the next 10 months. Refer to this as “heating” consumption. Example: the average of July and August 1999 will be subtracted from September 1999 through June 2000. Retain the actual values for July and August 1999 in the “heating” consumption variable.

Step 4. Calculate the weather normal consumption per customer series. Multiply the “heating” consumption variable by the weather normalization factor. Intuitively, a very cold winter will have relatively high levels of consumption. The very cold weather means that the denominator in the weather normalization factor is large relative to the normal HDD. Multiplying the large consumption variable times the factor, which is less than one, will bring back or reduce consumption towards the normal “heating” consumption level.

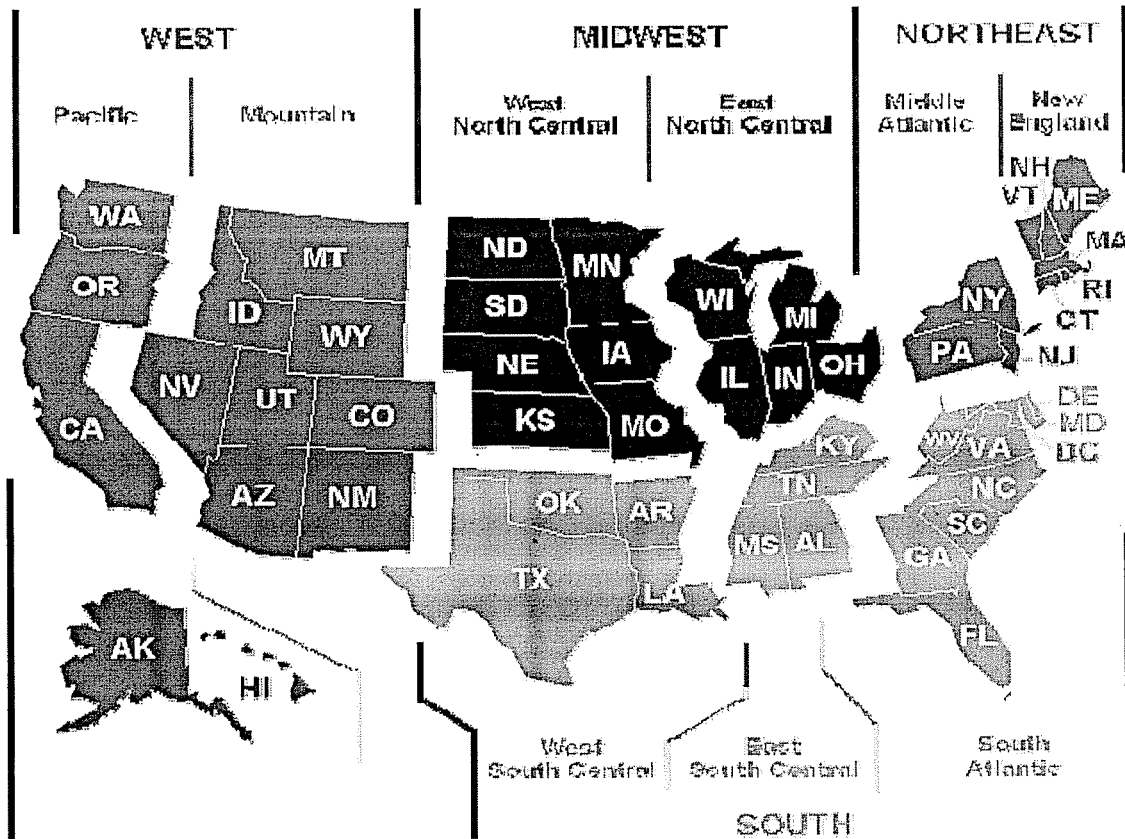
Step 5. Add the base consumption per customer back into the September through June normal heating consumption levels.

Variable list omitting the region identifiers:

HDD	- Actual Heating Degree Days
HDDN	- Normal Heating Degree Days
CUNG	- Natural Gas Use per Customer per Month
ZSAJQUS	- Days per Month
WNF	- Weather Normalization Factor
	$WNF = HDDN / HDD$
Base	- Average of July and August in a year
HCUNG	- “Heating” Natural Gas Use per Customer per Month
	$HCUNG = CUNG - Base$
NCUNG	- “Normalized” Natural Gas Use per Customer per Month
	$NCUNG = ( HCUNG * WNF ) + Base$
CUNGW	- Actual Daily Natural Gas Use per Customer per Month
	$CUNGW = CUNG / ZSAJQUS$
NCUNGW	- “Normalized” Natural Gas Use per Customer per Month
	$NCUNGW = NCUNG / ZSAJQUS$

## Appendix B: U.S. Census Regions

Figure B.1  
U.S. Census Region Map



Source: U.S. Dept. of Energy [http://www.eia.doe.gov/emeu/cbecs/census\\_maps.html](http://www.eia.doe.gov/emeu/cbecs/census_maps.html)



**Table B.1**  
U.S. Census Region Definitions

<u>Division 1</u>	<u>Division 3</u>	<u>Division 5</u>	<u>Division 7</u>	<u>Division 9</u>
<b>New England</b>	<b>East North Central</b>	<b>South Atlantic</b>	<b>West South Central</b>	<b>Pacific</b>
Connecticut	Illinois	Delaware	Arkansas	Alaska
Maine	Indiana	District of Columbia	Louisiana	California
Massachusetts	Michigan	Florida	Oklahoma	Hawaii
New Hampshire	Ohio	Georgia	Texas	Oregon
Rhode Island	Wisconsin	Maryland		Washington
Vermont		North Carolina	<b><u>Division 8</u></b>	
	<b><u>Division 4</u></b>	South Carolina	<b>Mountain</b>	
<b><u>Division 2</u></b>	<b>West North Central</b>	Virginia	Arizona	
<b>Middle Atlantic</b>	Iowa	West Virginia	Colorado	
New Jersey	Kansas		Idaho	
New York	Minnesota	<b><u>Division 6</u></b>	Montana	
Pennsylvania	Missouri	<b>East South Central</b>	Nevada	
	Nebraska	Alabama	New Mexico	
	North Dakota	Kentucky	Utah	
	South Dakota	Mississippi	Wyoming	
		Tennessee		

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

**U.S. Census Region Pneumonic**

ENC	East North Central
ESC	East South Central
MAC	Middle Atlantic
MTN	Mountain
NEC	New England
PAC	Pacific
SAC	South Atlantic
WNC	West North Central
WSC	West South Central

## Appendix C: Literature Review<sup>17</sup>

There are many studies on the price and income elasticities of residential energy goods in general, and of residential natural gas demand in particular. Table 1 below lists some of these studies, along with the short-run and long-run estimates. See Dahl and Roman (2004) and Dahl (2005) for recent surveys of energy elasticity demand estimates. Other surveys of energy demand price elasticity estimates are Taylor (1975 and 1977), Bohi (1981), Bohi and Zimmerman (1984), Al-Sahlawi (1989), Dahl (1993), and Espy and Espy (2004). Common drawbacks of these studies are: (1) they do not include data that contain the recent increases in residential natural gas prices, (2) they do not focus on the winter season demand, (3) they do not contain company level data across the entire US, and (4) most do not allow for a non-price related decline in use per customer that occurs automatically as consumers replace old inefficient appliances with newer more efficient ones.

The AGA study overcomes the missing elements in the existing literature by looking at individual company level winter season monthly data from all nine US Census Regions over the period 1981 to 2006. Also, the AGA study allows for a naturally occurring decline in use per customer that results from the replacement of old inefficient gas appliances with newer more efficient models.

There have been many papers written that estimate the price elasticity of residential demand for natural gas. A partial list of these papers is given in the references section. Estimates of short-run price elasticity range from as low as  $-0.05$  in Beirlein, Dunn and McConnon (1981) to as high as  $-0.68$  in Barnes, Gillingham & Hagemann (1982). For long-run price elasticity estimates the range of estimates is even higher, with the low being  $-0.017$  in Hewlett (1977) to as high as  $-3.42$  in Beirlein, Dunn and McConnon (1981).

It is fair to say there is no real consensus on residential natural gas price elasticity demand estimates. For overall residential energy demand in general, the median estimate of short-run price elasticity is about  $-0.2$ , with the long-run dynamic models with lagged dependent variables yielding a median estimate of about  $-0.48$ . For natural gas in particular, using EIA state level aggregate data, Maddala, et. al. (1997) estimate the average short-run price elasticity of natural gas is  $-0.1$  and the long-run price elasticity of residential natural gas demand is  $-0.27$ .

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<sup>17</sup> This appendix benefited from discussions and on-going research by Professor Carol Dahl, the Colorado School of Mines, Golden, Colorado. All errors are ours.

**Table C.1**  
**Residential Price Elasticity Estimates**

Authors	Data	Estimation Method	Short-run	Long-run
Balestra & Nerlove (1966)	Pooled: 36 States for 1957-62)	GLS(EC)	NA	-0.63
Jaskow & Baughman (1976)	Pooled: 48 States for 1968-72	OLS	-0.15	-1.01
Berndt & Watkins (1977)	Pooled: Ontario and British Columbia for 1959-74	Maximum Likelihood	-0.15	-0.69
Hewlett (1977)	Cross Section: New York State household survey	OLS	NA	-0.45
Hewlett (1977)	Pooled: New York State customer survey for 1976 and 1977.	OLS	NA	-0.17
Beirlein, Dunn & McConnon (1981)	Pooled: 9 States for 1967-77	OLS	-0.23	-2.90
		GLS (EC)	-0.23	-2.96
		GLS (EC-SUR)	-0.05	-3.42
Barnes, Gillingham & Hagemann (1982)	Pooled: 10,000 households in 23 US cities. Quarterly data for 1972-73.	IV	-0.68	NA
Green & Gilbert (1983)	Cross-Sectional: non-poverty homeowners and poverty homeowners	OLS	NA	-1.25
		OLS	NA	-1.09
Blattenberger, Taylor, & Rennhack (1983)	Pooled: 48 states for 1961-74	GLS (EC)	-0.32	-0.39
Green, Salley, Grass & Osei (1986)	Pooled: between 6 and 7 thousand households for 1974 to 1979.	OLS	-0.16	NA

## Appendix D: Statistical Hypothesis Testing

The practical question that is addressed in statistical hypothesis testing concerns the relative strength of some “treatment”; such as does price have an impact on weather normal use per household natural gas demand. The question addressed might be: Do the data contained in the sample present sufficient evidence that increases in price lead to a lower use per household natural gas demand?

The reasoning employed in testing a hypothesis bears a striking resemblance to the procedure used in a court trial. In trying a person for a crime, the court assumes the accused innocent until proven guilty. The prosecution collects and presents all the available evidence in an attempt to contradict the “not guilty” hypothesis and hence to obtain a conviction. However, if the prosecution fails to disprove the “not guilty” hypothesis, this does not prove that the accused is “innocent” but merely that there is not sufficient evidence to conclude that the accused is “guilty”.

The statistical problem in this study portrays “natural gas price” as the accused. The hypothesis to be tested, called the **null hypothesis**, is that price does not negatively impact the weather normal use per household natural gas demand. The evidence in this case is contained in the sample drawn from the population of LDCs who supply this demand. The researcher, playing the role of the prosecutor, believes that an **alternative hypothesis** is true - namely, that natural gas price does have a negative impact on natural gas use per household demand. Hence, the researcher attempts to use the evidence contained in the sample to reject the null hypothesis (no impact of natural gas price on natural gas demand) and thereby to support the alternative hypothesis, the contention that price does in fact inversely impact natural gas demand.

The statistician will calculate a test statistic from the information contained in the sample. All possible values the test statistic may assume are divided into two groups – one called the rejection region and the other the acceptance region. After the sample is collected the test statistic is calculated and observed. If the test statistic takes on a value in the rejection region, the null hypothesis is rejected. Otherwise, one fails to reject the null hypothesis.

You will notice that the researcher is faced with two possible types of errors. On the one hand, the researcher might reject the null hypothesis when it is true, and falsely conclude that natural gas price does negatively impact the natural gas demand. This would result in forecasting lower revenues after a rate increase than would actually be the case. On the other hand, the researcher might decide not to reject the null hypothesis when it is false, and falsely conclude that natural gas price does not impact natural gas demand. This error would result in forecasting higher revenues after a rate increase than would actually be the case.

Rejecting the null hypothesis when it is true is called a Type I error for a statistical test. The probability of making a type I error is usually denoted by the Greek symbol  $\alpha$ , and is referred to as the “statistical significance level”. In practice some common values used for

$\alpha$  are 0.10 (a 10 percent chance of a Type I error), 0.05 (a 5 percent chance of a Type I error), 0.025 (a 2.5 percent chance of a Type I error), and 0.01 (a 1 percent chance of a Type I error).

The probability  $\alpha$  will increase or decrease as we increase or decrease the size of the rejection region. Then why not decrease the size of the rejection region and make  $\alpha$  as small as possible? Unfortunately, decreasing  $\alpha$  increases the probability of not rejecting the null hypothesis when it is false and some alternative hypothesis is true. This second type of error is called the type II error for a statistical test and its probably is commonly denoted by the Greek symbol  $\beta$ . More formally, accepting the null hypothesis when it is false is called a type II error for a statistical test. The probability of making a type II error when some specific alternative is true is denoted by  $\beta$ .

Notice that both errors cannot be committed simultaneously. A type I error is possible only if the decision is to reject the null hypothesis; a type II error is possible only if the decision in to not reject the null hypothesis.

When the null hypothesis is rejected in favor of the alternative hypothesis, it is called a statistically significant test. When one fails to reject the null hypothesis, it is referred to as a statistically insignificant test.

As noted on page 29 of Maddala (2001), a statistically significant test means, “sampling variation is an unlikely explanation of the discrepancy between the null hypothesis and the sample values (estimate)”. On the other hand, a statistically insignificant test means, “sampling variation is a likely explanation of the discrepancy between the null hypothesis and the sample value”.

The appropriate test statistic for the null hypotheses tested in this report is the t-statistic, which is reported for each of the coefficients in equations (4a) and (4b). For sample sizes larger than 120 and for an alternative hypothesis that states the price coefficient is less than zero, a t-statistic less than -1.28 is statically significant at the 10 percent level, a t-statistic less than -1.64 is statistically significant at the 5 percent level, a t-statistic less than -1.96 is statically significant at the 2.5 percent level, and a t-statistic less than -2.33 is statistically significant at the 1 percent level.



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Delta Natural Gas Co., Inc.

2006 Test Year Income Statement Compared to 2004-00067

	2003 Test Year per Rate Order	2006 Actual	Favorable (Unfavorable)	Explanation
Operating revenues less gas cost	(27,248,844)	(25,660,624)	(1,588,220)	Decrease in number of customers and lower use per customer due to conservation
O&M expenses	10,232,868	11,502,347	(1,269,479)	Normal increase in costs, 4% per year on average
Depreciation	3,893,537	4,234,739	(341,202)	Increased depreciable plant
Other taxes	1,512,310	1,767,481	(255,171)	Increased payroll and property taxes
Income taxes	2,808,607	1,138,000	1,670,607	Decreased taxable income
Interest expense	4,580,799	4,967,706	(386,907)	Increased borrowings and rates
Net income	<u>(4,220,723)</u>	<u>(2,050,351)</u>	<u>(2,170,372)</u>	





**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

9. Refer to the Jennings Testimony, page 7. Provide the number of large volume customers that have left Delta's system since the last rate case.

RESPONSE:

One customer using in excess of 10,000 Mcf during calendar 2003 has left the system. One additional transportation customer has switched their process load from natural gas to an alternate fuel.

Sponsoring Witness:

John B. Brown



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

10. Refer to the Jennings Testimony, page 8.
- a. Delta states it is concerned that the increase in transportation volumes experienced since its last rate case will not continue. Provide the reason(s) for the 20 percent increase in transportation volumes since the last rate case.
  - b. Delta states it must be able to raise common equity in order to continue to obtain long-term and short-term debt. Explain why the ability to raise common equity is needed in order to obtain long-term and short-term debt.

RESPONSE:

- a. Primarily increased off-system transportation due to increased transportation of gas produced in southeastern Kentucky that Delta delivers to other pipeline systems. This is due to increased natural gas production in the area. The increase in off-system transportation volumes also reflect Delta's efforts to continue to move more gas through its system.
- b. Our experience over the past 30 years indicates that long-term lenders (debentures, bonds) will not lend money at reasonable rates unless the company is not too heavily leveraged with debt. This requires common equity as a component of the balance sheet. Banks will not continue to provide short-term credit lines under reasonable terms and conditions unless the Company is not too heavily leveraged with debt, again requiring common equity as a component of the balance sheet. By striving to keep our equity a significant component of total capital, and by moving toward a 50% ratio of equity-to-debt, we have been able to obtain short and long-term debt on reasonable terms over the years.

Sponsoring Witness:

Glenn R. Jennings



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

11. Refer to the Jennings Testimony, page 11. Mr. Jennings states that Delta's number of employees has dropped from 183 in 1999 to 156 in 2006. However, the response to the Staff's First Request, Item 36, page 2 of 2, indicates there were 183 employees in 2006. Reconcile the two different employee counts for 2006.

**RESPONSE:**

Delta's response to the Staff's First Request, Item 36, page 2 of 2, includes the total full-time and part-time employees that were paid wages in 2006. Mr. Jennings' employee number of 156 only includes the full-time employees as of June 30, 2006, compared to full time employees in 1999.

Sponsoring Witness:

Glenn R. Jennings



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

12. Refer to the Jennings Testimony, pages 12 through 15, regarding his discussion of the CRS mechanism.

a. Explain in detail how the annual reviews of Delta's cost of operations under the CRS will ensure that customers experience more stable and equitable rates and provide customer rate protection.

b. Delta's proposed CRS envisions that the Commission and the AG would be the only participants in the annual filing review. Explain how the process would work if another party sought and was granted intervention in the CRS review.

c. Explain in detail how Delta has determined that the proposed annual reviews will be more cost-effective than the traditional rate case process.

d. Explain in detail what controls are contained in the proposed CRS mechanism that will encourage Delta to contain costs.

**RESPONSE:**

a. Rates will be adjusted annually. Costs will be reviewed annually. Rate adjustments will be in smaller increments due to annual adjustments. The band around an allowed return will keep the utility from over-earning and thus protect customers.

b. This is because those are generally the parties to Delta's rate cases. It is the Commission's discretion to allow intervention. The Commission is the primary review/decision making entity.

c. Delta incurs significant outside costs to file and complete a general rate case. This cost would be less under the CRS, and will save our customers through not having to bear those costs in rates.

d. Delta already is encouraged to contain costs to keep its rates as low as possible to meet competitive pressures and to help in customer retention/addition. The providing of cost information and review by the Commission are the same controls that exist now and they will continue under the CRS. Delta still has the same concerns under CRS to keep rates as low as possible. Reducing rate case expense is one way to help do this.

Sponsoring Witness:

Glenn R. Jennings





**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

13. Refer to the Jennings Testimony, page 13, lines 14 through 16. Delta states that the CRS will “provide only the revenue needed to achieve the rate of return authorized.” Does Mr. Jennings contend that the current rate-making process provides a means in which Delta may achieve a greater rate of return authorized in its last rate case? Explain the response.

**RESPONSE:**

That is possible under the current process, if revenues increased or costs decreased. Delta has not experienced a greater earned rate of return than that authorized, however.

Sponsoring Witness:

Glenn R. Jennings



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

14. Refer to the Jennings Testimony, page 15. Delta states that there should be less staff and outside resources needed by the Commission and the AG to review the annual CRS mechanism proposed in its application. Explain further why the Commission, the AG, or both would need less staff to review Delta's CRS filings.

**RESPONSE:**

Because the CRS filings are not full rate cases, and would not consider rate design, cost of equity, cost of service studies, depreciation studies and the like, this would require less staff time, and certainly less outside consultants by the AG, than is required in general, fully litigated rate cases. Assuming regulated companies need to file annual rate cases, staff needs by the Commission and the AG, as well as outside consultant costs, should be much less under the CRS filing approach.

Sponsoring Witness:

Glenn R. Jennings



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

15. Refer to the Jennings Testimony, page 15, and Exhibit GRJ-1.
- a. Describe the adjustments made to the directors' compensation and the number of directors, as referenced on page 15. Explain the reason(s) for each adjustment.
  - b. Refer to Exhibit GRJ-1, page 6. Revise the chart shown on this page to include the directors' compensation package in effect as of test-year-end.
  - c. Refer to Exhibit GRJ-1, page 13. For each company shown on this schedule, provide the number of retail customers for each company.
  - d. Refer to Exhibit GRJ-1, page 13. For each of the industry peer group companies listed below, explain in detail why the company qualifies as a peer of Delta, given the industry, number of employees, sales, or September 2006 market value.
    - (1) Semco Energy, Inc.
    - (2) Cascade Natural Gas Corp.
    - (3) Chesapeake Utilities Corp.
    - (4) Northwest Natural Gas Co.
    - (5) EnergySouth, Inc.
  - e. Refer to Exhibit GRJ-1, page 14. Based on the analysis shown on page 14, would Delta agree that the only component of total annual compensation that was significantly lower than the peer group was the retainer fee? Explain the response.
  - f. Using the information provided in Exhibit GRJ-1, page 14, describe how Delta compares with the following companies:
    - (1) RGC Resources, Inc.
    - (2) Energy West, Inc.
    - (3) Corning Natural Gas Corp.

**RESPONSE:**

- a. Delta reduced its number of Directors from 10 to 8 effective November 16, 2006. Delta implemented an age policy for its Board and this resulted in 2 members not standing for re-election at the November shareholders' meeting. They were not replaced in order to reduce the size of the Board.

**DELTA NATURAL GAS COMPANY, INC.**  
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**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

- b. Effective December 1, 2006, the monthly compensation for Delta's 7 outside directors was changed. The monthly retainer for those 7 was increased from \$900 to \$1,600 per month. The additional monthly compensation for Committee chairs of \$300 and for committee service of \$400 for the Audit Committee and \$300 for other committees was left unchanged. No other forms of compensation are contemplated. The chairman of the Board, the only inside Director, now receives no compensation for that position.
  
- c. Delta does not have this information as it was not included in the report by Mercer Human Resource Consulting. Delta hired these outside consultants, as an independent third party, in compliance with the Commission's directive in its Order in Case 2004-00067. Mercer determined how they would perform their independent study and selected the peer group, based upon their experience and judgment. We requested them to review our Board compensation and make recommendations, and then our Board used their report to consider and revise Delta's Board compensation in November, 2006.
  
- d. See response to 15(c).
  
- e. No, for several reasons.
  - (1) Most companies pay meeting fees for Board meetings and Committee meetings. Delta does not.
  - (2) Delta combined its Corporate Governance, Nominating and Compensation Committees. Other companies mostly have separate ones leading to additional compensation for them.
  - (3) Some others provide stock and stock options as equity compensation. Delta does not.
  - (4) The average total compensation in the peer group was \$43,842, compared to Delta's \$22,500.
  - (5) After Delta's changes, Delta's Board compensation is projected to be still much less than the peer group. Based upon Delta's Board as now constituted, Delta's annual Board compensation is now \$182,400, an average of \$22,800.
  
- f. See response to 15(c).

Sponsoring Witness:

Glenn R. Jennings



**DELTA NATURAL GAS COMPANY, INC.**  
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16. Refer to the Application, the Direct Testimony of John B. Brown (“Brown Testimony”), page 6. Mr. Brown states, “While the results of a test year will never perfectly predict expenses in subsequent years, we believe that our 2006 test year, as adjusted and taken as a whole, is a conservative representation of our expenses in subsequent years.”
- a. Would Delta agree that in rate-making, the proposed adjustments to a test year should attempt to establish a reasonable, on-going level of revenues and expenses for the utility? Explain the response.
  - b. Explain in detail how “a conservative representation” of expenses is consistent with the establishment of a reasonable, on-going level of expenses.

RESPONSE:

- a. Delta does agree that in rate-making, proposed adjustments to a test year are to establish a test period that is the measure of a representative level of the costs of operations and investment during the period for which rates are being set.
- b. Delta limited its test year operating expense adjustments to known and measurable changes, while foregoing any normalization adjustments, based on historical experience, in order to simplify its filing. Delta believes, as set forth in Brown Testimony, that if it did make normalization adjustments, the four most significant would be to increase test year operating expenses for property taxes, medical coverage, uncollectible accounts and legal costs. Because Delta believes that, based on historical experience, the net effect of making normalization adjustments to test year operating expenses would be to increase such expenses, it has characterized its adjusted test year as a conservative representation of the cost of operations during the period for which rates are being set. In addition, Brown Testimony highlights that if interested parties do propose normalization adjustments to test year operating expenses, the four accounts he has identified should be included.

Sponsoring Witness:

John B. Brown





**DELTA NATURAL GAS COMPANY, INC.**  
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17. Refer to the Brown Testimony, page 7.

a. Has Delta examined its medical coverage expense, its uncollectible accounts expense, and its legal expenses to try and determine why the test-year amounts were lower in 2006 than in previous years?

(1) If yes, provide the reason(s) identified for the expense reductions.

(2) If no, explain in detail why Delta has not undertaken such an analysis.

b. Provide the last medical coverage premium paid during the test year and calculate a normalized level of expense based on that last premium.

c. Refer to the response to the Staff's First Request, Item 32. Given the historic data concerning the current provision for uncollectible accounts and the percentage of the current provision to total revenues, would Delta agree that an adjustment could have been proposed reflecting an average of its recent historic experience? Explain the response, and if Delta agrees describe how it would determine a proposed adjustment.

**RESPONSE:**

(a) (1) \$65,000 of the reduction is the one time effect of lowering the "incurred but not reported" reserve. This reserve was lowered based on a lag study performed in 2006. Delta's Health Plan Committee annually reviews data gathered by outside sources and takes appropriate actions to cut costs. In 2006, the Plan implemented a required pre-certification and utilization review in addition to Case Management already in place. All inpatient hospital admissions, physical or occupational services require pre-certification. Case Management applies if the condition is, or is expected to become catastrophic or chronic, or when the cost of treatment is expected to be significant. In addition, the out of pocket medical maximum per calendar year was increased, as well as, employee contributions. Delta's Health Benefits Plan is a self-insured plan. Expenses are based on claims incurred therefore; expenses will vary from one year to the next. For example, expenses for the first five months of 2007 have run \$227,291 above the first five months of the test year.

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Uncollectible account expense was lower during the test year primarily due to a lowering of the allowance for doubtful accounts. The allowance for doubtful accounts was \$500,142 at 12/31/05 and decreased to \$400,025 at 12/31/06. The balance in the reserve for doubtful accounts is based on management's estimate of the level of uncollectible accounts. During 2006, we implemented a new computer program that has the capability to better predict future write-offs based on past trends. The new program showed that our reserve was higher than necessary so we lowered the reserve accordingly, thus, lowering test year expense. We believe that this is a one-time reduction in expense.

Legal expenses were lower during the test year due to the fact that we had very little litigation activity. We had spent a significant amount of time and money during 2005 preparing to defend against a suit by a retiree. This suit was dismissed in early 2006 and we have been involved in no more lawsuits since. In addition, the test year includes \$18,017 of credits that represent corrections of amounts booked in the previous calendar year (2005).

- (a) (2) N/A
- (b) Delta's Health Plan is a self-funded plan with a stop-loss insurance policy that covers expenses over \$75,000 annually per covered individual. The cost of this policy during the test year was \$193,309. The quote for the same coverage in 2007 is \$209,225.
- (c) We agree that an adjustment could have been proposed reflecting an average of our recent historical experience, but to propose such an adjustment is not in keeping with the spirit of the case we filed. We attempt to adjust accounts only when the pro-forma amount is both known and measurable.

If the PSC chooses to adjust certain accounts based on historical experience, we agree that any of the three accounts discussed in this question would be appropriate candidates. Specifically, regarding uncollectible accounts, we would propose computing net write-offs as a percentage of operating revenue. Using net-write-offs rather than the "current year provision" takes out the impact of adjusting the reserve in any given year, as was discussed in (a)(1) of this response. Using the four years in the Staff's First Request, Item 32, the average percent of net-write-offs to operating revenue is .865% applied to Pro Forma operating revenue of \$66,612,465 yields \$576,198, a \$92,722 increase in expense over test year levels.

Sponsoring Witness:

John B. Brown



**DELTA NATURAL GAS COMPANY, INC.**  
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18. Refer to the Brown Testimony, pages 7 and 8. On page 7, starting at line 18, Mr. Brown states, "By keeping our pro forma adjustments to a minimum, we encourage the Commission to utilize the historical test year." Explain in detail how limiting its proposed adjustments results in "encouraging" the utilization of a historic test year.

**RESPONSE:**

As discussed in the response to 16, in order to simplify its filing, Delta did not make normalization adjustments, based on historical experience, to test year operating expenses. Delta is "encouraging" the utilization of its historic test year, with known and measurable changes, in order to avoid being subjected to normalization adjustments which have been selectively limited to only those decreasing test-year operating expenses. Delta believes that if normalization adjustments are made to its historic test year operating expenses, such adjustment should be comprehensive.

Sponsoring Witness:

John B. Brown



**DELTA NATURAL GAS COMPANY, INC.**  
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19. In the November 10, 2004 Order in Case No. 2004-00067, the Commission addressed adjustments related to Delta's 401(k) plan expenses, pension expense, and Sarbanes-Oxley compliance expenses. In the current case, no adjustments have been proposed for these items.
- a. Concerning Delta's 401(k) plan expenses:
    - (1) Provide the test-year level of expense.
    - (2) Describe any changes to the 401(k) plan that were initiated during the test year or in the months subsequent to the test year. Include a discussion of the affect the changes would have on the expense level.
    - (3) Using the most current plan invoices, determine a normalized 401(k) plan expense for Delta. Include all workpapers, calculations, and assumptions.
  - b. Concerning Delta's pension expense:
    - (1) Provide the test-year level of expense.
    - (2) Provide copies of the most current actuary analysis of Delta's net periodic pension expense.
    - (3) Using the most current actuary analysis of the net periodic pension expense, determine a normalized pension expense. Include all workpapers, calculations, and assumptions.
  - c. Concerning Delta's Sarbanes-Oxley compliance expenses:
    - (1) Provide the test-year level of expense, showing in detail the various components of the compliance expense.
    - (2) Describe any changes to Delta's Sarbanes-Oxley compliance expenses that occurred during the test year or in the months subsequent to the test year. Include a discussion of the affect the changes would have on the expense level.

RESPONSE:

- a.
  - (1) The test year expenses for the 401K employee savings plan consists of matching contributions of \$205,217 and administrative expenses of \$35,622 for a total of \$240,839.
  - (2) The 401K Employee Savings Plan was amended to comply with Regulations in 2005. There were no changes in the test year.
  - (3) Since there have been no changes in the plan, the plan year expense should be representative. One could argue that the test year should be increased by the expected 1.2% increase in salaries, as provided in the test year. With test year 401K expenses being \$240,839 the adjustment would be \$2,890, yielding a total 401K expense of \$243,729.

**DELTA NATURAL GAS COMPANY, INC.**  
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**SECOND PSC DATA REQUEST**  
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b.

- (1) Test year pension expense is \$700,262.
- (2) See report, Item 19b(2), dated 8/11/06, attached.
- (3) The attached report, Item 19b(3), while the latest currently available, only projects expense through 3/31/07. Given the fluctuating nature of pension expense, it would be more accurate to wait until the 3/31/08 expense projection becomes available before computing the normalized pension expense. If we are going to base an adjustment on historical experience, we would average the 3/31/07 expected expense of \$567,300 as the report attached in (b) above with the three preceding years to compute normal pension expense to be \$639,919, a \$60,343 reduction in test year expense.

c.

- (1) We incurred no external costs during the test year relating to Sarbanes-Oxley compliance except for the fees paid to Deloitte & Touche to issue the required opinions resulting from the integrated audit. Since the audit is now integrated, it is not possible to segregate the cost of the Sarbanes Oxley opinions from the financial statement audit opinion.
- (2) There have been no changes to the Sarbanes-Oxley compliance expenses occurring during the test year. Some of the regulations have recently been relaxed by the PCAOB, but Deloitte & Touche has assured us that the recent scope reduction will only partially curb future increases, not result in a decrease in fees.

Sponsoring Witness:

John B. Brown



HAND BENEFITS &amp; TRUST, INC.



August 11, 2006

Mr. Glenn Jennings  
Delta Natural Gas Company, Inc.  
3617 Lexington Road  
Winchester, KY 40391

RE: Delta Natural Gas Company, Inc. Defined Benefit Retirement Plan--Financial Accounting Disclosure under SFAS Nos. 87 and 132 as of March 31, 2006

Dear Mr. Jennings:

We have enclosed the Accounting Requirements Actuarial Valuation for the Delta Natural Gas Company, Inc. Defined Benefit Retirement Plan as of March 31, 2006. The purpose of this report is to provide the plan sponsor and its auditors with the disclosure information and pension cost information required under Statements of Financial Accounting Standards (SFAS) Nos. 87 and 132 for the sponsor's March 31, 2006 financial statement. The results of this valuation are appropriate for these purposes only.

**Recognition of Plan Expense, Liabilities, and Assets  
on Employer's Financial Statements**

Net periodic benefit cost is an expense/(income) entry on the income statement and is determined separately from the plan sponsor's cash contribution requirement.

A liability (accrued pension cost) is recognized on the balance sheet if the sum of all historical net periodic benefit costs exceeds cumulative cash contributions by the sponsor. An asset (prepaid pension cost) is recognized on the balance sheet if cumulative net periodic benefit costs are less than the cumulative cash contributions by the sponsor.

The accumulated benefit obligation is the discounted present value of benefits accrued by the financial statement measurement date. If the accumulated benefit obligation exceeds the fair value of plan assets, the plan sponsor must recognize in the statement of financial position a liability (including accrued pension cost) that is at least equal to the unfunded accumulated benefit obligation.

Recognition of an additional minimum liability is required if an unfunded accumulated benefit obligation exists and an asset has been recognized as prepaid pension cost. If an additional liability required to be recognized exceeds any intangible asset (unrecognized transition obligation plus prior service cost), the excess is reported as a separate component of equity (i.e., as a reduction to equity). Changes in the amount of additional liability recognized from year to year that are not offset by an intangible asset are recorded in "Other Comprehensive Income".

## Executive Summary

The Net Periodic Benefit Cost of \$717,106 for the fiscal year ending March 31, 2006 is developed in the attached exhibits. The Net Periodic Benefit Cost of \$567,300 for the fiscal year ending March 31, 2007 is also developed within.

As of March 31, 2006, the Accumulated Benefit Obligation of \$11,847,991 is smaller than the Fair Value of Plan Assets of \$13,067,828. Therefore, there is no Unfunded Accumulated Benefit Obligation, Minimum Liability, nor Additional Liability as of March 31, 2006.

SFAS Nos. 87 and 132 require that the year-end liability amount be calculated using an appropriate discount rate based on the interest rate environment on the measurement date, March 31, 2006. The discount rate is a defined assumption under the accounting rules and is subject to limited discretion.

The plan sponsor makes the ultimate decision on the selection of a discount rate. We have used a rate of 5.80%, selected by Delta Natural Gas Company, Inc., as the pre-retirement and post-retirement discount rate for March 31, 2006 year-end disclosure calculations. This rate will also be the discount rate used for development of the Net Periodic Benefit Cost for the fiscal year beginning April 1, 2006. A discount rate of 5.80% was used for the March 31, 2005 disclosure.

### Changes to Actuarial Assumptions

This valuation reflects the following changes to the assumptions:

The mortality assumption was changed from the 1983 Group Annuity Mortality Table to the 1994 Group Annuity Reserving Mortality Table (94 GAR), a unisex table prescribed under IRS Revenue Ruling 2001-62.

The assumed form of payment for the pre-November 1, 2002 benefit was changed from annuity to lump, with an assumed lump sum election rate of 100%. The lump sums for valuation purposes are calculated using a 5.75% assumed interest rate and the 94 GAR table. (The prior valuation applied this assumption implicitly, by using a 5.75% post-decrement discount rate.)

If you have any questions concerning this information, please call or write.

Respectfully submitted,

**HAND AND ASSOCIATES, INC.**



Frederick Nelson, ASA, EA  
Senior Staff Actuary

FN/mat  
Enclosures

**Delta Natural Gas Company, Inc. Defined Benefit Retirement Plan**

**Statements of Financial Accounting Standards Nos. 87 and 132  
Actuarial Valuation  
as of  
March 31, 2006**

**For March 31, 2006 Disclosure**

**Prepared by:  
Hand and Associates, Inc.**

**Delta Natural Gas Company, Inc. Defined Benefit Retirement Plan**

Financial Accounting Disclosure under SFAS Nos. 87 and 132

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- A. Disclosure for Fiscal Year Ending March 31, 2006
- B. Net Periodic Benefit Cost For Fiscal Year Ending March 31, 2007
- C. Obligations and Funded Status
- D. Minimum Liability, Additional Liability, Intangible Asset, and Accumulated Other Comprehensive Income
- E. Reconciliation of Funded Status
- F. Other Information
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## Delta Natural Gas Company, Inc. Defined Benefit Retirement Plan

Certification of SFAS Nos. 87 and 132 Actuarial Valuation  
(As of March 31, 2006)

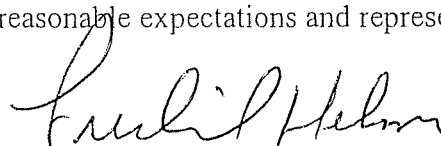
At the request of Delta Natural Gas Company, Inc. we have prepared an actuarial valuation of the Plan as of March 31, 2006 in accordance with Statement of Financial Accounting Standards (SFAS) No. 87 (Employers' Accounting for Pensions) and No. 132 (Employers' Disclosures about Pensions and Other Postretirement Benefits). The purpose of this report is to provide the information necessary to determine financial statement entries consistent with SFAS 87 and 132 for the fiscal year ending March 31, 2006 and the net periodic benefit cost entry for the fiscal year beginning April 1, 2006.

Actuarial calculations under SFAS Nos. 87 and 132 are intended to fulfill a plan sponsor's accounting requirements. The results reported within this report have been developed on a basis consistent with our understanding of SFAS Nos. 87 and 132. Calculations intended for purposes other than meeting financial accounting requirements may be significantly different from the results reported within this report. Accordingly, the results in this report should not be used for determinations needed for other purposes, such as judging benefit security at plan termination or assessing the adequacy of funding for an ongoing plan.

We have based our valuation on employee data as of March 31, 2006 as provided by Delta Natural Gas Company, Inc. and asset information as of March 31, 2006 as provided by Hand Benefits & Trust Company. To the best of my knowledge, no material biases exist with respect to any imperfections in the data provided by these sources. To the extent any imperfections exist in the historical compensation database, we have addressed the imperfections by applying the salary increase assumptions specified in the "Actuarial Assumptions and Methods" section of this report. We have not audited the data provided, but have reviewed it for reasonableness and consistency with previously-provided information. We have used the actuarial funding methods and assumptions described in the "Actuarial Assumptions and Methods". This actuarial valuation has been prepared on the basis of the plan benefits described in the "Major Plan Provisions" section of this report.

All current employees eligible to participate in the Plan as of the valuation date and all other individuals who have a remaining vested benefit under the Plan have been included in the valuation. Further, all Plan benefits have been considered in the development of plan costs.

In my opinion, each assumption used for this report that is subject to the discretion of the actuary is reasonably related to the experience of the Plan and to reasonable expectations and represents my best estimate of anticipated experience.



Frederick Nelson  
Associate of the Society of Actuaries  
Enrolled Actuary Number 05-4692

DELTA NATURAL COMPANY, INC.  
DEFINED BENEFIT RETIREMENT PLAN

Information Disclosed Under Statements of Financial Accounting Standards Nos. 87 and 132  
For Fiscal Year Ending March 31, 2006

<u>FUNDED STATUS</u>	Actual 3/31/2005	For Fiscal 2005 - 2006	Projected to 3/31/2006	Actual 3/31/2006
Projected Benefit Obligation	\$ (12,086,832)		\$ (12,991,402)	\$ (12,696,303)
Plan Assets at Fair Value	11,301,413		13,160,038	13,067,828
Funded Status	\$ (785,419)		\$ 168,636	\$ 371,525
Unrecognized Net Obligation or (Asset) Existing at Transition	\$ -		\$ -	\$ -
Unrecognized Prior Service Cost	(1,112,124)		(1,025,945)	(1,025,945)
Unrecognized Net (Gain) or Loss	5,068,790		4,811,450	4,608,561
(Accrued)/Prepaid Pension Cost	\$ 3,171,247		\$ 3,954,141	\$ 3,954,141

ASSUMPTIONS

Discount Rate	5.80%
Expected Long Term Rate of Return	8.00%
Rate of Increase in Compensation	4.00%
Average Remaining Future Years of Service	15.00
Measurement Date	3/31/2005

5.80%	3/31/2006
8.00%	
4.00%	
14.16	
3/31/2006	

NET PERIODIC BENEFIT COST

Service Cost	\$ 779,702	(Accrued)/Prepaid Benefit Cost at March 31, 2005	\$ 3,171,247
Interest Cost	697,556		
Expected (Return) on Assets	(931,313)	Net Periodic Benefit (Cost)/Income	(717,106)
Amortization of: Unrecognized Net Obligation or (Asset) Existing at Transition	-	Actual Contributions	1,500,000
Unrecognized Prior Service Cost	(86,179)	(Accrued)/Prepaid Benefit Cost at March 31, 2006	\$ 3,954,141
Unrecognized Net (Gain) or Loss	257,340		
Net Periodic Benefit Cost (Income)	\$ 717,106		

Accumulated Benefit Obligation as of March 31, 2006: \$11,847,991

DELTA NATURAL GAS COMPANY, INC.  
DEFINED BENEFIT RETIREMENT PLAN

Net Periodic Benefit Cost -- Statement of Financial Accounting Standards No. 87  
for the Fiscal Year Ending March 31, 2007

<u>FUNDED STATUS</u>	Actual 3/31/2006	<u>NET PERIODIC BENEFIT COST</u>
Projected Benefit Obligation	\$ (12,696,303)	\$ 715,766
Plan Assets at Fair Value	<u>13,067,828</u>	699,807
Funded Status	\$ 371,525	(995,235)
Unrecognized Net Obligation or (Asset) Existing at Transition	\$ -	-
Unrecognized Prior Service Cost	(1,025,945)	(86,214)
Unrecognized Net (Gain) or Loss	<u>4,608,561</u>	<u>233,176</u>
(Accrued)/Prepaid Pension Cost	<u>\$ 3,954,141</u>	<u>\$ 567,300</u>

ASSUMPTIONS

Discount Rate	5.80%
Expected Long Term Rate of Return	8.00%
Rate of Increase in Compensation	4.00%
Average Remaining Future Years of Service	14.16
Measurement Date	3/31/2006

RECONCILIATION

(Accrued)/Prepaid Benefit Cost at March 31, 2006	\$ 3,954,141
Net Periodic Benefit (Cost)/Income	(567,300)
Assumed Contributions Paid	<u>1,500,000</u>
Projected (Accrued)/Prepaid Benefit Cost at March 31, 2007	<u>\$ 4,886,841</u>

**DELTA NATURAL GAS COMPANY, INC.  
DEFINED BENEFIT RETIREMENT PLAN**

**Obligations and Funded Status  
Statements of Financial Accounting Standards Nos. 87 and 132**

	<u>Fiscal Year Ending March 31, 2006</u>	<u>Fiscal Year Ending March 31, 2005</u>
<b>Change in Benefit Obligation</b>		
Benefit Obligation at beginning of year	\$ (12,086,832)	\$ (10,267,056)
Service Cost	(779,702)	(714,801)
Interest Cost	(697,556)	(612,370)
Plan Participants' Contributions	-	-
Amendments	-	-
Actuarial Gain / (Loss)	295,099	(1,017,431)
Acquisition	-	-
Benefits Paid	572,688	524,826
Benefit Obligation at end of year	<u>\$ (12,696,303)</u>	<u>\$ (12,086,832)</u>
<b>Change in Plan Assets</b>		
Fair value of assets at beginning of year	\$ 11,301,413	\$ 10,450,066
Actual return on plan assets	839,103	343,517
Acquisition	-	-
Employer Contribution	1,500,000	1,032,656
Plan Participants' Contributions	-	-
Benefits Paid	(572,688)	(524,826)
Fair value of assets at end of year	<u>\$ 13,067,828</u>	<u>\$ 11,301,413</u>
<b>Recognized/Unrecognized Amounts</b>		
Funded Status	\$ 371,525	\$ (785,419)
Unrecognized Net Actuarial Loss (Gain)	4,608,561	5,068,790
Unrecognized Transition (Asset)/Obligation	-	-
Unrecognized Prior Service Cost	(1,025,945)	(1,112,124)
Net Amount Recognized	<u>\$ 3,954,141</u>	<u>\$ 3,171,247</u>
<b>Components of Net Periodic Benefit Cost</b>		
Service Cost	\$ 779,702	\$ 714,801
Interest Cost	697,556	612,370
Expected (return) on assets	(931,313)	(863,061)
Amortization of prior service cost	(86,179)	(86,179)
Amortization of transition obligation (asset)	-	-
Amortization of unrecognized loss (gain)	257,340	177,629
Net periodic benefit cost	<u>\$ 717,106</u>	<u>\$ 555,560</u>
Projected benefit obligation, accumulated benefit obligation, and fair value of plan assets		
	\$12,696,303, \$11,847,991, and \$13,067,828 as of March 31, 2006	
	\$12,086,832, \$10,936,279, and \$11,301,413 as of March 31, 2005	
<b>Assumptions</b>		
Discount Rate	5.80%	5.80%
Expected return on assets	8.00%	8.00%
Rate of compensation increase	4.00%	4.00%



**DELTA NATURAL GAS COMPANY, INC.  
DEFINED BENEFIT RETIREMENT PLAN**

**Determination of  
Minimum Liability, Additional Liability, Intangible Asset  
and Accumulated Other Comprehensive Income**

	Fiscal Year Ending March 31, 2006	Fiscal Year Ending March 31, 2005
<b>Minimum Liability; Additional Liability</b>		
1 Accumulated Benefit Obligation	\$ 11,847,991	\$ 10,936,279
2 Fair Value of Plan Assets	<u>13,067,828</u>	<u>11,301,413</u>
3 Minimum Liability (Unfunded ABO) [(1) - (2), not less than 0]	\$ -	\$ -
4 (Accrued)/Prepaid Pension Expense	<u>3,954,141</u>	<u>3,171,247</u>
5 Additional Liability [(3) + (4) not less than \$0, and only if (3) > 0]	\$ -	\$ -
<b>Intangible Asset</b>		
6 Unrecognized Transition Obligation (Asset)	\$ -	\$ -
7 Unrecognized Prior Service Cost	(1,025,945)	(1,112,124)
8 Maximum Intangible Asset [(6) + (7), not less than \$0]	-	-
9 Actual Intangible Asset - lesser of (5) or (8)	-	-
10 Accumulated Other Comprehensive Income [(5) - (9)]	-	-

**DELTA NATURAL GAS COMPANY, INC.  
DEFINED BENEFIT RETIREMENT PLAN**

**Reconciliation of Funded Status  
Statements of Financial Accounting Standards Nos. 87 and 132  
for Fiscal Years Ending March 31**

	2006	2005
Accumulated Benefit Obligation (ABO)	\$ (11,847,991)	\$ (10,936,279)
Future Salary Increases	<u>(848,312)</u>	<u>(1,150,553)</u>
Projected Benefit Obligation	\$ (12,696,303)	\$ (12,086,832)
Plan Assets	<u>13,067,828</u>	<u>11,301,413</u>
Funded Status	\$ 371,525	\$ (785,419)
Unrecognized Net (Gain)/Loss	4,608,561	5,068,790
Unrecognized Transition (Asset)/Obligation	-	-
Unrecognized Prior Service Cost	<u>(1,025,945)</u>	<u>(1,112,124)</u>
(Accrued)/Prepaid Pension Cost	<u>\$ 3,954,141</u>	<u>\$ 3,171,247</u>

**DELTA NATURAL GAS COMPANY, INC.  
DEFINED BENEFIT RETIREMENT PLAN**

**Other Information**

<u>Asset Category</u>	Plan Assets	
	<u>2006</u>	<u>2005</u>
Equity securities	54 %	52 %
Debt securities	34	39
Real estate	0	0
Other	12	9
Total	<u>100 %</u>	<u>100 %</u>

**Contributions**

Delta Natural Gas Company, Inc. expects to contribute \$1,500,000 to its Retirement Plan for the 2006-2007 Plan Year.

**Estimated Future Benefit Payments**

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	<u>Pension Benefits</u>
2006	\$ 1,279,000
2007	468,000
2008	896,000
2009	506,000
2010	910,000
Years 2011-2015	8,411,000

## Delta Natural Gas Company, Inc. Defined Benefit Retirement Plan

### Major Plan Provisions

Eligibility:	All employees who are employed on a basis to work 1,000 hours or more per year, and who, as of April 1 or October 1, have been employed for 12 months or longer.
Considered Compensation:	Total basic monthly salary earned in the twelve month period ending January 31 preceding the valuation date including deferrals under IRC § 401(k) and 125.
Normal Retirement Date:	First of the month coincident with or following the attainment of Age 65.
Normal Retirement Benefit:	<p>The monthly retirement benefit, payable at normal retirement date for 120 months certain and life, is equal to 1.6% of high-consecutive-five-year average monthly salary per year of service for service after November 1, 2002.</p> <p>Prior to November 1, 2002, the monthly retirement benefit was equal to 1.8% of high-consecutive-five-year average monthly salary per year of service at normal retirement date, plus .55% of high-consecutive-five-year average monthly salary in excess of Social Security Covered Compensation Table II for each year of service not to exceed 35 years.</p>
Early Retirement Benefit:	A participant who has attained age 55 and has completed 15 or more years of service may retire and receive an immediate monthly retirement benefit equal to his accrued benefit reduced 5% (.4167% per month) for each year by which early retirement precedes normal retirement.
Pre-Retirement Death Benefit:	The death benefit is the greater of the present value of the vested accrued benefit or \$1,000 for each \$10 of projected monthly retirement benefit. However, the death benefit for a participant employed beyond his normal retirement date is the present value of the accrued benefit. (Accrued Benefits provided under the Prior Plan Metropolitan Group Annuity Contract are <u>not</u> considered).

## Delta Natural Gas Company, Inc. Defined Benefit Retirement Plan

### Major Plan Provisions

(continued)

Disability Benefit: In the event a participant becomes totally and permanently disabled, as determined by the Plan Committee, he is entitled to receive the benefit provided by the present value of the accrued pension.

Vesting: Participants become vested in their accrued benefits in accordance with the following schedule:

<u>Years of Credited Service</u>	<u>Vested Percentage</u>
0-3	0%
3	20%
4	40%
5	60%
6	80%
7 & thereafter	100%

Single Sum Distribution Availability: Upon termination of employment, single sum distributions are available up to \$5,000. If the event of death, disability, normal retirement age or early retirement age, single sums are available regardless of the amount, for benefits accrued prior to December 1, 2002.

The \$5,000 restriction will apply to all accruals after December 1, 2002.

Assumptions for Determining Actuarially Equivalent Benefits:

Benefits Payable in the Form of a Monthly Annuity:

Mortality: 1994 Group Annuity Reserving Mortality Table  
Interest: 8% per year, compounded annually

**Delta Natural Gas Company, Inc. Defined Benefit Retirement Plan**

Major Plan Provisions  
(continued)

Benefits Payable in the Form of a  
Single Sum Distribution:

Mortality:	1994 Group Annuity Reserving Mortality Table
Interest:	30-year Treasury security rate for the month of March preceding the plan year in which distribution takes place

Changes Since Prior Valuation:	None
--------------------------------	------

**Delta Natural Gas Company, Inc. Defined Benefit Retirement Plan**

Actuarial Assumptions and Methods

Funding Method:	Projected Unit Credit	
Market-Related Value of Assets:	Market Value	
Actuarial Assumptions:		
Discount Rate:		
For March 31, 2005 Disclosure	Pre-retirement: 5.80%; Post-retirement: 5.75%	
For March 31, 2006 Disclosure	5.80% per year	
Expected Long-term Rate of Return:	8.00% per year, compounded annually	
Mortality:	1994 Group Annuity Reserving Mortality Table (94 GAR) (unisex table prescribed by IRS Revenue Ruling 2001-62)	
Turnover:	In accordance with the following table:	
	<u>Past Service</u>	<u>Scale</u>
	0 - 5 Years	T-5
	5+ Years	T-2
	The termination scales are the Crocker, Sarason and Straight turnover rates.	
Disability:	None assumed	
Salary Increase:	4% per year	
Lump Sums:	Interest rate: 5.75%	
	Mortality table: 94 GAR	
	Incidence: 100% of eligible participants	
Increase in benefit and compensation limits:	2.50% per year	
Retirement Rates:	<u>Ages</u>	<u>Rate</u>
	55-61	2.0%
	62	5.0%
	62-64	2.0%
	65	100.0%

**Delta Natural Gas Company, Inc. Defined Benefit Retirement Plan**

Actuarial Assumptions and Methods

(continued)

Benefits or Participants Excluded From the Valuation:	None
Measurement Date:	March 31
Census Date:	March 31 of the reporting year, with adjustments to the measurement date as appropriate.
Amortization Methods	
Prior Service Cost:	Straight-line over average remaining service period of employees affected.
Gains and Losses:	“10% corridor” approach. Otherwise, same method as for Prior Service Cost.
Changes Since Prior Valuation:	<p>The mortality assumption was changed from the 1983 Group Annuity Mortality Table to the 1994 Group Annuity Reserving Mortality Table (94 GAR), a unisex table prescribed under IRS Revenue Ruling 2001-62.</p> <p>The assumed form of payment for the pre-November 1, 2002 benefit was changed from annuity to lump sum, with an assumed lump sum election (incidence) rate of 100%. The lump sums for valuation purposes are calculated using an assumed interest rate of 5.75% and the 94 GAR table.</p>





**DELTA NATURAL GAS COMPANY, INC.  
CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST  
DATED 6/07/07**

20. Refer to the Brown Testimony, Exhibit JB-1.
- a. The listing of expenses on this exhibit includes references to six footnotes. However, no footnotes for the numbered references were provided. Provide the missing information.
  - b. Delta estimates that the supplies/postage cost associated with the reconnection/disconnection, collection and bad check charge is \$3.00 per hour. Provide a detailed explanation of what is included in that list and how Delta determined that cost.
  - c. Provide a detailed explanation of what is included in the transportation cost under miscellaneous expense for the reconnect/disconnect, collection and bad check charges.

**RESPONSE:**

- a. See attached revised Exhibit JB-1.
- b. The \$3.00 cost associated with supplies/postage is not based on hourly rate, but a set charge for reconnect/disconnection, collection and bad check charge. This cost remains the same as requested in the previous rate case. This estimate includes any office supplies, such as paper, pens/pencils, printer supplies and postage.
- c. See attached schedule.

Sponsoring Witness:

John B. Brown

DELTA NATURAL GAS CO., INC.  
 Special Charge Cost Study  
 Test Year Ended December 31, 2006

	RECONNECT-DISCONNECT		COLLECTION		BAD CHECK	
	HOURS	AMOUNT/HR	HOURS	AMOUNT/HR	HOURS	AMOUNT/HR
I.						
Field Expense						
Labor (1) (2)	1.5	\$ 37.71	0.5	\$ 12.57	0	\$ -
II.						
Clerical & Office Expense (3)						
Supplies/ postage		3.00		3.00		3.00
Other charges - bank fees, etc.						10.00
Labor (4)	1.5	\$ 28.52	0.5	\$ 9.51	0.25	\$ 4.75
III.						
Miscellaneous Expense (5)						
Transportation (6)	1.5	\$ 6.55	0.5	\$ 2.18		\$ -
TOTAL EXPENSE		\$ 75.78		\$ 27.26		\$ 17.75

- (1) Labor hours are an average estimated by operations personnel
- (2) Labor rate based on operations labor total annual salary, taxes and benefits as of 12/31/06
- (3) Depreciation for office equipment not included
- (4) Labor rate based on clerical labor total annual salary, taxes and benefits as of 12/31/06
- (5) Depreciation for tools not included
- (6) Average cost of transportation per hour worked

DELTA NATURAL GAS COMPANY  
RATE CASE 2007-00089  
Special Charge Cost Study  
Test Year Ended December 31, 2006

Exhibit JB1  
PSC 2 - Item 20. C.

**Calculation of Transportation Cost for reconnect/disconnect collection and bad check charges:**

<b>LINE NO.</b>	<b>DESCRIPTION</b>	<b>AMOUNT</b>	<b>REFERENCE</b>
1	Total Transportation Cost Year end 12/31/06	\$ 980,212.00	(a)
2	Less Administration Transportation Cost	\$ 94,100.00	(b)
3	Net Cost Field Transportation	\$ 886,112.00	(c)
4	Total Number Field Hours from Payroll	203,070	(d)
5	Avg Cost Transportation per Hour	\$ 4.36	(e)
6	Calculation formula Avg Cost Transportation per Hour : $c / d = e$		



DELTA NATURAL GAS COMPANY, INC.  
CASE NO. 2007-00089

SECOND PSC DATA REQUEST  
DATED 6/07/07

21. Refer to the Application, the Direct Testimony of Matthew D. Wesolosky (“Wesolosky Testimony”), page 4. Provide copies of *The Minority Report of The Advocates for Energy Efficiency and the Environment on the Energy Efficiency Task Force Convened by the Kentucky Department of Public Protection* released on February 26, 2007.

RESPONSE:

Please refer to the attached Minority Report from the Task Force. Additionally, please note that although the report represents a minority opinion of the Task Force, the majority was not opposed to the findings related to DSM programs. The majority only determined that DSM programs were outside of the scope Task Force’s mandate. Also included is the report release by the majority of the Task Force which notes, “we encourage both the PSC and the Governor’s Office on Energy Policy to continue their dialog with Kentucky’s regulated utilities to identify the most effect strategies for advancing energy efficiency and conservation programs.”

Sponsoring Witness:

Matthew D. Wesolosky

1 Department of Public Protection  
2 Report of the Task Force on Energy  
3 Efficient Housing and Construction  
4

5 The Task Force on Energy Efficient Housing and Construction (Task Force) was initiated  
6 in June 2006 to draw on the expertise of agencies within the Department of Public  
7 Protection to find opportunities for greater energy efficiency in Kentucky's housing and  
8 construction industries. The primary topics the Task Force examined were increasing  
9 energy efficiency of homes and other structures and minimizing energy use and waste  
10 during construction.

11 The Task Force was organized under the auspices of the Commissioner of Public  
12 Protection, with the Office of Housing, Buildings and Construction and the Kentucky  
13 Public Service Commission as the lead participating agencies. The Kentucky Office of  
14 Energy Policy also was a key participant.

15 Participants from outside state government included representatives of utility companies,  
16 the housing and construction industries, the architectural profession, institutions of higher  
17 education and the environmental community. A complete list of participants is appended.  
18 Throughout its deliberations, the Task Force was guided by the following  
19 recommendations included in Governor Fletcher's Comprehensive Energy Policy, which  
20 was issued in February 2005:

- 21 • The Commonwealth of Kentucky should require interagency cooperation to  
22 promote energy efficiency initiatives.
- 23 • The Commonwealth of Kentucky should encourage the continued development of  
24 public private partnerships dedicated to promoting energy efficiency through  
25 education and outreach.
- 26 • The Commonwealth of Kentucky should work with industries, businesses,  
27 schools, universities and communities to promote and give preference to energy  
28 efficient products and practices.

- 1 • The Commonwealth of Kentucky should examine its building codes and  
2 specifications to determine if enhanced energy efficiency gains are possible  
3 through progressive policy.

4 The Task Force met four times during the summer and fall of 2006 to discuss and  
5 develop its findings and recommendations. Shortly after the final meeting, Governor  
6 Fletcher issued an Executive Order transferring the Office of Energy Policy from the  
7 Commerce Cabinet to the Office of the Governor. The Task Force commends the  
8 Governor for bringing energy policy directly within his purview. In recognition of the  
9 change, the Task Force is submitting its report to the Governor's Office of Energy Policy,  
10 as it believes that this is the most appropriate venue for making recommendations with  
11 respect to energy issues in the Commonwealth.

12 The Task Force notes that its discussions covered topics that, while not within its original  
13 charge, are related to the improvement of energy efficiency with respect to housing and  
14 other structures. The Task Force has included some observations on these topics. They  
15 follow its formal recommendations.

## 17 **FINDINGS**

18  
19 Governor Fletcher has emphasized the importance of energy efficiency in the state's  
20 overall energy plan. The Task Force enthusiastically endorses this emphasis and  
21 encourages the Governor to continue to stress energy efficiency in his public statements  
22 and through policy initiatives. The Task Force also commends the Governor for his  
23 efforts to improve energy efficiency across all branches of state government and to  
24 establish inter-agency energy efficiency initiatives such as this. By making energy  
25 efficiency a high priority in its own operations, state government can serve as role model  
26 for local jurisdictions and for the private sector. We particularly commend Governor  
27 Fletcher for directing the Kentucky Education Cabinet to assist school districts in the  
28 design and construction of energy efficient facilities.

29 State government has the opportunity to attain substantial savings in energy costs through  
30 increasing the efficiency of state buildings. These savings can be used to improve other  
31 state services for the benefit of all Kentucky residents.



1 Kentucky's economy also can benefit from improvements in energy efficiency in housing  
2 and construction. Incorporation of energy-efficient features in new construction can  
3 create additional jobs and provide markets for new products that can be engineered and  
4 manufactured in Kentucky. Improving energy efficiency in existing structures offers  
5 similar opportunities.

6 Although Kentucky is fortunate to have some of the lowest energy costs in the nation,  
7 increasing energy efficiency nonetheless can provide significant savings. This would  
8 increase disposable income and increase economic activity. Furthermore, energy  
9 conservation can increase the supply of energy available for new economic growth  
10 without incurring the cost of providing new energy supply infrastructure.

11  
12 **RECOMMENDATION 1: State government can set a positive**  
13 **example by improving the energy efficiency of state buildings.**

14  
15 **Recommendation 1.1: State government should continue its efforts to reduce energy**  
16 **usage.**

17 The Task Force commends Governor Fletcher for Executive Order 2005-122,  
18 establishing the Utility Savings Council, which is charged with identifying opportunities  
19 to reduce utility costs in state government. The Utility Savings Council should be granted  
20 all the support necessary to achieve its goal of identifying measures that would reduce  
21 state energy costs by 10 percent.

22  
23 **Recommendation 1.2: Energy efficiency should be a key criterion in the design and**  
24 **construction of new state buildings or in any substantial renovation of existing**  
25 **buildings.**

26 A potential point of departure for setting criteria for state buildings or state-funded  
27 building projects is energy efficiency. The Task Force encourages the establishment of  
28 energy efficiency benchmarks, such as the U.S. Green Building Council's Leadership in  
29 Energy and Environmental Design (LEED) standards, Energy Star ratings or efforts  
30 similar to Montgomery County, Maryland.

1 **Recommendation 1.3: Continue to reduce the amount of energy used to light state**  
2 **facilities. This could be accomplished through building operating procedures and**  
3 **through expanded use of energy-efficient lighting technology.**

4 Examples include compact fluorescent bulbs, more efficient switching, daylighting use,  
5 occupancy sensors, task/ambient lighting separation, time clocks, photocells, other  
6 efficient lighting and modern building operating procedures. The Task Force commends  
7 Governor Fletcher for his support of the U.S. Environmental Protection Agency's  
8 ENERGY STAR *Change A Light, Change the World* campaign and hope that he will  
9 continue his strong advocacy through public service announcements and other means.

10  
11 **Recommendation 1.4: The Governor's Office of Energy Policy should continue to**  
12 **take a lead role in gathering information on best practices and advancements in**  
13 **energy efficiency and in disseminating that information throughout state**  
14 **government and to the public.**

15  
16 **Recommendation 1.5: The Finance and Administration Cabinet should continue to**  
17 **seek opportunities to improve the energy efficiency of the buildings under its**  
18 **management and should report regularly to the Governor on the progress in**  
19 **improving energy efficiency in state government.**

20  
21 **RECOMMENDATION 2: Promote energy efficiency in the**  
22 **construction of new homes and other buildings.**

23  
24 **Recommendation 2.1: Provide a means to inspect new home construction in areas of**  
25 **the Commonwealth where there is no local inspection program.**

26 More than half of Kentucky's local jurisdictions have no local residential building  
27 inspector. Therefore, many homes are not inspected for compliance with the Kentucky  
28 Residential Code, including provisions related to energy efficiency. While the current  
29 code is applicable to the entire state, the state inspectors do not have jurisdiction over  
30 single and two-family dwellings.

1 (A) Consideration should be given to establishing regional inspection capabilities,  
2 either through interlocal agreements or through the Office of Housing, Buildings  
3 and Construction (HBC) contracting with qualified vendors who will perform  
4 required inspections for a fee. The HBC could establish a price contract, and  
5 make inspection available in every county of the Commonwealth. This would  
6 not have a fiscal impact on city or county governments. Builders would pay a  
7 fee for the inspection.

8 (B) Two alternative options also merit consideration: Licensing and inspection of  
9 residential construction contractors, with violation of code potentially leading to  
10 disciplinary action; and inspection of heating, ventilation and air conditioning  
11 installation in a manner parallel to electrical or plumbing inspection, thus  
12 ensuring that HVAC systems are properly installed for efficient operation.

13  
14 **Recommendation 2.2: Consider the adoption of the 2006 International Residential**  
15 **Building Code, including Chapter 11 – Energy.**

16 Adoption of this code would place Kentucky at the cutting edge of energy efficiency in  
17 new home construction. The new code has improvements over the earlier versions and  
18 should be adopted in Kentucky. While some requirements of a more stringent energy  
19 code may increase construction costs, they may produce a net savings over the projected  
20 life of the structure. The Task Force understands that amendments to the code may be  
21 necessary in certain situations.

22  
23 **Recommendation 2.3: Consider creation of a tax credit for builders of ENERGY**  
24 **STAR new homes. Create a program to recognize builders meeting ENERGY STAR**  
25 **criteria.**

26 Under the federal Energy Policy Act of 2005 (EPACT 2005), a \$2000 tax credit is  
27 available for a new energy-efficient home that achieves 50 percent energy savings for  
28 heating and cooling over the 2004 International Energy Conservation Code (IECC). The  
29 Kentucky ENERGY STAR new home tax credit would complement the federal credit  
30 and create an incentive for Kentucky home builders to build a more energy-efficient  
31 home that would also qualify for the federal credit. While attaining the Energy Star

1 standard would increase the initial cost of a home, a recent University of Kentucky study  
2 showed that the monthly energy savings would exceed the additional mortgage cost.

3 The Task Force proposes an \$800 income tax credit to the builder for each certified  
4 home. Builders who meet or exceed an ENERGY STAR or LEED standard deserve  
5 additional recognition. This recognition could be tiered, based upon the number of homes  
6 constructed, Home Energy Rating System (HERS) rating, or other criteria, and should be  
7 subject to third-party validation. The positive publicity attendant to this recognition could  
8 provide an incentive for builders to improve energy efficiency.

9  
10 **Recommendation 2.4: Partner with the homebuilding industry to educate Kentucky**  
11 **builders on EPACT 2005 tax incentives for energy efficient new construction.**

12 The Governor’s Office of Energy Policy and the Office of Housing, Buildings and  
13 Construction can develop partnerships with the Homebuilders Associations across the  
14 Commonwealth to educate Kentucky’s builders on how to become eligible for federal tax  
15 credits for energy-efficient new construction. This educational effort would provide an  
16 opportunity for the Governor and other state government leaders to directly address  
17 members of a key economic sector and to emphasize the importance of energy efficiency  
18 to the continued health and growth of Kentucky’s economy.

19  
20 **Recommendation 2.5: Leverage existing economic development and workforce**  
21 **development programs to promote energy efficiency.**

22 Current low-interest business development loans can be used to assist new contractors  
23 wishing to provide services such as weatherization or remodeling designed to enhance  
24 energy efficiency.

25 Existing job-development and workforce training programs can be used to promote the  
26 development of industries manufacturing or installing energy-efficient components,  
27 equipment and building materials.

28

1 **RECOMMENDATION 3: Provide support and incentives for**  
2 **property owners to improve the efficiency of existing homes**  
3 **and other buildings**

4  
5 **Recommendation 3.1: Increase weatherization efforts across the Commonwealth,**  
6 **with particular emphasis on rental property.**

7 The Task Force recommends that state government convene a group that would address a  
8 number of key issues, including:

- 9 • Support of existing weatherization programs and expansion of their reach and  
10 effectiveness, including delivery of services to a broader range of Kentucky  
11 residents.  
12 • Effective provision of weatherization services to rental properties, including  
13 multi-family dwellings

14 Weatherization has the potential to provide the most rapid, enduring and cost-effective  
15 improvement in the energy efficiency of Kentucky’s housing inventory. Improvements  
16 such as additional insulation, modern windows and doors and more efficient HVAC  
17 systems have an immediate and lasting impact on energy consumption. Kentucky’s  
18 existing weatherization deliver a critically needed service but lack the resources to meet  
19 current demand. There is a substantial backlog of older homes in dire need of energy  
20 efficiency improvements. Furthermore, the assistance provided by weatherization  
21 programs accrues largely to Kentucky residents on low or fixed incomes – the segment of  
22 the population that would receive the greatest benefit from reduced residential utility  
23 costs.

24 The current federal funding framework for weatherization programs poses several  
25 challenges. Because it is directed at owner-occupied housing, relatively little flows into  
26 the rental housing sector, which serves a large proportion of low-income residents. In  
27 addition, income criteria for the program exclude many residents who would benefit from  
28 weatherization assistance and cannot themselves afford the necessary improvements.  
29 Increasing opportunities for weatherization assistance would assist many Kentuckians  
30 while making a significant impact on energy demand. The Task Force strongly supports

1 expanded weatherization programs that would serve low and moderate income families in  
2 both owner-occupied and rental housing. Recognizing that state funds are limited, the  
3 Task Force nonetheless believes that expanded financial resources for weatherization  
4 deserve consideration as a spending priority. A worthy goal would be to provide, by  
5 2016, weatherization services for every Kentucky household with an income below 150%  
6 of the poverty level. This could be accomplished by providing the necessary support to  
7 enable existing weatherization programs to expand their capacity, as well as the  
8 development of new entities, both public and private, to provide weatherization services.  
9 Weatherization programs also could improve home energy efficiency through new  
10 means, such as the replacement of older appliances with more efficient models.  
11 Because of the potential that expanded weatherization programs have to improve the lives  
12 of so many Kentuckians while benefiting the economy through the creation of jobs and  
13 the conservation of energy, we believe that they are deserving of special emphasis in the  
14 state's overall energy strategy.

15

16 **Recommendation 3.2: Provide homeowners with incentives to purchase energy-**  
17 **efficient homes and appliances and to make energy-conserving home improvements.**

18 (A) Possible incentives include tax credits, sales tax waivers, cash rebates, and low-  
19 interest loans for the purchase of energy-efficient equipment and supplies or other  
20 weatherization efforts.

21 (B) Energy Efficient Mortgages (EEM's) – an existing incentive provided through the  
22 federal Housing and Urban Development program and Fannie Mae - are rarely used in  
23 Kentucky. State government could work to identify any impediments to the use of EEM's  
24 in Kentucky and determine how to lower those barriers.

25 (C) Energy-efficiency development zones could be created in neighborhoods with older  
26 housing stock, with a time-delimited program of tax incentives to encourage energy-  
27 efficient retrofits of those homes.

28

29 **Recommendation 3.3: Provide homeowner incentives that would encourage the**  
30 **installation of renewable energy technologies such as solar electric (photovoltaic)**  
31 **systems and solar water heating systems.**

1 Solar energy systems have improved greatly in recent years and are becoming much more  
2 economically attractive options. They have the potential to significantly reduce electric  
3 demand, thus lowering strain on electric infrastructure, helping to defer the need for new  
4 facilities and thus helping to maintain low energy costs. Incentives for solar energy  
5 systems can include tax credits, rebates, credits for power sold onto the grid, or sales tax  
6 waivers on solar energy equipment. Such incentives may be coupled with initiatives to  
7 support the development of renewable energy businesses. These could include low-  
8 interest business development loans and incentives for solar equipment manufacturers to  
9 locate in Kentucky. Kentucky should consider augmenting the EPACT 2005 Federal  
10 Solar Tax Credits with a state tax credit of 30% of the cost of the system, up to \$1,000  
11 maximum credit.

12

### 13 **OBSERVATIONS ON RELATED TOPICS**

14

15 In the course of its deliberations, the Task Force discussed a number of topics that, while  
16 not included in its original agenda, are nonetheless germane to the question of how to  
17 improve energy efficiency in Kentucky.

18 Chief among these is the role that Kentucky’s energy providers, notably its electric  
19 utilities, can play in improving energy efficiency. As the Kentucky Public Service  
20 Commission (PSC) noted in its report entitled, “Kentucky’s Electric Infrastructure:  
21 Present and Future – An Assessment Conducted Pursuant to Executive Order 2005-121,”  
22 issued in August 2005, the cost of generating electricity will inevitably increase, making  
23 it more important for utilities to rely to a greater extent on energy efficiency and  
24 conservation as tools for managing demand. The Task Force concurs with this assessment  
25 and believes that there exist significant opportunities for state government to expand  
26 cooperation with both electric and natural gas utilities in Kentucky to promote efficiency  
27 and conservation.

28 We encourage both the PSC and the Governor’s Office on Energy Policy to continue  
29 their dialogue with Kentucky’s regulated utilities to identify the most effective strategies  
30 for advancing energy efficiency and conservation programs. We commend Governor  
31 Fletcher for directing the Office of Energy Policy to undertake a study that examines the

1 relationship between energy costs, as expressed in utility rates, and the efforts to improve  
2 energy efficiency and conservation. We strongly support efforts to maintain a regulatory  
3 climate in Kentucky that enables financially sound utilities to provide safe and reliable  
4 service at low cost, while at the same time promoting the use of energy in the most  
5 efficient manner possible.

6 The Task Force encourages the Governor's Office on Energy Policy to continue to  
7 engage Task Force members, either collectively or individually, to discuss Demand Side  
8 Management programs and alternative rate making strategies to determine whether they  
9 might be effective in reducing the demand for energy without increasing its price.

## 10 11 **CONCLUSION**

12 Efforts to improve energy efficiency and conservation must be an essential and central  
13 element of any sound, comprehensive, multi-faceted energy policy. The Task Force  
14 believes that improving the energy efficiency of housing and other buildings has the  
15 potential to make a significant contribution to the overall goal of an energy policy that  
16 maintains and improves the health of Kentucky's economy, its environment and its  
17 people.

18 The Task Force wishes to thank all those who contributed their time and effort,  
19 particularly LaJuana Wilcher, former Secretary of Environmental and Public Protection,  
20 under whose auspices it was convened, and former Commissioner for Public Protection  
21 Christopher Lilly, who served as its chairman.  
22



Subject: Re: Task Force letter and Minority Report

February 26, 2007

Commissioner Tim LeDonne  
Department of Public Protection  
100 Airport Road  
Frankfort, KY 40601

Dear Commissioner LeDonne:

At our meeting on February 13, 2007, it was argued that the issue of utility DSM programs was outside the bounds of the mandate given to the Task Force, as we were charged with addressing residential energy efficiency, not utility company issues. This perspective is very narrow and disregards the fact that electric and gas utilities and rate structures heavily influence energy use patterns in the residential sector. If our purpose was to recommend ways to improve home energy efficiency, it is clear that utility companies can play a powerful role in supporting this goal, and therefore the subject is relevant to the Task Force. We feel that Recommendations 4.1 and 4.2, listed below, are important strategies for improving residential energy efficiency.

Note that the Department's latest draft, while it excluded the section on utility DSM programs, retained the section on energy efficiency in state government facilities. One could argue that this Task Force was charged with addressing residential efficiency, not public sector efficiency, and that this section should therefore be deleted as well.

It is entirely appropriate to include government energy efficiency, however, for the reasons noted in the report - government should serve as a role model for homeowners and be good stewards of the taxpayer's resources.

If we accept the connection between government sector efficiency and residential efficiency, then there is no good reason to disregard the connection between energy utilities and residential energy efficiency.

The simple fact is that electric and gas utilities and the regulatory structure in which they operate play a major role in the patterns of energy use within the residential sector. To ignore this fact is to ignore one of the strongest tools we have for advancing the purpose of the Task Force.

With these thoughts in mind, we urge you to reconsider the draft Task Force report and recommendations and replace the section currently labeled "Observations on Related Topics" with the sections related to utility DSM programs (identified as Recommendation 4 below).

We also urge you to include the finding printed below, which discusses the importance of energy efficiency to the vitality of Kentucky's economy. This finding, which was removed from the November 2006 version, greatly strengthens these recommendations by demonstrating that efficiency is not simply a means to save homeowners money and protect the environment, but is an important part of a sustainable strategy for economic development.

If you choose not to reinstate these sections into the Final Report of the Task Force, we ask that you include the statement below, without alteration, as a Minority Report attached to the final Task Force report that will be released to the public.

Thank you,

Task Force members:

Geoffrey M. Young, Kentuckians for the Commonwealth  
Wallace McMullen, Kentucky Resources Council  
Andy McDonald, Appalachia - Science in the Public Interest  
James Dontje, PhD, Compton Chair in Ecological Design, Berea College  
Gary Watrous, AIA, LEED-AP, Watrous Associates Architects, PSC  
Mark Isaacs AIA, Architect/Builder, Legacy Homes

\*Minority Report of Advocates for Energy Efficiency and the Environment \* \*on the Energy Efficiency Task Force Convened by the \* \*Kentucky Department of Public Protection\*

The following statement reflects the views of the members of the Task Force representing certain organizations concerned about energy efficiency and the environment. At the penultimate meeting of the Task Force in November, 2006, substantial agreement was reached by all of the members present on the wording of the final report and recommendations.

Between November 2006 and February 2007, however, the report was completely reworked by the Department for Public Protection without the participation of the Task Force members. We are presenting this minority report because a major section of the November 2006 report was removed without our approval. Although we are in agreement with the intent of many of the recommendations in the first three sections of the department's final report, we are concerned that the excellent work done by the Task Force on issues related to the role of electric and natural gas utilities not be lost.

\*Additional Finding:\*

Improving energy efficiency is a key strategy to create a sustainable basis for Kentucky's economy. In addition to generating good jobs directly in construction, renovation, weatherization, engineering, design, and the manufacture of energy-efficient products and appliances, eliminating energy waste increases our disposable income, keeps money circulating within Kentucky, and makes our industries and products more competitive in the world market. Energy-efficient products manufactured in Kentucky and new design techniques developed here could be exported to the rest of the world. Efficiency improvements can make our energy available for economic growth without adding the cost of additional generation capacity. Saving energy is a win-win in all sectors of Kentucky's economy.

\*Recommendation 4:

Enlist Utility Companies in a Statewide Energy Efficiency Campaign.\*

\*Recommendation 4.1

Support Expanded Demand-Side Management (DSM) Programs in Kentucky.\*

Electric and natural gas utility companies can do much more to help customers reduce energy waste and lower their bills. Other states have achieved dramatic gains in energy efficiency through the use of initiatives known as Demand-Side Management (DSM) programs. Through state laws, regulations, and actions by the Public Service Commission (PSC), Kentucky can and should encourage the expansion of DSM programs covering all sectors of the economy.

Rationale: A wide range of technologies and design techniques now exist that can save electricity and natural gas, reduce customers' energy bills significantly, avoid or delay the need to construct expensive new power plants, and help protect the environment. Although some of Kentucky's utility companies have been operating DSM programs for years, these programs are small and limited in scope. Major opportunities to improve energy efficiency in the residential, commercial and industrial sectors are being ignored.

In addition to expanding Kentucky's existing DSM programs, utilities could implement programs to ensure that new homes, buildings and industrial plants are designed and built to standards that greatly exceed the minimum levels required by energy codes; to improve the performance of heating, ventilation and air conditioning (HVAC) systems in the field; to improve the efficiency of industrial motors, drives, pumping systems, and compressed air systems; and to work with manufacturing companies to install custom-designed manufacturing systems that are more energy-efficient and boost productivity and product quality as well. Non-regulated energy providers such as municipal utilities should also be brought on board to provide DSM programs for their customers.

\*Recommendation 4.2

Ensure that utility ratemaking formulas encourage energy efficiency.\*

Traditional ratemaking formulas link a utility's financial health to the volume of electricity or gas it sells and to the construction of new power plants, thus providing a strong incentive for them to sell more energy and a disincentive to invest in cost-effective DSM programs. When a utility helps customers save large amounts of energy, the utility is punished, in effect, with lower revenues and profits. The PSC needs to ensure that the utilities' most profitable investment strategy also leads them to provide energy services to their customers in the most efficient, affordable, and reliable way. Several other states are reforming their traditional electric and gas utility rate structures to align the utilities' incentives with the best interests of the public.

Kentucky should implement regulatory policies that:

- (1) remove utility disincentives by "decoupling" profits from sales volumes;
- (2) ensure that utilities recover their costs for effective, economic energy efficiency and clean, renewable programs; and
- (3) create incentives for utility managers and shareholders to invest in well-run and high-performing energy efficiency and renewable energy programs.



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

22. Refer to the Wesolosky Testimony, pages 6 through 11, and Exhibit MDW-1, concerning the proposed CEP. Has Delta performed the "California Tests" (Ratepayer Participant Test, Utility Cost Test, Ratepayer Impact Measure Test, and Total Resource Cost Test) to determine the cost effectiveness of this program?
- a. If yes, provide the results of each test. Include all workpapers, calculations, assumptions, and other supporting documentation.
  - b. If no, explain why Delta has not performed these tests. In addition, perform the tests and provide the results, including all workpapers, calculations, assumptions, and other supporting documentation.

RESPONSE:

a-b) The "California Tests" were performed, and the results were expressed on a net present value basis. The following summarizes the benefit-cost ratios for the respective tests:

<b>Test</b>	<b>Benefit-Cost Ratio</b>	<b>Exhibit</b>
Participant	3.33	1
Ratepayer Impact Measure	1.57	2
Total Resource Cost	1.07	3
Program Administrator	1.06	4

Since the benefit-cost ratio is greater than one, the CEP program, as designed, benefits the participant, ratepayer and program administrator, as well is a less expensive resource cost. See attached exhibits.

Sponsoring Witness:

Matthew D. Wesolosky

**Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Participant Test**

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$$NPV_P = B_P - C_P$$

$B_P = \$$	557,021
$C_P =$	167,506
$NPV_P = \$$	389,515

**Benefit-Cost Ratio** **3.33**

**Conclusion:**

Since the net present value is greater than zero, the program will benefit the participants

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Where:

- $NPV_P$  = Net present value to all participants
- $B_P$  = NPV of benefit to all participants
- $C_P$  = NPV of cost to all participants

$$B_P = \sum_{t=1}^N \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}}$$

$$C_P = \sum_{t=1}^N \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

- $BR_t$  = Bill reductions in year t
- $BI_t$  = Bill increases in year t
- $TC_t$  = Tax credits in year t
- $INC_t$  = Incentives paid to the participant by the Utility
- $PC_t$  = Participant costs in year t, which include incremental capital costs

The following calculations are based on the budgeted participation levels for year one of the program.

*See response 2d to the second PSC data request for the illustrative example of the rate mechanism which details the recoveries for year one of the program. This example includes the projected program expenditures and the calculations of commodity conservation.*

*Program budget and conservation estimates per appliance are included in the Program Document, submitted as Exhibit MDW-1 to the Wesolosky testimony.*

Delta Natural Gas Company, Inc.  
 Conservation/Efficiency Program  
 Participant Test

$$B_p = \sum_{t=1}^N \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}}$$

t	BR <sub>t</sub>	TC <sub>t</sub>	INC <sub>t</sub>	B <sub>p</sub>
1	63,290	64,500	120,400	248,190
2	62,202	-	-	62,202
3	60,792	-	-	60,792
4	59,664	-	-	59,664
5	58,858	-	-	58,858
6	58,496	-	-	58,496
7	58,818	-	-	58,818
8	58,455	-	-	58,455
9	57,488	-	-	57,488
10	57,327	-	-	57,327
	595,390	64,500	120,400	780,290

8.867% Discount Rate

\$557,021 NPV

- BR<sub>t</sub> = Bill reductions in year t
- TC<sub>t</sub> = Tax credits in year t
- INC<sub>t</sub> = Incentives paid to the participant by the Utility

Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Participant Test

$BR_t =$  Bill reductions in year t

t	(1) Ccf Conserved	(2) Projected Gas Cost*	(3) Proposed Demand Charge	(4) (2) + (3) Combined Rate	(1) x (4) BR <sub>t</sub>
1	40,289	\$ 1.155	\$ 0.4159	\$ 1.57	\$ 63,290
2	40,289	\$ 1.128	0.4159	1.54	62,202
3	40,289	\$ 1.093	0.4159	1.51	60,792
4	40,289	\$ 1.065	0.4159	1.48	59,664
5	40,289	\$ 1.045	0.4159	1.46	58,858
6	40,289	\$ 1.036	0.4159	1.45	58,496
7	40,289	\$ 1.044	0.4159	1.46	58,818
8	40,289	\$ 1.035	0.4159	1.45	58,455
9	40,289	\$ 1.011	0.4159	1.43	57,488
10	40,289	\$ 1.007	0.4159	1.42	57,327
					\$ 595,390

- (1) Total projected Ccf savings, based on budgeted participation levels in year one of the program. See KYPSC DR2-2d for calculation.
- (2) Based on Department of Energy "Annual Energy Outlook", converted to per ccf residential cost; where t = 1 = 2008
- (3) Volumetric charge proposed for residential customers in Case 2007-00089



Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Participant Test

$TC_t$  = Tax credits in year t

	(1) Program Participants	(2) Residential Energy Credits	(1) x (2) $TC_t$
<b><u>A. High Efficiency Heating Savings</u></b>			
1. High Efficiency Forced Air Furnaces	160	300	\$ 48,000
2. High Efficiency Dual Fuel Units	20	300	6,000
3. High Efficiency Gas Space Heating	20	-	-
4. High Efficiency Gas Logs/Fireplaces	340	-	-
<b><u>B. High Efficiency Water Heating Savings</u></b>			
1. High Efficiency Holding Tank Models	63	150	9,450
2. High Efficiency Power Vent Models	6	150	900
3. High Efficiency On-Demand Models	1	150	150
<b>Total</b>	<b>610</b>		<b>\$ 64,500</b>

*Note: participants are eligible for tax credits in the year they incur expenditures for high-efficiency appliances, since this is an analysis of participation in a single year, the tax credit is applicable only where  $t = 1$*

- (1) Based on budgeted participation levels in year one of the CEP.
- (2) Amount of tax credit per IRS Form 5695 for the 2006 tax year

Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Participant Test

$INC_t$  = Incentives paid to the participant by the Utility, for  $t = 1$

	(1) Program Participants	(2) Rebate Amount	(1) x (2) $INC_t$
<b><u>A. High Efficiency Heating Savings</u></b>			
1. High Efficiency Forced Air Furnaces	160	\$ 400	\$ 64,000
2. High Efficiency Dual Fuel Units	20	300	6,000
3. High Efficiency Gas Space Heating	20	100	2,000
4. High Efficiency Gas Logs/Fireplaces	340	100	34,000
<b><u>B. High Efficiency Water Heating Savings</u></b>			
1. High Efficiency Holding Tank Models	63	200	12,600
2. High Efficiency Power Vent Models	6	250	1,500
3. High Efficiency On-Demand Models	1	300	300
<b>Total</b>	<b>610</b>	<b>\$</b>	<b>120,400</b>

- (1) Based on budgeted participation levels in year one of the CEP.  
(2) Amount of rebate per CEP, per unit

*Note: rebates are given to participant in the year they elect to participate, since this is an analysis of participation in a single year, the rebate is applicable only where  $t = 1$*

Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Participant Test

$$C_p = \sum_{t=1}^N \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

t	(1) BI <sub>t</sub>	(2) PC <sub>t</sub>	(1) + (2) C <sub>p</sub>
1	4,188	177,060	181,248
2	342	-	342
3	342	-	342
4	342	-	342
5	342	-	342
6	-	-	-
7	-	-	-
8	-	-	-
9	-	-	-
10	-	-	-
	5,555	177,060	182,615

8.867% Discount Rate

\$167,506 NPV

BI<sub>t</sub> = Bill increases in year t

PC<sub>t</sub> = Participant costs in year t, which include  
incremental capital costs

Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Participant Test

$$Bl_t = PF \times CEPRC$$

t	(1) CEPCR	(2) CEPLS	(3) CEPI	(4) (1) + (2) + (3) CEPRC	(5) PF	(4) x (5) Bl <sub>t</sub>
1	167,120	16,756	21,416	205,292	0.0204	4,188
2		16,756		16,756	0.0204	342
3		16,756		16,756	0.0204	342
4		16,756		16,756	0.0204	342
5		16,756		16,756	0.0204	342
6				-	0.0204	-
7				-	0.0204	-
8				-	0.0204	-
9				-	0.0204	-
10				-	0.0204	-
	167,120	83,780	21,416	272,316		5,555

(1) - (3) Represents the individual components which comprise the CEP cost recovery. Amounts for year one are based on the year one program budget and expected participation.

For further explanation on the calculations behind (1) - (3) see the proposed tariff included with the filing requirements for Case 2007-00089

(1) CEPCR represents the program cost recovery of expenses for the given year. As noted this analysis is for a single year of participation, therefore the CEPCR is recovered where t=1.

(2) CEPLS represents the lost sales attributable to participation in the CEP. Lost sales for a given year are recovered annually through the CEP mechanism until the next general rate case when rates can be reset. Since this analysis is for a single year of participation the lost sales remain constant until the next general rate case. For the purpose of this analysis the next general rate case anticipated in five years based on the requirements of the proposed CRS tariff.

(3) CEPI represents the incentive earned by the company based on the conservation in the given year. As noted this analysis is for a single year of participation, therefore the CEPI is recovered where t=1.

(5) Bl<sub>t</sub> represents the impact of increased rates on the program participants. Since the CEPRC is recovered from all residential customers, a factor was applied to determine the amount of impact to the CEP participants. This is a ratio of participants to the number of residential customers as of 12/31/06.

A	656	Budgeted CEP participants (year 1)
B	32,115	total residential customers, per Seelye Exhibit 4
A/B	0.0204	Participant Factor (PF)

Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Participant Test

$PC_t$  = Participant costs for  $t = 1$

	(1) Program Participants	(2) Incremental Cost	(1) x (2) $PC_t$
<b><u>A. High Efficiency Heating Savings</u></b>			
1. High Efficiency Forced Air Furnaces	160	\$ 613	\$ 98,080
2. High Efficiency Dual Fuel Units	20	613	12,260
3. High Efficiency Gas Space Heating	20	143	2,860
4. High Efficiency Gas Logs/Fireplaces	340	143	48,620
<b><u>B. High Efficiency Water Heating Savings</u></b>			
1. High Efficiency Holding Tank Models	63	187	11,781
2. High Efficiency Power Vent Models	6	455	2,730
3. High Efficiency On-Demand Models	1	729	729
<b>Total</b>	<b>610</b>	<b>\$</b>	<b>177,060</b>

IC = Incremental Costs for purchasing high-efficiency unit

- (1) Based on budgeted participation levels in year one of the CEP.
- (2) Incremental costs, per KYPSC DR2-23b

Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Ratepayer Impact Measure (RIM) Test

$$NPV_{RIM} = B_{RIM} - C_{RIM}$$

$B_{RIM} =$	\$	517,594
$C_{RIM} =$		329,503
$NPV_{RIM} =$	\$	<b>188,091</b>

**Benefit-Cost Ratio** 1.57

**Conclusion:**

Since the net present value is greater than zero, the program will benefit rates and bills

Where:

- $NPV_{RIM}$  = Net present value levels
- $B_{RIM}$  = Benefits to rate levels or customer bills
- $C_{RIM}$  = Costs to rate levels or customer bills

$$B_{RIM} = \sum_{t=1}^N \frac{UAC_t + RG_t}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^N \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}}$$

- $UAC_t$  = Utility avoided supply costs in year t
- $UIC_t$  = Utility increased supply costs in year t
- $RG_t$  = Revenue gain from increased sales in year t
- $RL_t$  = Revenue loss from reduced sales in year t
- $PRC_t$  = Program administrator costs in year t
- $INC_t$  = Incentives paid to the participant by the sponsoring utility in year t

The following calculations are based on the budgeted participation levels for year one of the program.

*See response 2d to the second PSC data request for the illustrative example of the rate mechanism which details the recoveries for year one of the program. This example includes the projected program expenditures and the calculations of commodity conservation.*

*Program budget and conservation estimates per appliance are included in the Program Document, submitted as Exhibit MDW-1 to the Wesolosky testimony.*

Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Ratepayer Impact Measure (RIM) Test

$$B_{RIM} = \sum_{t=1}^N \frac{UAC_t + RG_t}{(1+d)^{t-1}}$$

t	UAC <sub>t</sub>	RG <sub>t</sub>	B <sub>RIM</sub>
1	46,534	205,292	251,826
2	45,446	16,756	62,202
3	44,036	16,756	60,792
4	42,908	16,756	59,664
5	42,102	16,756	58,858
6	41,739	-	41,739
7	42,062	-	42,062
8	41,699	-	41,699
9	40,732	-	40,732
10	40,571	-	40,571
	427,829	272,316	700,145

8.867% Discount Rate

\$517,594 NPV

- UAC<sub>t</sub> = Utility avoided supply costs in year t
- RG<sub>t</sub> = Revenue gain from increased sales in year t

Delta Natural Gas Company, Inc.  
 Conservation/Efficiency Program  
 Ratepayer Impact Measure (RIM) Test

$UAC_t =$  Utility avoided supply costs in year t

t	(1) Ccf Conserved	(2) Projected Gas Cost*	(1) x (2) UAC <sub>t</sub>
1	40,289	\$ 1.155	\$ 46,534
2	40,289	\$ 1.128	\$ 45,446
3	40,289	\$ 1.093	\$ 44,036
4	40,289	\$ 1.065	\$ 42,908
5	40,289	\$ 1.045	\$ 42,102
6	40,289	\$ 1.036	\$ 41,739
7	40,289	\$ 1.044	\$ 42,062
8	40,289	\$ 1.035	\$ 41,699
9	40,289	\$ 1.011	\$ 40,732
10	40,289	\$ 1.007	\$ 40,571
			\$ 427,829

- (1) Total projected Ccf savings, based on budgeted participation levels in year one of the program. These amounts continue to be saved year after year.
- (2) Based on Department of Energy "Annual Energy Outlook", converted to per ccf residential cost; where t = 1 = 2008
- (3) Volumetric charge proposed for residential customers in Case 2007-00089

Note: the above analysis is based on the CCF conserved from a single year of participation in the CEP



Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Ratepayer Impact Measure (RIM) Test

$RG_t$  = Revenue gain from increased sales in year t

t	(1) CEPCR	(2) CEPLS	(3) CEPI	$RG_t$
1	167,120	16,756	21,416	205,292
2		16,756		16,756
3		16,756		16,756
4		16,756		16,756
5		16,756		16,756
6				-
7				-
8				-
9				-
10				-
	167,120	83,780	21,416	272,316

(1) - (3) Represents the individual components which comprise the CEP cost recovery. Amounts for year one are based on the year one program budget and expected participation.

For further explanation on the calculations behind (1) - (3) see the proposed tariff included with the filing requirements for Case 2007-00089

- (1) CEPCR represents the program cost recovery of expenses for the given year. As noted this analysis is for a single year of participation, therefore the CEPCR is recovered where  $t=1$ .
- (2) CEPLS represents the lost sales attributable to participation in the CEP. Lost sales for a given year are recovered annually through the CEP mechanism until the next general rate case when rates can be reset. Since this analysis is for a single year of participation the lost sales remain constant until the next general rate case. For the purpose of this analysis the next general rate case anticipated in five years based on the requirements of the proposed CRS tariff.
- (3) CEPI represents the incentive earned by the company based on the conservation in the given year. As noted this analysis is for a single year of participation, therefore the CEPI is recovered where  $t=1$ .

Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Ratepayer Impact Measure (RIM) Test

$$C_{RIM} = \sum_{t=1}^N \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}}$$

t	(1) UIC <sub>t</sub>	(2) RL <sub>t</sub>	(3) PRC <sub>t</sub>	(4) INC <sub>t</sub>	(1) + (2) C <sub>RIM</sub>
1	-	16,756	167,120	120,400	304,276
2	-	16,756	-	-	16,756
3	-	16,756	-	-	16,756
4	-	16,756	-	-	16,756
5	-	16,756	-	-	16,756
6	-	-	-	-	-
7	-	-	-	-	-
8	-	-	-	-	-
9	-	-	-	-	-
10	-	-	-	-	-
	-	83,780	167,120	120,400	250,900

8.867% Discount Rate

\$329,503 NPV

- UIC<sub>t</sub> = Utility increased supply costs in year t
- RL<sub>t</sub> = Revenue loss from reduced sales in year t
- PRC<sub>t</sub> = Program administrator costs in year t
- INC<sub>t</sub> = Incentives paid to the participant by the sponsoring utility in year t

- (1) No known increased supply costs
- (2) see RG; column (2)
- (3) see RG; column (3)
- (4) Scheduled per calculation performed for Participant Test

Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Total Resource Cost (TRC) Test

$$NPV_{TRC} = B_{TRC} - C_{TRC}$$

$B_{TRC} =$	\$	338,260
$C_{TRC} =$		316,147
$NPV_{TRC} =$	\$	22,113

**Benefit-Cost Ratio** 1.07

**Conclusion:**

Since the net present value is greater than zero, the program is a less expensive resource than the supply option upon which the marginal costs are based.

Where:

$NPV_{TRC}$  = Net present value of total cost of the resource

$B_{TRC}$  = NPV of benefits of the program

$C_{TRC}$  = NPV of costs of the programs

$$B_{TRC} = \sum_{t=1}^N \frac{UAC_t + TC_t}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^N \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$UAC_t$  = Utility avoided supply costs in year t

$TC_t$  = Tax credits in year t

$UIC_t$  = Utility increased supply costs in year t

$PRC_t$  = Program administrator costs in year t

$PCN_t$  = Net participant costs

The following calculations are based on the budgeted participation levels for year one of the program.

Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Total Resource Cost (TRC) Test

$$B_{TRC} = \sum_{t=1}^N \frac{UAC_t + TC_t}{(1+d)^{t-1}}$$

t	(1) UAC <sub>t</sub>	(2) TC <sub>t</sub>	B <sub>TRC</sub>
1	46,534	64,500	111,034
2	45,446	-	45,446
3	44,036	-	44,036
4	42,908	-	42,908
5	42,102	-	42,102
6	41,739	-	41,739
7	42,062	-	42,062
8	41,699	-	41,699
9	40,732	-	40,732
10	40,571	-	40,571
	427,829	64,500	492,329

8.867% Discount Rate

\$338,260 NPV

UAC<sub>t</sub> = Utility avoided supply costs in year t  
TC<sub>t</sub> = Tax Credits in year t

- (1) Scheduled per calculation performed for RIM Test
- (2) Scheduled per calculation performed for Participant Test

Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Total Resource Cost (TRC) Test

$$C_{TRC} = \sum_{t=1}^N \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

t	(1) PRC <sub>t</sub>	(2) PCN <sub>t</sub>	(3) UIC <sub>t</sub>	C <sub>TRC</sub>
1	167,120	177,060	-	344,180
2	-	-	-	-
3	-	-	-	-
4	-	-	-	-
5	-	-	-	-
6	-	-	-	-
7	-	-	-	-
8	-	-	-	-
9	-	-	-	-
10	-	-	-	-
	167,120	177,060	-	344,180

8.867% Discount Rate

\$316,147 NPV

- PRC<sub>t</sub> = Program administrator costs in year t  
 PCN<sub>t</sub> = Net participant costs  
 UIC<sub>t</sub> = Utility increased supply costs in year t

- (1) Scheduled per calculation performed for RIM Test
- (2) Represents net participant costs which is the incremental cost to the participant of purchasing a high-efficiency appliance versus one with standard efficiency. Amount scheduled from PC<sub>t</sub> from the Participant Test.
- (3) No known increased supply costs as a result of operating the CEP



**Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Program Administrator Cost Test**

$$B_{pa} = \sum_{t=1}^N \frac{UAC_t}{(1+d)^{t-1}}$$

(1)

t	UAC <sub>t</sub>
1	\$ 46,534
2	\$ 45,446
3	\$ 44,036
4	\$ 42,908
5	\$ 42,102
6	\$ 41,739
7	\$ 42,062
8	\$ 41,699
9	\$ 40,732
10	\$ 40,571
	<u>\$ 427,829</u>

8.867% Discount Rate

\$279,013 NPV

(1) UAC<sub>t</sub> scheduled per calculation performed for RIM test

UAC<sub>t</sub> = Utility avoided supply costs in year t

Delta Natural Gas Company, Inc.  
Conservation/Efficiency Program  
Program Administrator Cost Test

$$C_{pa} = \sum_{t=1}^N \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

t	(1) PRC <sub>t</sub>	(2) INC <sub>t</sub>	(3) UIC <sub>t</sub>	C <sub>pa</sub>
1	167,120	120,400	-	287,520
2	-	-	-	-
3	-	-	-	-
4	-	-	-	-
5	-	-	-	-
6	-	-	-	-
7	-	-	-	-
8	-	-	-	-
9	-	-	-	-
10	-	-	-	-
	167,120	120,400	-	287,520

8.867% Discount Rate

\$264,102 NPV

- PRC<sub>t</sub> = Program Administrator Costs in year t  
 INC<sub>t</sub> = Incentives paid to the participant by the Utility  
 UIC<sub>t</sub> = Utility increased supply costs in year t

- (1) Program costs scheduled from PRC<sub>t</sub> which was calculated for the RIM Test  
 (2) Incentives scheduled from INC<sub>t</sub> which was calculated for the Participant test  
 (3) No known increased supply costs as a result of operating the CEP





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23. Refer to the Wesolosky Testimony, pages 7 and 8. Delta states that the rebate on high efficiency appliances assists customers in paying the incremental costs of high energy appliances.
- a. Explain how Delta determined the amount of the rebates shown on pages 6 and 8 of Exhibit MDW-1.
  - b. Identify and describe the incremental costs associated with the purchase of a high efficiency appliance.
  - c. How do the rebates proposed by Delta compare with these incremental costs?
  - d. Will all customers be responsible for paying for Delta's lost revenues under the CEP or just the customers who participate in the program?
  - e. Delta's proposed CEP includes an incentive to administer the program. If the mechanism allows Delta to recover its lost revenues, explain why it also needs an incentive within the program.
  - f. Explain how Delta determined that its incentive for administering the CEP should be 15 percent.
  - g. Delta states that it expects participation in the CEP to increase. Explain in detail the basis for this expectation. Include copies of any studies or analyses performed by or for Delta.
  - h. Delta states that its proposed CEP mechanism has been modeled after other demand-side management ("DSM") rate mechanisms previously approved by the Commission and currently in effect. Identify the utilities.

**RESPONSES:**

- a. The rebate amounts were developed based on the incremental equipment cost associated with the purchase of a high efficiency appliance. These amounts were selected to create the most advantageous assistance to the participant while still ensuring the "California Tests" had a benefit cost ratio greater than one as to not be a detriment to the ratepayers or program administrator.

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- b. The incremental cost associated with the purchase of a high efficiency appliance is the average incremental cost to purchase an appliance which is deemed to be “high efficiency” as compared to an appliance with “standard efficiency”. The CEP program document which was filed as Exhibit MDW-1 to the Wesolosky testimony details the distinction between standard and high efficiency for the purposes of the program. Attached is a cost study performed by Delta which is a comparison of prices for standard efficiency versus high efficiency appliances.
- c. Please refer to the table below for a comparison of the CEP rebates to the incremental equipment cost.

	<u>Rebate</u>	<u>Incremental Cost</u>
<b><u>A. High Efficiency Heating</u></b>		
1. High Efficiency Forced Air Furnaces	\$ 400	\$ 613
2. High Efficiency Dual Fuel Units	300	613
3. High Efficiency Gas Space Heating	100	143
4. High Efficiency Gas Logs/Fireplaces	100	143
<b><u>B. High Efficiency Water Heating</u></b>		
1. High Efficiency Holding Tank Models	200	187
2. High Efficiency Power Vent Models	250	455
3. High Efficiency On-Demand Models	300	729

- d. Yes, all customers will be responsible for the lost sales component of the rate mechanism.
- e. If Delta had a CEP where only lost sales from conservation under the program were recovered, the CEP would be revenue neutral to Delta and there would be no prudent business reason to undertake the program without an incentive.
- f. The fifteen percent was based on regulatory precedence. Currently, the following DSM programs approved by the Commission earn a 15% incentive: Louisville Gas and Electric, Kentucky Utilities, and Duke Energy – Kentucky.
- g. Delta has not performed any studies related to the participation levels. The initial participation levels were created based on discussions with our Customer Development and Customer Service Departments and their expectations related to utilization by new and existing customers. We do not have detailed and complete records relating to our customer’s appliance mix, so assumptions relating to appliance mix had to be made for the purposes of budgeting participation. It should be noted that virtually all estimated costs associated with the CEP are variable costs which will fluctuate with participation levels. Therefore, there is no detriment to Delta or its customers if actual participation levels are less than budgeted.

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The assumption that participation will increase is based on our assumption that over time there will be increased awareness of the program by our customer base and therefore increased utilization of the program.

- h. Currently, there are no other gas DSM programs within the Commonwealth of Kentucky. However, the methodology and recovery of such a program has been modeled after the DSM rate mechanisms of Louisville Gas and Electric, Kentucky Utilities, and Duke Energy – Kentucky.

Sponsoring Witness:

Matthew D. Wesolosky

Delta Natural Gas Company, Inc.  
 Conservation Efficiency Program  
 Appliance Cost Study  
 High Efficiency Natural Gas Furnace Unit Cost Comparison

Supplier	Equipment Brand	Unit Sizing	Incremental Cost*		
			Low	High	Average
Vendor A London, Kentucky	York	2,000 sq ft	\$ 384	\$ 500	\$ 442
Vendor B Berea, Kentucky	Trane	2,000 sq ft	400	600	500
Vendor C Morehead, Kentucky	Lennox	2,000 sq ft	600	800	700
Vendor D Richmond, Kentucky	Lennox	2,000 sq ft	800	1,000	900
Vendor E Lexington, Kentucky	Tempstar	2,000 sq ft	525	525	<u>525</u>
Average Incremental Cost					613

\*Pricing for incremental cost based comparison of furnace rated with 80% efficiency, as compared to same model with 90% efficiency

For the purposes of determining the incremental costs Delta has assumed the same incremental cost for dual fuel units as a dual fuel unit still requires the purchase of a natural gas furnace

Delta Natural Gas Company, Inc.  
 Conservation Efficiency Program  
 Appliance Cost Study  
 High Efficiency Natural Gas Water Heater Cost Comparison

HVAC Contractor	Equipment Brand	Unit Sizing	Pricing		
			Unit	Average	Incremental
<b>Standard Efficiency Holding Tank</b>					
Vendor A	Whirlpool - Flamelock	30 gallon	\$ 245		
Vendor A	Whirlpool - Flamelock	40 gallon	294		
Vendor B	Bradford White	50 gallon	269		
				\$ 269	
<b>High Efficiency Holding Tank</b>					
Vendor A	Whirlpool Energy Smart	40 gallon	\$ 449		
Vendor A	Whirlpool Energy Smart	40 gallon	486		
Vendor A	US Craftmaster	50 gallon	434		
				\$ 456	\$ 187
<b>Power Vent</b>					
Vendor C	AO Smith Power Vent	50 gallon	\$ 750		
Vendor A	PowerFlex	40 gallon	737		
Vendor A	PowerFlex	50 gallon	686		
				\$ 724	\$ 455
<b>On-Demand</b>					
Vendor A	Bosch - AquaStar	175,000 BTUs	\$ 998		
Vendor D	Bosch - AquaStar	175,000 BTUs	997		
Vendor D	Paloma - PTG-74PVNH	199,900 BTUs	999		
				\$ 998	\$ 729

Delta Natural Gas Company, Inc.  
 Conservation Efficiency Program  
 Appliance Cost Study  
 High Efficiency Gas Log Cost Comparison

Supplier	Brand	Vented		Un-Vented			Incremental Cost	
		Unit Sizing	Unit Cost	Brand	Unit Sizing	Unit Cost		
Vendor A	Eiklor	24 inch	\$ 603	Empire	24 inch	\$ 649	\$ 46	
Vendor B	Peterson	24 inch	335	Monesson	24 inch	499	164	
Vendor C	Peterson	24 inch	384	Peterson	24 inch	604	220	
<b>Average Incremental Cost</b>							<b>\$</b>	<b>143</b>

**Natural Gas Space Heating**

Pricing for space heating appliances, was not readily available. Since natural gas space heating is often utilized to replace wood burning stoves, wood burning fireplaces and vented fireplaces, the same incremental cost has been assumed. Delta feels this is a conservative estimate since there is no equipment cost associated with wood burning applications.





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24. Refer to the Wesolosky Testimony, pages 8 and 9, Exhibit MDW-1, and the Application, Tab 7, Sheet Nos. 38 through 41. Concerning the proposed CEP incentive, provide Delta's calculation of the present value of the expected commodity savings generated in excess of the CEP costs, as referenced.

**RESPONSE:**

Please refer to the schedules provided in response to item 2d of the Second PSC Data Request. This schedule includes an illustrative example of the calculations for the CEP Incentive.

Sponsoring Witness:

Matthew D. Wesolosky



**DELTA NATURAL GAS COMPANY, INC.**  
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25. Refer to the Wesolosky Testimony, page 11. Provide the calculation of Delta's conservation estimate for the energy audits.

RESPONSE:

Per the CEP guidelines in Exhibit MDW-1, the conservation estimate for energy audits is 30 ccf. Attached is a copy of the Energy Information Administration Household Energy Consumption and Expenditures Study performed in 2001 on data through 1997. The study shows that for a customer in the South Census Region, whose primary space heating fuel is natural gas, 3,000 cubic feet (30 Ccf) of natural gas can be conserved per year by lowering the thermostat setting by 1 degree.

As noted in KYPSC DR2-2b actual conservation of natural gas cannot be accurately measured at the meter due to other variables. Therefore Delta's conservation estimate for an energy audit is the estimated impact of lowering the thermostat by one degree. We have determined this to be conservative, because it is an action item which any CEP participant can do at no cost to themselves. However, we are cognizant that actual energy savings will be greater as participants will be given additional information as to how they can take specific actions in their home to conserve energy (i.e. weather stripping, insulation, water heater setting, etc).

Sponsoring Witness

Matthew D. Wesolosky

**Table 3. Dollars Saved per Household for a 1° F Lower Thermostat Setting by Division in the South Census Region, 1997**

	South Census Region					RSE Row Factors
	Total U.S.	Census Division			West South Central	
		Total	South Atlantic	East South Central		
RSE Column Factor:	0.5	0.9	1.2	1.0	1.9	
Million Households						
Total U.S. Households .....	101.5	35.9	18.7	6.3	10.8	NF
Number of Households, Where the Main Space-Heating Fuel Is:						
Electricity .....	29.6	17.5	10.4	2.9	4.2	7.2
Natural Gas .....	53.5	13.7	5.4	2.3	6.1	7.5
Fuel Oil .....	9.5	1.1	1.1	Q	Q	26.7
Kerosene .....	1.0	0.4	0.4	Q	Q	20.2
LPG .....	4.6	2.1	0.8	0.8	0.4	18.1
1997 Heating Degree-Days (HDD65) per Household <sup>1</sup>						
1997 Heating Degree-Days (HDD65) per Household, Where the Main Space-Heating Fuel Is:						
Electricity .....	3,225	2,382	2,110	3,403	2,346	6.3
Natural Gas .....	4,710	2,970	3,197	3,326	2,637	5.6
Fuel Oil .....	5,707	3,857	3,844	Q	Q	6.9
Kerosene .....	4,959	3,010	2,871	Q	Q	10.1
LPG .....	4,863	2,991	2,832	3,250	2,766	9.5
Physical Units per Household <sup>1</sup>						
Physical Units of Space-Heating Consumption per Household, <sup>2</sup> Where the Main Space-Heating Fuel Is:						
Electricity (kWh) .....	3,760	3,319	2,829	5,207	3,221	6.3
Natural Gas (thousand cf) .....	65	49	51	53	46	6.7
Fuel Oil (gallons) .....	636	469	462	Q	Q	6.3
Kerosene (gallons) .....	307	190	167	Q	Q	18.1
LPG (gallons) .....	585	418	481	388	350	9.6
Dollars per Household (1997) <sup>1</sup>						
Space-Heating Expenditures per Household, <sup>3</sup> Where the Main Space-Heating Fuel Is:						
Electricity .....	270	233	213	312	230	5.9
Natural Gas .....	446	358	432	367	288	5.8
Fuel Oil .....	629	518	516	Q	Q	6.4
Kerosene .....	350	221	196	Q	Q	19.0
LPG .....	567	451	553	408	330	8.4
Dollars per Household (2000-2001 Estimates) <sup>1</sup>						
Space-Heating Expenditures per Household, <sup>3</sup> Where the Main Space-Heating Fuel Is:						
Electricity .....	264	229	208	306	225	5.9
Natural Gas .....	678	544	657	558	438	5.8
Fuel Oil .....	881	725	722	Q	Q	6.4
Kerosene .....	489	310	275	Q	Q	19.0
LPG .....	726	578	708	522	422	8.4

See footnotes at end of table.

**Table 3. Dollars Saved per Household for a 1° F Lower Thermostat Setting by Division in the South Census Region, 1997 (Continued)**

	South Census Region					RSE Row Factors
	Total U.S.	Census Division				
		Total	South Atlantic	East South Central		
RSE Column Factor:	0.5	0.9	1.2	1.0	1.9	
<b>SAVINGS: Physical Units per Household<sup>1</sup></b>						
Physical Units of Space-Heating Consumption per Household (SAVINGS), <sup>2</sup> Where the Main Space-Heating Fuel Is:						
Electricity (kWh) .....	215	209	184	297	209	5.5
Natural Gas (thousand cf) .....	3	3	3	3	3	4.3
Fuel Oil (gallons) .....	28	26	25	Q	Q	5.9
Kerosene (gallons) .....	14	12	11	Q	Q	17.0
LPG (gallons) .....	27	25	31	23	20	7.6
<b>SAVINGS: Dollars per Household (1997)<sup>1</sup></b>						
Space-Heating Expenditures per Household (SAVINGS), <sup>3</sup> Where the Main Space-Heating Fuel Is:						
Electricity .....	16	15	14	18	15	5.8
Natural Gas .....	22	22	26	22	18	4.9
Fuel Oil .....	28	28	28	Q	Q	5.8
Kerosene .....	16	14	13	Q	Q	18.2
LPG .....	27	28	36	24	19	6.4
<b>SAVINGS: Dollars per Household (2000-2001 Estimates)<sup>1</sup></b>						
Space-Heating Expenditures per Household (SAVINGS), <sup>3</sup> Where the Main Space-Heating Fuel Is:						
Electricity .....	15	15	14	18	15	5.8
Natural Gas .....	33	33	40	33	27	4.9
Fuel Oil .....	39	40	40	Q	Q	5.8
Kerosene .....	23	19	18	Q	Q	18.2
LPG .....	35	35	46	30	24	6.4
<b>Percent Savings<sup>1</sup></b>						
Space-Heating Btu Consumption per Household (PERCENT), <sup>2</sup> Where the Main Space-Heating Fuel Is:						
Electricity .....	5.72	6.29	6.49	5.71	6.49	2.9
Natural Gas .....	4.76	5.97	6.01	5.81	6.00	3.4
Fuel Oil .....	4.44	5.50	5.52	Q	Q	3.7
Kerosene .....	4.69	6.13	6.39	Q	Q	4.7
LPG .....	4.65	6.05	6.40	5.80	5.65	4.8

<sup>1</sup> Averages are for those households using each of the main space-heating fuels.

<sup>2</sup> Includes only the space-heating consumption of the space-heating fuel. Not included are: 1) the consumption of the main space-heating fuel for uses other than space heating; 2) the consumption of the main space-heating fuel where it is the secondary, and not the main, space-heating fuel, and; 3) the consumption of other fuels that are used as secondary space-heating fuels.

<sup>3</sup> Includes only the space-heating expenditures of the space-heating fuel. Not included are: 1) the expenditures of the main space-heating fuel for uses other than space heating; 2) the expenditures of the main space-heating fuel where it is the secondary, and not the main, space-heating fuel, and; 3) the expenditures of other fuels that are used as secondary space-heating fuels.

NF = No applicable RSE row factor.

Q = Data withheld either because the Relative Standard Error (RSE) was greater than 50 percent or fewer than 10 households were sampled.

Notes: • To obtain the RSE percentage for any table cell, multiply the corresponding column and row factors. • Because of rounding, data may not sum to totals. • See "Glossary" for definition of terms used in this report.

Source: Energy Information Administration, Office of Energy Markets and End Use, Forms EIA-457 A-G of the 1997 Residential Energy Consumption Survey, and EIA, Short-Term Integrated Forecasting system database, February 2001.



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26. Refer to the Wesolosky Testimony, Exhibit MDW-1.
- a. On page 3 is a statement that Delta had previously developed and offered a home energy audit program at no cost to the customer.
    - (1) Provide a description of this home energy audit program.
    - (2) Indicate the years the program was in effect.
    - (3) Indicate the number of audits performed each year the program was in effect.
    - (4) Provide the annual cost of the audits.
    - (5) If the audit program has been discontinued, explain why the program was discontinued.
  
  - b. On page 11 is a statement that the energy audit is a service provided at no cost to any Delta customer classified as residential or small commercial. However, the proposed CEP tariff on Sheet No. 38 states the tariff is for residential customers only.
    - (1) Indicate whether the energy audit will be available to small commercial customers.
    - (2) If the energy audit will be available to small commercial customers, explain why the proposed CEP tariff is not applicable to that customer class.
  
  - c. Page 12 presents the projected participation in the proposed CEP from 2008 through 2017. Explain in detail how Delta determined the number of heating units, water heaters, and energy audits. Include all workpapers, calculations, assumptions, and other supporting documentation.
  
  - d. Page 13 presents the program budgeted expenditures for the proposed CEP. Explain how Delta determined the amounts for each line item of the expenditures. Include all workpapers, calculations, assumptions, and other supporting documentation.
  
  - e. Page 15 describes the lost sales recovery portion of the cost recovery mechanism. Will lost sales be determined on the customer awareness portion of the proposed CEP? If yes, explain how this will be determined.
  
  - f. Is Delta's proposed CEP consistent with its most recent long-range integrated resource plan? Explain the response.

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- g. Were customer representatives and the AG involved in the development of the proposed CEP?
- (1) If yes, identify the customer representatives involved and describe the level of involvement of those representatives and the AG in developing the proposal.
  - (2) If no, explain why customer representatives and the AG were not involved.

RESPONSE:

- a. (1) Delta's current home energy audit program covers the very basics of energy conservation through a one hour inspection process and findings review. The consumer is provided with a number of energy savings tips and recommendations to help lower their current consumption. We have the customer accompany the energy inspector and observe insulation levels, door and window seals, furnace maintenance, thermostat settings, duct and ventilation system and other possible deficiencies that, if corrected, could lower energy use. The audit is performed at no cost to any of Delta's customers.
- (2) The program has been in effect since 2003.
- (3) As the program is informal in nature detailed statistics on the program are not maintained. However, it is estimated that approximately ten to thirty audits are performed annually based on the demand.
- (4) As previously noted, the program is informal in nature. There are no direct costs associated with the program. The labor costs associated with the audit are not tracked separately.
- (5) The program has not been discontinued.
- b. The statement was in error. The CEP would only be offered to residential customers. Because we believe there is a large demand for such a program, we expect the residential class to utilize the program to its fullest extent. It is our intention as the program matures to seek approval from the Commission to include small non-residential customers.
- c. Please refer to KYPSC DR2-23(g)
- d. Please refer to the attached budget.



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- e. No. To be conservative in our estimates related to lost sales, we did not include for the recovery of lost sales due to customer awareness. Customer awareness is integral in promoting conservation and efficiency. However, Delta cannot estimate with any precision the estimated conservation from promoting general customer awareness.
- f. Delta does not have a long-range integrated resource plan, as this is required by the Commission for electric utilities under 807 KAR 5:058.
- g.
  - 1-2) KRS 278.285 allows for a DSM program to be approved in conjunction with rate schedules initiated pursuant to KRS 278.190. Therefore, we determined our rate case would be the appropriate forum to present the CEP. Additionally, the rate case would provide the Office of the Attorney General and other customer representatives the opportunity to provide feedback on the program, pursuant to subsection 1(f) of the KRS.

Sponsoring Witness:

Matthew D. Wesolosky

**Delta Natural Gas Company, Inc.**  
**CEP**  
**Budgeted Expenditures**

		<b>Schedule</b>
Heating Rebates		
Forced Air Furnace	\$ 64,000	1
Dual Fuel Units	6,000	1
Gas Space Heating	2,000	1
Gas Logs/Fireplaces	34,000	1
Water Heater Rebates		
Holding Tank	12,600	1
Power Vent	1,500	1
On-Demand	300	1
Residential Energy Audits	920	2
Program Advertising	25,000	3
Infrared Thermal Camera*	10,000	
Labor	10,000	4
Office Expenses**	800	
<b>Total Expenses per CEP Budget</b>	<b><u>\$ 167,120</u></b>	

\* Pricing based on cost of refurbished thermal imaging camera to be used for energy audits. This is a one-time cost for the program.

\*\* Miscellaneous office supplies purchased for program administration, rebate submission forms, flyers and handouts

Delta Natural Gas Company, Inc.  
CEP  
Rebate Budget

	(1)	(2)	(1) x (2)
<u>A. High Efficiency Heating Savings</u>	<u>Program</u>	<u>Rebate</u>	
	<u>Participants</u>	<u>Amount</u>	<u>Total</u>
1. High Efficiency Forced Air Furnaces	160	\$ 400	\$ 64,000
2. High Efficiency Dual Fuel Units	20	300	6,000
3. High Efficiency Gas Space Heating	20	100	2,000
4. High Efficiency Gas Logs/Fireplaces	340	100	34,000
<u>B. High Efficiency Water Heating Savings</u>			
1. High Efficiency Holding Tank Models	63	200	12,600
2. High Efficiency Power Vent Models	6	250	1,500
3. High Efficiency On-Demand Models	1	300	300
			<u>\$ 120,400</u>

(1) Estimated participation in program

(2) Rebate amount, per CEP

Delta Natural Gas Company, Inc.  
CEP  
Energy Audit Budget

Energy Audit Supplies

	Unit Price	Qty	Extended Price
Switch Gasket	\$ 1.97	2.0	\$ 3.94
Outlet gaskets	1.97	3.0	5.91
Foam weather stripping	4.98	0.5	2.49
Fingertip rubber weather stripping	5.47	0.5	2.74
Window and door caulk	4.97	1.0	4.97
Brochure, supply bag	0.85	1.0	0.85
			\$ 20.90
		Rounded	\$ 20.00
		# of audits	46
		<b>Total energy audit expense</b>	<b>\$ 920.00</b>

The above items will be provided to each energy audit participant give them the tools necessary to begin taking steps towards conserving energy.

Delta Natural Gas Company, Inc.  
CEP  
Advertising Budget

Advertising

Media:

Newspaper\*

Advertising space			
publications		15	
# of ad runs		3	
ads		<u>45</u>	
average ad price	\$	375	
			<u>16,875</u>

Website

External costs for design and maintenance related to CEP content

hours		15	
rate per hour	\$	<u>150</u>	
website cost			<u>2,250</u>

Billing Inserts

residential bills		30,000	
quarterly insert		4	
total inserts		120,000	
price, per insert	\$	<u>0.05</u>	
total billing inserts			<u>6,240</u>

**Total Program Advertising** \$ 25,365

Rounded \$ 25,000

\* The on-going program budget accounts for a decline in the usage of newspaper advertising related to the energy audits, as the program becomes more established through customer referrals.

Delta Natural Gas Company, Inc.  
CEP  
Labor Budget

Labor Costs	Hours	Hourly Rate	Labor Cost
(1) Energy Audit	69.0	\$ 20.00	\$ 1,380.00
(2) DSM Inspection	213.5	20.00	4,270.00
(3) Program Administration	52.0	20.00	1,040.00
(4) Accounting	35.0	15.00	525.00
			\$ 7,215.00
Taxes and Benefits @ 12/31/06 rate		38.3%	\$ 2,763.35
<b>Total labor cost</b>			<b>\$ 9,978.35</b>

Rounded \$ 10,000.00

(1) Hours calculated based on the following:

Hours per audit	1.5
Budgeted # of audits	46
	<u>69</u>

(2) DSM Inspection (rebate submission review and compliance)

Budgeted rebates	610
Hours to review rebate submission	0.35
	<u>213.5</u>

(3) Represents estimated administrative time for record keeping and reporting

(4) Accounting time required to prepare CEP filing and adjust billing rates



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27. Refer to the Wesolosky Testimony, pages 11 through 15.
- a. Does the CRS mechanism provide for any consideration of the appropriate rate of return on equity as part of each annual review? Explain why or why not.
  - b. Does the CRS provide for consideration of the reasonableness of the costs and expenses incurred during the Evaluation Period? Explain why or why not.
  - c. Does the CRS provide for updating the cost of debt as part of each annual review? Explain why or why not.
  - d. How did Delta determine that a 45-day period from initial filing of the annual CRS review to the issuance of a Commission Order by October 31 was a reasonable time for staff and the AG to complete their review and for the Commission to render its decision?
  - e. Will Delta file any testimony or narrative discussion relative to its operations and earnings as part of the annual review of the CRS? Explain why or why not.
  - f. What does Delta anticipate its costs will be to file and process an annual CRS case? Provide all assumptions and supporting workpapers.

**RESPONSE:**

- a. No. The CRS does not provide for any consideration of the appropriate rate of return on equity as part of the annual review. The purpose of the CRS is to eliminate the need for frequent rate cases and the costs associated with them. The CRS is not intended to replace the need for a general rate case which is the appropriate forum to debate rate design and theory including but not limited to return on equity, depreciation rates, etc. The CRS is a mechanism designed to only to allow Delta to earn the return as allowed by the Commission in its most recent general rate case.
- b. Yes, to ensure the Commission and the AG can adequately review the CRS adjustment we would envision the review process being a dynamic risk based process where the analysis is focused on the changes in income and expense levels year over year with pre-established materiality criteria to assist in focusing the review efforts.



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- c. Yes, the CRS would update the cost of debt on an annual basis. Since the cost of debt in a given year is known and measurable, the CRS would be updated for changes in the cost of debt.
- d. The CRS is not intended to be litigious, but merely annually filed financial schedules which contain a complete set of data to support the filing. The forty-five day window was derived to allow enough time for analysis and review by the Commission and the AG, but to also promote efficiency in the review process to minimize the cost to our customers. As noted above, the CRS will not propose changes to rate design or update studies, but to ensure Delta can earn the return it has been granted in the most recent rate case.

The time necessary to review the filing should be minimized by agreeing in advance upon filing requirements which will allow the Commission and the AG to perform a risk based analysis of the proposed adjustment. For example, at the conclusion of this current case the Commission and the AG will have extensively reviewed and evaluated our test year and as a result of the data requests historical financial information dating back to our last general rate case. Therefore, the need for the Commission and AG to analyze historical data should be limited. A risk based approach would have the Commission and the AG performing a review and analysis to understand the material changes in income and expense levels in the current year to draw a conclusion as to the reasonableness of the CRS adjustment.

Prior to the first CRS filing, we anticipate working with the Commission and the Office of the Attorney General to develop a meaningful set of filing requirements to minimize the need for supplemental information. However, we would expect the Commission and AG to have some follow up questions, which could be handled through two rounds of data request. The following details the proposed time table for the review:

- Day 1 – Delta submits CRS filing
- Day 7 – First round of data requests
- Day 17 - Responses to data requests
- Day 24 – Second data request
- Day 34 – Responses to second data request
- Day 45 – Order issues by the Kentucky Public Service Commission

In the event the Commission is unable to render an order by the 45<sup>th</sup> day, the rates would go into effect on the 46<sup>th</sup> day subject to refund.

**DELTA NATURAL GAS COMPANY, INC.**

**CASE NO. 2007-00089**

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**DATED 6/07/07**

- e. No testimony will be submitted with the CRS. The CRS is merely an annual filing of schedules to support the adjustment under the rate mechanism. The CRS is not intended to be litigious in nature, as to minimize the cost to our customers. A statement will be filed with the CRS which affirms that the filed schedules are in compliance with the provisions of the mechanism. As the Commission and the AG review the filing, narrative discussions can be provided to answer questions which arise from the review.
  
- f. Assuming a risk based evaluation procedure can be agreed upon to focus the review efforts, Delta does not foresee incurring any incremental costs other than legal expenses for filing the mechanism and supplies associated with preparing the annual CRS filing. We do not expect these amounts to exceed \$10,000 per year.

Sponsoring Witness:

Matthew D. Wesolosky



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

28. Provide an analysis of the annual change in revenues (increase or decrease) that Delta would have implemented each year since its last rate proceeding if it had been operating under the proposed CRS mechanism. Include all workpapers, calculations, and assumptions.

RESPONSE:

See attached.

Sponsoring Witness:

Matthew D. Wesolosky

**KYPSC DR 2-28**

**Estimated CRS Adjustments Based on Case 2004-0067**

	<u>Schedule</u>
CRS Adjustment	1
Return Based on Case 2004-00067	2
Regulated Income Statement	2-1
CRS Tax Adjustment	3
Weighted Average Cost of Capital	4
Rate Base	5
Average Working Capital Balances	5-1

Note:

This analysis does not represent a complete set of schedules which would represent the filing requirements for the CRS. This analysis is an estimate of what the CRS would have been on a historic basis.

Item 28;  
Schedule 1 - CRS Adjustment

	<u>Schedule</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>
Rate base	5	110,112,819	115,453,016	117,818,389
Weighted cost of capital	4	7.858%	7.227%	8.033%
Allowed return		<u>8,652,665</u>	<u>8,343,789</u>	<u>9,464,351</u>
Operating income, before adjustments	2	6,393,183	7,480,662	7,018,057
Adjustments, net of tax	2	89,033	518,050	80,813
Earned return		<u>6,482,216</u>	<u>7,998,712</u>	<u>7,098,870</u>
Allowed return, per above		<u>8,652,665</u>	<u>8,343,789</u>	<u>9,464,351</u>
Revenue deficiency (sufficiency)		<u>2,170,449</u>	<u>345,078</u>	<u>2,365,481</u>
CRS tax adjustment, for gross-up	3	<u>1,380,974</u>	<u>89,761</u>	<u>1,399,074</u>
CRS adjustment		<u>3,551,423</u>	<u>434,838</u>	<u>3,764,555</u>

Item 28;  
Schedule 2 - Return Based on Case 2004-00067

	(1)	(1)	(1)	(10)
	Per Rate Order	12/31/04	12/31/05	12/31/06
	12/31/03			
Operating revenues				
Per books	(52,085,353)	(53,904,811)	(59,996,169)	(67,390,961)
Adjustments				
Temperature adjustment	(2) (115,746)	-	-	-
Customer growth	(2) (132,811)	-	-	-
GCR rate adjustment	(2) (6,227,724)	-	-	-
Unknown to balance to order	(6) (6,089)	-	-	-
Overall revenue deficiency	(2,755,576)	-	-	-
Total adjustments	(9,237,946)	-	-	-
Operating revenues allowed	(61,323,299)	(53,904,811)	(59,996,169)	(67,390,961)
Purchased gas				
Per books	27,846,731	29,587,211	33,029,799	41,730,337
Adjustment to current GCR rate	(2) 6,227,724	-	-	-
Total purchased gas allowed	34,074,455	29,587,211	33,029,799	41,730,337
O&M Expenses				
Per books	10,548,848	10,752,734	12,039,897	11,502,347
Adjustments				
Customer growth	(2) 17,212	-	-	-
Bonus	(8) (317,865)	-	(666,600)	-
Payroll	(2) 133,167	-	-	-
401k cutoff error	(6) 18,465	-	-	-
Pension expense	(2) 58,526	-	-	-
Consultant	(6) (4,900)	-	-	-
Rate case expense	(2) 73,256	-	-	-
Advertising 1.913	(7) (2,204)	(1,990)	(4,362)	(2,264)
Lobbying expenses 1.930.12	(7) (783)	(29,271)	(15,969)	(23,281)
"Extra" lobbying expenses	(5) (16,385)	(16,385)	(16,385)	(16,385)
Lobbying benefits and taxes	(5) (1,289)	(1,289)	(1,289)	(1,289)
Public & Community Relations 1.930.10	(7) (25,645)	(20,872)	(51,431)	(22,664)
Public & Community Relations in M&E	(7) (1,246)	(1,246)	(1,246)	(1,246)
Marketing 1.930.04	(7) (15,239)	(6,666)	(6,299)	(3,973)
Conservation 1.930.11	(7) (44,200)	(41,850)	(25,485)	(32,821)
Directors fees and expenses	(4) (68,447)	(686)	(686)	(686)
Sarbanes Oxley expenses	(6) (51,711)	-	-	-
Computer expenses	(6) (42,404)	-	-	-
AGA membership dues (2%)	(5) (546)	(546)	(546)	(546)
Cust & public info ("promotional items")	(5) (3,432)	(3,432)	(3,432)	(3,432)
Employee gifts, awards	(5) (20,301)	(20,301)	(20,301)	(20,301)
Unknown to balance to order	(6) (9)	-	-	-
Total adjustments	(315,980)	(144,534)	(814,031)	(128,888)
O&M expenses allowed	10,232,868	10,608,200	11,225,866	11,373,459
Depreciation				
Per books	4,190,504	4,349,494	3,988,963	4,234,739
Adjustments	(2) (296,967)	-	-	-
Depreciation expense allowed	3,893,537	4,349,494	3,988,963	4,234,739
Other taxes				
Per books	1,521,231	1,610,589	1,675,148	1,767,481
Payroll tax adjustment	(9) (8,921)	-	(31,075)	-
Other taxes allowed	1,512,310	1,610,589	1,644,073	1,767,481
Income taxes				
Per books (net of unbilled removal)	1,291,200	1,211,600	1,781,700	1,138,000
Adjustments				
Resulting from other adjustments	(3) 427,428	55,501	327,056	48,075
Remove tax effect of unbilled	-	-	-	-
Resulting from overall revenue deficiency	1,089,979	-	-	-
Total adjustments	1,517,407	55,501	327,056	48,075
Income taxes allowed	2,808,607	1,267,101	2,108,756	1,186,075
Operating income				
Per books	(6,686,839)	(6,393,183)	(7,480,662)	(7,018,057)
Adjustments	(2,114,683)	(89,033)	(518,050)	(80,813)
CRS Adjustment, net of tax	-	(2,170,449)	(345,078)	(2,365,481)
Operating income allowed	(8,801,522)	(8,652,665)	(8,343,789)	(9,464,351)
Interest expense				
Per books	4,562,697	4,425,851	4,635,349	4,967,706
Adjustments	(2) 18,102	-	-	-
Interest expense allowed	4,580,799	4,425,851	4,635,349	4,967,706
Net income				
Per books	(2,124,142)	(1,967,332)	(2,845,313)	(2,050,351)
Adjustments	(2,096,581)	(89,033)	(518,050)	(80,813)
CRS Adjustment, net of tax	-	(2,170,449)	(345,078)	(2,365,481)
Net income allowed	(4,220,723)	(4,226,814)	(3,708,440)	(4,496,645)

Notes:

- (1) Represents actual amounts per Delta's books reconciled to the rate order in Case 2004-00067. This has been provided as a frame of reference for the adjustments made to the subsequent years in this analysis
- (2) In a rate case, the premise for a historic test year is to take the actual historic results and make adjustments for known and measurable changes so that the test year can be representative of future years. Since the CRS adjusts annually there are no need for proforma adjustments to annualize expenses
- (3) For 2004-2006, represents the sum of all the pre-CRS adjustments, multiplied by Delta's effective tax rate, per the annual report
- (4) The adjustment from case 2004-0067 included the removal of the Director's bonus as well as the Director's Christmas dinner and gifts. Any bonuses paid to the directors have been excluded in the bonus amount above. Please refer to (5) related to the Christmas dinner and gifts
- (5) For any individual expense item excluded from Case 2004-00067 which is not the entire balance in a general ledger account, we have used the amount specifically excluded from the case for illustrative purpose for each subsequent year in this analysis. We have not gone back to analyze the historical periods to determine the level of such expenditures. For the purposes of the CRS, any specifically excluded item from the current case would be tracked on a prospective basis and the actual amount in a given year would be appropriately excluded from the calculation of the CRS adjustment
- (6) Excluded in case 2004-00067 as a non-recurring expense. Therefore, the expense does not exist in subsequent years for adjustment
- (7) Represents an account balance excluded from the determination of rates in Case 2004-00067. The actual account balance has been excluded each subsequent year
- (8) Actual bonuses paid in the respective years by Delta Natural and the related payroll taxes have been excluded
- (9) In 2003 this amount included payroll taxes on the bonus as well as adjustments to annualize payroll. All subsequent years represent only payroll taxes on bonuses paid by Delta Natural, as wage annualization is not required. See (2) above
- (10) As previously noted, the preceding example excludes certain expenses, based on the 2004 rate order. Therefore expenses excluded per the above example could differ from the amounts actually excluded in Delta's derivation of the revenue requirement for case 2007-00089



Item 28;  
Schedule 3 - CRS Tax Adjustment

	Schedule	2004	2005	2006
Return, net of tax	1	8,652,665	8,343,789	9,464,351
Interest deduction	2	4,425,851	4,635,349	4,967,706
Equity portion of return		4,226,814	3,708,440	4,496,645
Application of tax rate (see below)		1,667,267	1,432,200	1,706,927
ITC amortization (a/c 1.420)	2-1	(38,200)	(37,800)	(37,300)
Amortization of regulatory liability (a/c 1.410.01 subtotal)	2-1	(25,525)	(44,950)	(65,800)
Tax expansion factor		1.65139	1.62920	1.61186
Total income tax liability		2,648,075	2,198,517	2,585,149
Income tax expense, per books	2	(1,211,600)	(1,781,700)	(1,138,000)
Income tax effect of pre-CRS adjustments	2	(55,501)	(327,056)	(48,075)
<b>CRS Income tax adjustment</b>		<b>1,380,974</b>	<b>89,761</b>	<b>1,399,074</b>

	2004	2005	2006
Assume pre-tax income of	100	100	100
State income tax rate of	8.25%	7%	<u>6.00%</u>
State income tax	8.25	7.00	6.00
Taxable income for Federal income tax computation	91.75	93.00	94.00
Federal income tax rate	<u>34.00%</u>	<u>34.00%</u>	<u>34.00%</u>
Federal income tax	31.20	31.62	31.96
Total state and federal income tax	39.45	38.62	37.96
Therefore, the composite rate is	<u>39.45%</u>	<u>38.62%</u>	<u>37.96%</u>
Federal	31.20%	31.62%	31.96%
State	8.25%	7.00%	6.00%
Total	<u>39.45%</u>	<u>38.62%</u>	<u>37.96%</u>

**Item 28;**  
**Schedule 4 - Weighted Average Cost of Capital**

<b>Capitalization</b>	<u>12/31/2004</u>	<u>12/31/2005</u>	<u>12/31/2006</u>
<b>Equity</b>			
Per DNG Balance Sheet	(49,055,982)	(51,524,275)	(52,736,947)
Unbilled	1,754,849	1,794,886	1,482,514
Subsidiaries	<u>924,327</u>	<u>770,705</u>	<u>621,393</u>
	(46,376,806) 39.1%	(48,958,684) 36.3%	(50,633,040) 39.7%
 Long Term Debt	 (54,473,000) 45.9%	 (53,841,000) 39.9%	 (59,870,000) 46.9%
 Short Term Debt	 <u>(17,838,295)</u> 15.0%	 <u>(32,034,527)</u> 23.8%	 <u>(17,146,346)</u> 13.4%
	 <u>(118,688,101)</u>	 <u>(134,834,211)</u>	 <u>(127,649,386)</u>
 <b>Interest Expense</b>			
Interest on Long-Term Debt	3,882,051	3,793,475	3,926,613
Amortization of Debt Expense	<u>236,183</u>	<u>236,184</u>	<u>348,890</u>
Long-Term Debt Expense	4,118,234	4,029,659	4,275,503
 Short-Term Debt Expense	 337,836	 574,633	 662,148
 <b>Cost Rates</b>			
Equity, - based on rate order for case 2004-00067	10.500%	10.500%	10.500%
Long-Term Debt	7.560%	7.484%	7.141%
Short-Term Debt	1.894%	1.794%	3.862%
 <b>Weighted Average Cost of Capital</b>			
Equity	4.103%	3.813%	4.165%
Long-Term Debt	3.470%	2.988%	3.349%
Short-Term Debt	<u>0.285%</u>	<u>0.426%</u>	<u>0.519%</u>
<b>Total Weighted Average Cost of Capital</b>	<b>7.858%</b>	<b>7.227%</b>	<b>8.033%</b>

**Item 28;  
Schedule 5 - Rate Base**

	<u>12/31/04</u>	<u>12/31/05</u>	<u>12/31/2006</u> <sup>1</sup>
Total Utility Plant In Service per books	169,801,075	176,335,961	182,191,297
Add: Materials & Supplies (13 mo avg)	432,137	573,954	434,879
Prepayments (13 mo avg)	588,276	1,509,076	1,609,440
Less: KPSC prepaid	(40,473)	(45,546)	(47,440)
Gas in Storage (13 mo avg)	8,477,820	9,742,489	9,879,627
Unamortized Debt Exp per books	3,948,887	3,712,703	5,704,177
Cash Working Capital Allowance (1/8 O&M)	1,326,025	1,403,233	1,421,682
Subtotal	<u>14,732,672</u>	<u>16,895,909</u>	<u>19,002,365</u>
Deduct: Accumulated Depreciation per books	(56,018,136)	(59,299,589)	(62,107,377)
Less: Depr. Adjustment	-	-	-
Customer Adv for Construction	(63,769)	(60,815)	(51,708)
Accum Deferred Income Taxes (rec below)	<u>(18,339,023)</u>	<u>(18,418,450)</u>	<u>(21,216,188)</u>
Subtotal	<u>(74,420,928)</u>	<u>(77,778,854)</u>	<u>(83,375,273)</u>
Rate Base	<u>110,112,819</u>	<u>115,453,016</u>	<u>117,818,389</u>

*Financial Statement Caption Reconciliation*

Utility Plant in Service			
Plant in Service	169,866,891	176,401,777	182,615,712
ARO Assets	<u>(65,816)</u>	<u>(65,816)</u>	<u>(424,415)</u>
Utility Plant in Service related to rate base	<u>169,801,075</u>	<u>176,335,961</u>	<u>182,191,297</u>
Accumulated Depreciation			
Accumulated Depreciation	(55,228,133)	(58,481,386)	(61,435,867)
Add: Cost of Removal	(816,887)	(845,675)	(831,878)
Less: A/D on ARO Assets	<u>26,884</u>	<u>27,472</u>	<u>160,368</u>
Accumulated Depreciation related to rate base	<u>(56,018,136)</u>	<u>(59,299,589)</u>	<u>(62,107,377)</u>
Accumulated Deferred Income Taxes			
ADIT related to rate base items	(18,339,023)	(18,418,450)	(21,216,188)
ADIT unrelated to rate base items	<u>(1,150,712)</u>	<u>(1,779,600)</u>	<u>(1,675,900)</u>
	<u>(19,489,735)</u>	<u>(20,198,050)</u>	<u>(22,892,088)</u>
Shown on balance sheet as:			
ADIT, Current	-	(999,700)	(701,000)
ADIT, Long term	<u>(19,489,735)</u>	<u>(19,198,350)</u>	<u>(22,191,088)</u>
	<u>(19,489,735)</u>	<u>(20,198,050)</u>	<u>(22,892,088)</u>

<sup>1</sup> Rate base will not agree to rate base, as requested in Case 2007-00089, as assumptions made in Exhibit 2 impact the rate base amounts reported above.

Item 28  
Schedule 5-1  
Calculation of Average Balances for Rate Base

	200401	200402	200403	200404	200405	200406	200407	200408	200409	200410	200411	200412	Average
Gas in storage, at average cost	8,628,806	9,087,501	9,548,759	1,858,884	4,437,692	7,749,234	10,260,926	13,181,380	13,480,046	13,480,046	13,480,046	11,021,554	8,477,820
Gas in storage, at average cost	9,628,806	10,087,501	10,548,759	1,858,884	4,437,692	7,749,234	10,260,926	13,181,380	13,480,046	13,480,046	13,480,046	11,021,554	
Materials and supplies	384,074	386,519	395,929	367,014	362,768	352,762	345,983	383,480	377,103	447,748	476,043	453,748	
1,184,000 INVENTORY	59,246	710,888	793,312	864,542	855,649	1,045,065	78,177	156,516	248,177	322,123	384,045	475,953	
1,184,000 TRANSP EQUIP OPER & MNT COST	98	98	98	211	221	221							
1,184,000 NON OWNED VEHICLE EXPENSE	487,143	(625,120)	(712,782)	(793,172)	(872,003)	(1,045,286)	(85,817)	(173,503)	(257,774)	(341,800)	(418,517)	(488,505)	
1,184,000 TRANSPORTATION EXPENSE CLEARED	128,275	163,692	194,525	211,095	227,439	245,125	20,912	46,698	65,868	82,788	91,140	98,894	
1,184,000 WORK EQUIPMENT OPER MNT COST	(124,630)	(144,668)	(164,019)	(176,184)	(198,731)	(245,125)	(21,000)	(41,040)	(60,166)	(77,287)	(94,239)	(105,872)	
1,184,000 WORK EQUIPMENT EXPENSE CLEARED	451,043	481,108	507,054	470,506	478,762	352,782	338,254	372,160	373,308	433,563	438,472	434,228	432,137
Materials and Supplies													

	200312	200401	200402	200403	200404	200405	200406	200407	200408	200409	200410	200411	200412
1,185,000 PREPAYMENTS	205,150	133,691	87,718	718,216	717,954	634,899	624,946	827,985	833,396	595,666	461,777	390,524	298,666
1,185,010 PREPAYMENT-INTRASOURCE, INC.	8,775	8,775	13,775	13,775	13,775	13,775	1,475	1,475	1,475	7,900	800	7,900	6,375
1,184,010 A/P - MAR CLEARING	117	117	(219)	(241)	(23)	(69)	(241)	(241)	(3,349)	(3,349)	70	70	(241)
1,184,060 MEDICAL - CLEARING	(2,422)	(2,422)	(2,422)	2									
1,184,100 A/P - CIS CLEARING													
1,185,000 PREPAID UNDELIVERED GAS									171,447	335,119	310,699	224,666	463,121
1,185,090 PREPAID INSURANCE													
1,186,110 LONG TERM CARE - CLEARING													
1,186,020 INA INSURANCE CLEARING													
1,184,070 PROVIDENT INSURANCE CLEARING	211,620	140,024	78,854	731,749	751,465	648,335	620,180	623,219	802,954	885,334	781,047	613,886	762,810
Prepayments													

588,276

	200501	200502	200503	200504	200505	200506	200507	200508	200509	200510	200511	200512
Gas in storage, at average cost	1,184,030	6,093,668	3,969,071	4,503,208	7,122,921	9,193,809	10,128,359	10,770,229	12,026,899	15,178,451	16,592,274	12,277,300
Gas in storage, at average cost	1,184,030	6,093,668	3,969,071	4,503,208	7,122,921	9,193,809	10,128,359	10,770,229	12,026,899	15,178,451	16,592,274	12,277,300
Materials and supplies	1,184,030	381,101	369,773	377,534	534,300	857,768	855,092	815,923	678,138	567,102	512,340	427,529
1,184,030 INVENTORY	453,748	600,995	700,243	752,243	834,028	910,258	924,137	1,052,210	232,054	308,911	366,514	480,768
1,184,030 TRANSP EQUIP OPER & MNT COST	475,863				25	98	87	1,48,698	857	881	1,071	1,110
1,184,030 NON OWNED VEHICLE EXPENSE												
1,184,030 TRANSPORTATION EXPENSE CLEARED	(489,505)	(617,325)	(683,543)	(746,408)	(811,356)	(910,893)	(88,697)	(148,368)	(223,523)	(283,855)	(357,830)	(416,663)
1,184,030 WORK EQUIPMENT OPER & MNT COST	98,894	114,017	122,893	130,791	141,414	150,748	160,020	170,830	182,252	192,441	202,358	212,044
1,184,030 WORK EQUIPMENT EXPENSE CLEARED	(105,872)	(120,369)	(128,694)	(138,609)	(147,996)	(157,747)	(167,903)	(178,367)	(189,177)	(199,951)	(210,251)	(220,368)
Materials and supplies	434,228	358,320	380,512	384,378	550,424	837,786	850,592	801,472	683,272	568,520	526,251	478,579

	200412	200501	200502	200503	200504	200505	200506	200507	200508	200509	200510	200511	200512
1-185.000 PREPAYMENTS													
1-184.910 PREPAYMENT INTRASOURCE INC.	293,655	122,015	102,458	82,987	64,687	46,387	28,088	11,1214	91,846	72,577	53,308	35,399	15,936
1-184.910 AF-IMAX CLEARING	6,375	6,375	6,375	(1,625)	3,375	3,375	1,600	1,600	(600)	(600)	3,200	3,200	2,400
1-184.080 MEDICAL CLEARING	(241)	(241)	(233)	(14,278)	(268)	(203)	(40)	(40)	(13,206)	(34,925)	(37,471)	(10)	(255)
1-184.100 AF-CIS CLEARING				(66)		(85)							
1-185.030 PREPAID UNDELIVERED GAS	463,121	769,358	932,605	1,354,009	846,008	356,872	376,879	143,178	512,977	1,079,481	1,705,975	2,387,795	2,557,578
1-185.010 LONG TERM CASE CLEARING		84,750	17,517	778,180	715,787	614,533	543,060	592,969	514,116	429,834	350,441	284,887	231,714
1-184.020 INA INSURANCE CLEARING		(937)											(79)
1-184.070 PROVIDENT INSURANCE CLEARING													
Prepayments	762,910	981,320	1,058,737	2,203,217	1,620,589	1,022,878	899,608	848,017	1,105,133	1,546,024	2,112,835	2,873,722	2,772,007
													1,509,076

	200512	200601	200602	200603	200604	200605	200606	200607	200608	200609	200610	200611	200612
Gas in storage, at average cost	12,277,340	10,778,308	9,386,598	6,559,200	6,701,388	9,186,001	6,580,338	10,007,427	8,844,461	11,559,214	11,853,085	11,024,246	9,809,344
Gas in storage, at average cost	12,277,340	10,778,308	9,386,598	6,559,200	6,701,388	9,186,001	6,580,338	10,007,427	8,844,461	11,559,214	11,853,085	11,024,246	9,809,344
Materials and supplies	427,559	401,574	389,113	349,010	390,268	437,314	432,223	455,087	435,832	424,418	435,717	428,202	441,372
1.184.030 STORAGE GAS - CANADA MT	480,795	553,277	533,458	393,305	517,684	597,507	666,054	793,343	174,733	249,108	327,333	368,785	494,057
Gas in storage, at average cost	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110
1.184.030 TRANSP EQUIP OPER & MNT COST	(46,953)	(49,577)	(567,645)	(740,370)	(869,143)	(895,822)	(871,089)	(777,711)	(172,159)	(249,272)	(330,364)	(400,873)	(484,474)
1.184.030 NON-OWNED VEHICLE EXPENSE	90,046	56,137	70,953	76,456	84,171	99,197	99,197	6,787	19,257	29,866	44,708	51,221	55,649
1.184.080 WORK EQUIPMENT OPER & MNT COST	(83,258)	(71,733)	(79,657)	(88,789)	(97,082)	(105,384)	(93,188)	(6,139)	(17,911)	(25,721)	(33,782)	(40,447)	(48,439)
1.184.090 WORK EQUIPMENT EXPENSE CLEARED	478,378	445,808	450,045	365,134	374,341	423,501	428,712	455,307	439,750	428,218	443,583	437,171	410,166
Materials and supplies	478,378	445,808	450,045	365,134	374,341	423,501	428,712	455,307	439,750	428,218	443,583	437,171	410,166
													8,879,827
													434,070



	200512	200601	200602	200603	200604	200605	200606	200607	200608	200609	200610	200611	200612
1,165,000 PREPAYMENTS	15,836	51,408	31,842	39,491	28,044	19,596	10,148	16,722	12,198	102,216	91,992	81,667	62,815
1,184,010 PREPAYMENT-INTRASOURCE INC.	2,400	2,400	575	7,575	7,575	2,450	2,450	2,450	2,300	1,275	1,275	800	775
1,184,010 AP - MAR CLEARING	(255)									(300)			
1,184,080 MEDICAL - CLEARING	(34,466)			(22,849)	(15,287)	(7,794)			2,278				
1,184,100 AP - CIS CLEARING		59		59									
1,185,030 PREPAID UNDELIVERED GAS	2,557,578	1,612,445	1,321,453	1,233,363	905,510	1,056,999	636,685	840,005	674,420	332,577	792,371	1,613,571	756,483
1,185,050 PREPAID INSURANCE	231,714	117,828	48,872	823,440	741,800	669,391	566,632	612,174	533,127	449,981	357,034	284,187	212,710
1,184,110 LONG TERM CARE - CLEARING							(74)						
1,184,020 INA INSURANCE CLEARING													
1,184,070 PROVIDENT INSURANCE CLEARING													
Prepayments	2,772,907	1,763,081	1,402,144	2,080,078	1,871,507	1,739,670	1,425,337	1,571,362	1,324,322	885,787	1,252,671	1,980,235	1,032,803
													1,609,440

Income Statement History Multiple Years

			2004	2005	2006		
100	Operating Revenues	10	Residential	1.480.010 GS RATE SALES RESIDENTIAL	(27,831,555)	(30,866,875)	(34,155,499)
				1.480.050 UNMETERED GAS LIGHT REVENUE	(14,010)	(5,673)	(9,737)
				<i>Residential</i>	(27,845,565)	(30,872,548)	(34,165,237)
		20	Commercial	1.480.020 GS RATE SALES OTHER COMMERCIAL	(9,751,830)	(10,932,196)	(13,259,071)
				1.480.040 GS RATE SALES SMALL COMMERCIAL	(8,237,297)	(8,846,859)	(10,166,003)
				<i>Commercial</i>	(17,989,127)	(19,779,055)	(23,425,074)
		30	Industrial	1.480.030 GS RATE SALES INDUSTRIAL	(1,228,899)	(1,485,026)	(1,721,229)
				<i>Industrial</i>	(1,228,899)	(1,485,026)	(1,721,229)
		35	Weather Normalization Revenue	1.480.060 WNA RESIDENTIAL	(97,733)	(261,649)	(371,842)
				1.480.070 WNA SMALL NON-RESIDENTIAL	(18,459)	(66,922)	(109,890)
				<i>Weather Normalization Revenue</i>	(116,192)	(328,571)	(481,733)
		40	Commercial	1.481.020 INTERRUPTIBLE RATE COMMERCIAL	(27,429)	(25,388)	(39,289)
				<i>Commercial</i>	(27,429)	(25,388)	(39,289)
		50	Industrial	1.481.030 INTERRUPTIBLE RATE INDUSTRIAL	(448,559)	(455,431)	(484,019)
				<i>Industrial</i>	(448,559)	(455,431)	(484,019)
		60	Miscellaneous Operating Revenue	1.488.010 COLLECTION REVENUE	(109,440)	(119,865)	(137,310)
				1.488.020 RECONNECT REVENUE	(80,232)	(106,272)	(113,856)
				1.488.030 METER TEST REVENUE	(32)	(12)	(40)
				1.488.040 BAD CHECK REVENUE	(9,930)	(9,370)	(10,095)
				<i>Miscellaneous Operating Revenue</i>	(199,634)	(235,519)	(261,301)
		80	Off System Transportation Revenue	1.489.020 OFF SYSTEM TRANSP REVENUE	(1,456,657)	(1,709,109)	(1,797,703)
				1.489.021 OFF SYSTEM TRANSP REVENUE - DELGASCO	(646,363)	(673,821)	(687,244)
				<i>Off System Transportation Revenue</i>	(2,103,020)	(2,382,931)	(2,484,948)

### Income Statement History Multiple Years

			2004	2005	2006
100 Operating Revenues	100 Operating Revenues	100 On System Transportation Revenue	(1,346,334)	(1,610,509)	(1,530,909)
		1.489.040 ON-SYSTEM TRANSP REVENUE			
		1.489.041 ON-SYSTEM TRANSP DR	(2,600,052)	(2,821,192)	(2,797,224)
		<i>On-System Transportation Revenue</i>	(3,946,386)	(4,431,701)	(4,328,133)
			(53,904,811)	(59,996,169)	(67,390,961)
			(53,904,811)	(59,996,169)	(67,390,961)
200 Operating Expenses	200 Purchased gas	110 Purchased Gas	29,587,211	33,029,799	41,730,337
		1.803.000 PURCHASED GAS -- OUTSIDE			
		1.803.100 PURCHASED GAS -- I/C	0		
		<i>Purchased Gas</i>	29,587,211	33,029,799	41,730,337
			29,587,211	33,029,799	41,730,337
300 Operations and maintenance	120 Labor	1.753.010 WELLS & GATHERING PAYROLL	16,373	17,334	8,355
		1.754.010 COMPRESSOR STATION PAYROLL	49,037	51,154	54,680
		1.816.010 CM WELLS EXPENSES -- PAYROLL	45,846	54,446	61,280
		1.818.010 CM COMPRESSOR STATION EXPENSES -- PAYROLL	19,581	18,224	21,113
		1.900.010 TRANS & DIST. PAYROLL	2,442,796	2,436,349	2,560,526
		1.903.010 CASHING PAYROLL	372,665	391,234	404,578
		1.920.010 ADMINISTRATIVE PAYROLL	2,295,040	2,355,694	2,482,184
		1.926.010 TIME OFF PAYROLL	500,261	1,094,355	1,036,705
		<i>Labor</i>	5,741,598	6,418,788	6,629,421
			719,013	549,637	675,613
		1.900.020 OPR TRANSPORTATION EXPENSES			
		1.920.020 ADM TRANSPORTATION EXPENSES	94,050	76,200	94,100
		<i>Transportation</i>	813,063	625,837	769,713
			46,198	51,362	58,165
		1.871.000 TELEMETRY COSTS			
		1.880.010 OPERATIONS OFFICE TELEPHONE	102,589	98,767	98,383

Income Statement History Multiple Years

		2004	2005	2006
200	Operating Expenses			
140	Operations and maintenance			
	1.880.020 OPERATIONS: OFFICE UTILITIES	52,170	57,013	59,497
	1.880.030 OPERATIONS: OFFICE MISC.	90,768	65,725	107,926
	1.880.040 FEES TRAINING SCHOOLS	36,458	35,354	30,008
	1.880.050 UNIFORMS	32,015	30,988	33,589
	1.880.060 WELDING SUPPLIES	11,103	13,640	20,150
	1.881.020 RENT LAND & LAND RIGHTS	16,739	16,984	17,394
	1.821.020 CM PURIFICATION OF NATURAL GAS - MISC		30,092	103,330
	<i>General Operations</i>	388,042	399,924	528,442
150	Customer Billing			
	1.903.020 CUSTOMER COLLECTIONS & RECORDS	230,519	231,133	223,782
	<i>Customer Billing</i>	230,519	231,133	223,782
160	Uncollectible Accounts			
	1.904.000 UNCOLLECTIBLE ACCOUNTS	529,301	601,623	484,710
	<i>Uncollectible Accounts</i>	529,301	601,623	484,710
170	Administrative			
	1.921.010 ADM TELEPHONE	150,960	142,713	141,689
	1.921.030 BOOKS & SUBSCRIPTIONS	24,431	27,127	22,731
	1.921.040 COMPANY FORMS	24,481	24,543	29,263
	1.921.050 SMALL SUPPLY ITEMS	54,827	57,416	62,149
	1.921.060 MISCELLANEOUS OTHER ITEMS	58,507	130,062	151,008
	1.921.070 EMPLOYEE MEMBERSHIPS	3,987	3,512	3,708
	1.921.080 SAFETY LITERATURE & EDUCATION	15,767	13,259	18,782
	1.921.090 ENGR & DRAFTING SUPPLIES	5,471	6,025	6,260
	1.921.100 ADM UTILITIES	41,128	44,156	45,850
	1.921.110 INVENTORY - DIFFERENCE	905	2,869	(1,074)
	1.921.210 TRAVEL ETC CO BUS PRES & CEO	9,296	6,801	11,421

## Income Statement History Multiple Years

			2004	2005	2006
200	Operating Expenses	300			
		170			
	Operations and maintenance				
			1,921.220	TRAVEL ETC CO BUS OFFICERS	7,971
			1,921.230	TRAVEL ETC CO BUS OPER & CONST	9,732
			1,921.240	TRAVEL ETC CO BUS ADM & CUST SER	7,024
			1,921.260	TRAVEL ETC CO BUS FINANCE	4,201
			1,921.290	CO. BUS. MEALS & ENTERTAINMENT	33,316
			1,921.300	COMPUTER EQUIPMENT OPERATIONS	14,033
			1,921.270	TRAVEL ETC CO BUS TREASURY	0
				<i>Administrative</i>	
			466,038		579,827
		180			
	Outside Services		1,923.010	OUTSIDE SERVICES LEGAL	39,135
			1,923.020	OUTSIDE SERVICES ACCOUNTING	260,658
			1,923.030	OUTSIDE SERVICES JANITORIAL	58,215
			1,923.040	OUTSIDE SERVICES OTHER	68,325
			1,923.050	OUTSIDE SERVICES COMPUTERS	123,086
				<i>Outside Services</i>	
			549,419		765,795
		190			
	Insurance		1,924.000	INSURANCE	652,785
				<i>Insurance</i>	
			652,785		754,608
		200			
	Employee Benefits		1,926.020	PENSION	652,264
			1,926.030	EMPLOYEE 401K PLAN	211,950
			1,926.040	MEDICAL COVERAGE	1,062,034
			1,926.050	SALARY CONTINUATION COVERAGE	114,364
			1,926.060	EMPLOYEE STOCK PLAN	27,813
			1,926.070	EMPLOYEE EDUCATION	2,641
			1,926.080	EMPLOYEE RECREATION & SOCIAL	10,289
			1,926.100	SUPPLEMENTAL RETIREMENT PLAN	60,000
					61,782
					72,258

Income Statement History Multiple Years

			2004	2005	2006
200	Operating Expenses	Operations and maintenance	2,141,355	2,418,522	2,145,052
210	Employee Benefits	Employee Benefits			
	General	1.913.000 ADVERTISING	1,990	4,362	2,264
	Administration	1.928.000 REGULATORY COMMISSION EXPENSE	155,154	159,545	163,359
		1.930.010 DIRECTOR FEES & EXPENSES	228,946	304,326	204,464
		1.930.020 COMPANY MEMBERSHIPS	21,254	50,768	49,470
		1.930.030 FEES CONVENTIONS & MEETINGS	9,810	8,047	6,125
		1.930.040 MARKETING	6,666	6,299	3,973
		1.930.050 COMPANY RELATIONS	12,601	20,809	15,945
		1.930.060 TRUSTEE, REGISTRAR, AGENT FEES	75,597	63,648	69,450
		1.930.080 STOCKHOLDER REPORTS	74,574	77,393	74,536
		1.930.090 CUSTOMER & PUBLIC INFORMATION	28,873	40,797	30,493
		1.930.100 PUBLIC & COMMUNITY RELATIONS	20,872	51,431	52,664
		1.930.110 CONSERVATION PROGRAM	41,850	25,485	32,821
		1.930.120 LOBBYING EXPENDITURES	29,271	15,969	22,281
		1.930.130 MISC NON-TAX DEDUCTIBLE	338	115	375
		<i>General Administration</i>	707,796	828,992	728,220
220	Expenses Transferred	1.922.000 EXP. TRANSFERRED - CAPITAL	(2,394,967)	(2,281,038)	(2,349,858)
		1.922.100 EXP. TRANSFERRED I/C	(85,496)	(227,485)	(686,711)
		<i>Expenses Transferred</i>	(2,480,463)	(2,508,523)	(3,036,569)
230	Other	1.753.020 WELLS & GATHERING MISC	411	644	500
		1.754.020 COMPRESSOR STATION MISC.	52,670	70,055	67,208
		1.816.020 CM WELLS EXPENSES - MISC	1,367	3,027	366
		1.818.020 CM COMPRESSOR STATION EXPENSES - MISC	14,901	19,549	24,964

## Income Statement History Multiple Years

			2004	2005	2006
200	Operating Expenses	300			
	Operations and maintenance	230			
	Other				
	1.821.000 CM PURIFICATION OF NATURAL GAS		65,603	37,247	
	1.824.020 CM OTHER UNDERGROUND STORAGE EXPENSES - MISC		1,366	580	1,808
	1.825.000 CM STORAGE WELL ROYALTIES/RENTS		56,004	56,249	56,371
	1.856.000 RIGHT OF WAY CLEARING		58,962	81,164	66,285
	1.900.030 SMALL TOOLS & WORK EQUIPMENT		88,912	71,379	108,395
	<i>Other</i>		340,197	339,894	325,897
	240 Labor				
	1.764.010 MINT WELLS & GATHERING PAYROLL		159	1,051	316
	1.765.010 MINT COMPRESSOR STATION PAYROLL		6,789	13,274	12,318
	1.832.010 CM MAINT OF RESERVOIRS AND WELLS - PAYROLL		1,019	1,819	907
	1.834.010 CM MAINT OF COMPRESSOR STATION EQUIP - PAYROLL		2,508	761	9,527
	1.835.010 CM MAINT OF MEAS & REG STATE EQUIP - PAYROLL		411	263	483
	1.887.010 MINT TRANS & DIST MAINS PAYROLL		109,055	50,688	86,672
	1.893.010 MINT OF METERS & REG PAYROLL		14,437	15,125	16,313
	1.894.010 MINT OF OTHER EQUIPMENT PAYROLL		12,078	8,208	9,805
	<i>Labor</i>		146,456	91,188	136,342
	250 Transportation				
	1.898.010 MINT - TRANSP EQUIP EXPENSE - PAYROLL		44,275	20,757	36,961
	1.898.020 MINT - POWER OPER EQUIP EXPENSE - PAYROLL		30,372	6,421	8,955
	<i>Transportation</i>		74,648	27,178	45,916
	260 Mains				
	1.887.020 MINT TRANS & DIST MAINS OTHER		79,857	62,737	63,707
	<i>Mains</i>		79,857	62,737	63,707

## Income Statement History Multiple Years

			2004	2005	2006
200 Operating Expenses	300 Operations and maintenance	270 Meter & Regulators	35,643	62,428	42,994
		1.893.020 MINT OF METERS & REG. OTHER			
		<i>Meter &amp; Regulators</i>	35,643	62,428	42,994
	280 Other	1.764.020 MINT WELLS & GATHERING OTHER	1,293	11	
		1.765.020 MINT COMPRESSOR STATION OTHER	20,957	18,691	21,183
		1.831.020 CM MAINTENANCE STRUCTURES & IMPROVEMENTS - MISC	3,555	10,318	2,649
		1.832.020 CM MAINTENANCE OF RESERVOIRS AND WELLS - MISC	32,898	47,022	43,432
		1.833.020 CM MAINTENANCE OF LINES - MISC	1,711		
		1.834.020 CM MAINTENANCE OF COMPRESSOR STAT EQUIP - MISC	7,017	9,341	26,302
		1.835.020 CM MAINTENANCE OF MEAS & REG STAT EQUIP - MISC	1,440	1,964	1,735
		1.837.020 CM MAINTENANCE OF OTHER EQUIPMENT - MISC	615	6,635	2,303
		1.886.000 MINT STRUCTURES TRANS & DIST.	4	101	
		1.889.000 MINT REG STATION TRANS & DIST.	6,730	4,332	7,505
		1.894.020 MINT OF OTHER EQUIPMENT OTHER	94,280	78,746	102,281
		1.932.010 MINT COMMUNICATION EQUIPMENT	30,745	38,124	38,523
		1.932.020 MINT OFFICE EQUIPMENT	28,207	30,465	30,419
		1.932.030 MINT GENERAL STRUCTURES	47,928	44,989	41,636
		1.932.050 MAINTENANCE COMPUTER EQUIPMENT	59,100	77,008	72,817
		<i>Other</i>	336,481	367,747	390,785
		<i>Operations and maintenance</i>	10,752,734	12,039,897	11,502,347
400 Depreciation and depletion	290 Depreciation Expense	1.403.000 DEPRECIATION EXPENSE	4,356,287	3,997,035	4,246,739



## Income Statement History Multiple Years

		2004	2005	2006
200 Operating Expenses	400 Depreciation and depletion	743	588	0
	1.403.100 DEPRECIATION EXPENSE FOR ASSET RETIREMENT COST			
	1.406.000 AMORT OF GAS PLANT ACCO ADJ-TRANEX	(58,800)	(58,800)	(58,800)
	1.406.010 AMORT OF GAS PLANT ACCO ADJ-MIT OLEVET	46,800	46,800	46,800
	1.411.100 ACCRETION EXPENSE	4,464	3,340	0
	<i>Depreciation Expense</i>	4,349,494	3,988,963	4,234,739
	<i>Depreciation and depletion</i>	4,349,494	3,988,963	4,234,739
500 Taxes other than income taxes	300 Property Taxes	4,630	5,414	5,432
	1.408.010 LICENSE & PRIVILEGE FEES			
	1.408.020 PROPERTY TAXES	1,106,755	1,133,426	1,221,140
	<i>Property Taxes</i>	1,111,386	1,138,840	1,226,572
310 Payroll Taxes	1.408.030 PAYROLL TAXES	499,203	536,308	540,909
	<i>Payroll Taxes</i>	499,203	536,308	540,909
	<i>Taxes other than income taxes</i>	1,610,589	1,675,148	1,767,481
	<i>Operating Expenses</i>	46,300,028	50,733,807	59,234,904
400 Interest Charges	390 Interest On Long Term Debt	3,822,051	3,793,475	3,926,613
	1.427.000 INTEREST ON LONG TERM DEBT			
	<i>Interest On Long Term Debt</i>	3,822,051	3,793,475	3,926,613
	400 Interest On Short Term Debt	335,536	586,333	718,348
	1.431.020 INTEREST ON SHORT-TERM DEBT			
	1.431.021 SUBSIDIARY INTEREST	2,300	(11,700)	(56,200)
	<i>Interest On Short Term Debt</i>	337,836	574,633	662,148
	410 Other Interest	29,780	31,056	30,055
	1.431.010 INTEREST ON CUSTOMER DEPOSITS			
	<i>Other Interest</i>	29,780	31,056	30,055
	420 Amortization Of Debt Expense	236,183	236,184	348,890
	1.428.000 AMORT OF DEBT EXPENSES			
	<i>Amortization Of Debt Expense</i>	236,183	236,184	348,890

Income Statement History Multiple Years

		2004	2005	2006
400 Interest Charges	Interest charges	4,425,851	4,635,349	4,967,706
<i>Interest Charges</i>				
500 Income Taxes	800 Income taxes	4,425,851	4,635,349	4,967,706
	320 Current Federal	(609,081)	31,960	(1,391,650)
	1.409:070 ESTIMATED INTERIM INCOME TAXES	1	0	0
	<i>Current Federal</i>	(609,080)	31,960	(1,391,650)
	330 Current State	325,305	68,540	(273,813)
	<i>Current State</i>	325,305	68,540	(273,813)
	340 Deferred Federal & State	2,648,400	1,789,050	2,724,863
	1.410:000 DEFERRED INCOME TAXES			
	1.410:010 AMORT OF REGULATORY LIABILITY	(25,525)	(44,950)	(65,800)
	<i>Deferred Federal &amp; State</i>	2,622,875	1,744,100	2,659,063
	350 Investment Tax Credit-Net	(38,200)	(37,800)	(37,300)
	1.420:000 INVESTMENT TAX CREDIT-NET			
	<i>Investment Tax Credit-Net</i>	(38,200)	(37,800)	(37,300)
	<i>Income taxes</i>	2,300,900	1,806,800	956,300
	<i>Income Taxes</i>	2,300,900	1,806,800	956,300
	<i>Net Income</i>	(878,032)	(2,820,213)	(2,232,051)
	Remove tax effect of unbilled	(1,089,300)	(25,100)	181,700
	Net Income excluding unbilled	(1,967,332)	(2,845,313)	(2,050,351)



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29. Refer to the Wesolosky Testimony, pages 13 and 14.
- a. Define incremental employee costs.
  - b. Explain how Delta expects the Commission and the AG to account for incremental employee costs.
  - c. Delta states it envisions the filing requirements for the CRS would be determined through a collaborative process between the Commission, the AG, and Delta.
    - (1) Assuming the Commission approved the CRS as proposed, when would Delta expect this collaborative process to begin?
    - (2) In the event the participants cannot agree on the filing requirements, what would be the affect on the CRS?

RESPONSE:

- a. Because of the additional time required to review the CRS filing, we realize that additional staffing may be required to allow the Commission and AG to adequately review the filing. This incremental cost would be the actual hours it takes to perform review of Delta's filing multiplied by the hourly rate of the employee(s) reviewing the filing. Recovery of these costs would be limited to the equivalent salary of a full-time staff member. As noted in the response to KYPSC DR 2-4, this would provide the Commission and Office of the Attorney General approximately 2,000 hours to review the filing within the 45 day review period.
- b. We would expect the Commission and AG staff to track their time in conjunction with their normal time keeping process to provide contemporaneous documentation as to how many hours were spent on the review. These hours per employee would then be multiplied by the employee's hourly rate to arrive at the labor cost. The labor cost would be rendered on an invoice to Delta for payment subsequent to the forty-five day review period. Any invoices submitted by the Office of the Attorney General would be approved by the Commission prior to payment by Delta.

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c.

1. Delta would expect the collaborative process to begin within a month subsequent to the issuance of the final Order in this case. However, if there are significant reservations on the part of the Commission and/or the Attorney General related to the filing requirements Delta would be open to a conference with both parties present to expedite the collaborative process.
2. Ultimately it is our goal to work with both parties to develop a list of meaningful filing requirements which would provide the information needed for both parties to analyze the reasonableness of the adjustment under the CRS. However, we are cognizant that neither Delta nor the Attorney General have the authority to set the rates and therefore ultimate decision of what is required to perform a proper analysis resides with the Commission.

Sponsoring Witness:

Matthew D. Wesolosky



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30. Refer to the Wesolosky Testimony, page 14.
- a. Has Delta developed any estimates of the additional cost to the Commission or to the AG for the additional staff they will need in order to process the application within the 45-day time frame? Explain the response.
  - b. If Delta has experienced decreased customer counts and volumes sold during the past 5 years, is there any expectation that the CRS mechanism will ever decrease rates or is the expectation that the rates will routinely increase?
  - c. If rates are increased both in this current case and through the CRS, will the decline in the number of customers and volumes sold continue as customers try to lower their bills through conservation?

RESPONSE:

- a. Delta has not developed any estimates of the additional cost to the Commission or AG. See the response KYPSC DR 2-29.
- b. Due to the number of variables which impact a customer's decision to remain on natural gas service including commodity pricing, weather trends and economic factors we cannot predict with any certainty as to what long-term customer trends will be. However, based on the rate cases we have filed with the Commission in the past ten years we have not seen a reduction in our cost of service over that time period.
- c. Regardless of the approval of the CRS mechanism we expect our customers to continue the trend of conservation to both minimize their bill as well as conserve a natural resource. However, we believe the CRS will not have a negative impact on the number of customers we serve, in fact we believe the CRS will help us retain customers, especially those who are on a fixed income. Given a forward looking period of rising prices, the CRS would inherently increase each year. In this situation we believe that we are better able to retain customers with gradual increases in the base rate under the CRS each year versus an increase of a greater magnitude every three to five years. For example in the current case we are seeking a 9.25% increase in our base rate. Since the last rate case was three years ago this would have averaged an increase of approximately 3% per year, which is on par with inflation, which was 9.42% from 2004 through 2007. The current process for adjusting rates does not contemplate annual increases in the cost of

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doing business, so every 3-5 years we must request an increase of a greater magnitude to catch up with the cost of doing business. Many customers, especially those on a fixed income, have a hard time with large bill increases as they are unplanned. However, if rates increased ratably over the same time as the rising prices, the increases would be gradual and provide the customer more flexibility in budgeting for their utility expenditures.

Sponsoring Witness:

Matthew D. Wesolosky





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31. Refer to the Wesolosky Testimony, page 15. Delta states that the off-system transportation rates would be considered in general rate cases every 5 years.
- a. Does Delta's proposed CRS mechanism allow for general rate cases every 5 years?
  - b. If no, is Delta willing to commit to filing a general rate case every 5 years?
  - c. If no, explain how the Commission can be assured that the off-system transportation rates will be adjusted every 5 years.

**RESPONSE:**

The CRS mechanism states that it is an experimental mechanism and its continuance will be considered in five years. Assuming the continuation of the mechanism, Delta would be willing to commit to a general rate case every five years.

Sponsoring Witness:

Matthew D. Wesolosky



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32. Refer to the Application, the Direct Testimony of Martin J. Blake (“Blake Testimony”), pages 10 through 15.
- a. Provide a table illustrating Delta’s year-end capital structure for the last 12 years.
  - b. Provide an explanation of how the company determines its capital structure and any documentation, including Board minutes demonstrating that the company has purposefully attempted to increase the equity portion of its capital structure over the last 12 years in order to earn a higher return.
  - c. Exhibit MJB-2 lists 15 natural gas distribution companies and their percentage of equity to total capitalization. For each listed company, provide a breakdown of the revenues into regulated and nonregulated revenues, including a distinction between natural gas distribution revenues and all other regulated revenues. Also include any revenues from international investments and whether or not any were involved in merger activity at the time of the analysis.
  - d. Provide an explanation of Delta’s target percent equity.
  - e. If Delta is awarded its recommended return on equity (“ROE”), provide an explanation of what actions it plans to take to increase the equity portion of its capital structure, and how those actions will increase its equity percentage.
  - f. If customer conservation and/or customer loss is a reason for Delta’s inability to earn its allowed rate of return on equity, explain why the proposed rate increase will not exacerbate the problem.
  - g. Is it possible that a failure to adequately control expenses could also be a factor in Delta’s inability to earn its allowed return on equity? Explain the response.

RESPONSE:

- a. See attached Item 32a – schedule prepared by John B. Brown.
- b. Delta has for years tried to gradually increase the equity component of its capital structure. There is no set goal, but the Company has tried to be more in line with the industry averages, or about a 50% equity range. Delta has issued equity over the years, but debt as well, to meet its capital needs. Thus, depending on timing, debt versus equity percentages have varied. Sometimes Delta has been more

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leveraged due to this. Also, when Delta's earnings exceed its dividends paid, its retained earnings increase, thus increasing its common equity component of capital.

- c. I do not have the information that you are requesting. The Edward Jones Quarterly Financial and Common Stock Information Report that I used as a data source in my study did not include this information. However, the fifteen natural gas distribution companies that I used as my panel were classified as "Distribution" in the Edward Jones report which means that at least 90% of their net operating revenues were recovered from regulated natural gas distribution. This would imply that less than 10% of their revenues were received from unregulated activities. There was no information in the Edward Jones report regarding international investments or merger activity.
- d. See response to (b).
- e. See response to (b).
- f. Although it is possible that an increased per unit price of natural gas could lead to further reduced consumption per customer or the loss of customers, that is no reason to deprive Delta of its legal right to recover its prudently incurred expenses and earn a fair rate of return on the investment that it has made to provide service to its customers. Conversely, a lower price might encourage consumption, but additional sales volume does a utility little good if it is selling below cost and is generating low or negative margins. I believe that PG&E's bankruptcy experience in the early 2000's is a good illustration of this point.
- g. A failure to adequately control expenses could result in a utility being unable to earn its allowed rate of return. However, I do not believe that this is the case for Delta. In prior rate cases, the Commission has never indicated that Delta's failure to control expenses is a problem. Furthermore, Delta has under-earned in all of the years immediately following a rate case for the last ten years. The year immediately following a rate case is when the utility should have the highest probability of earning its allowed rate of return. That this has not happened in ten years indicates a more fundamental problem to me, and I have described why I believe that Delta has been under-earning in my testimony.

Sponsoring Witness:

Martin J. Blake

Line No.	Type of Capital	1995		1996		1997		1998		1999	
		Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio
1	Long-Term Debt	26,129	44.2%	40,243	53.7%	39,530	46.3%	54,208	60.0%	52,969	54.5%
2	Short-Term Debt	12,710	21.5%	7,790	10.4%	19,395	22.7%	9,030	10.0%	16,700	17.2%
3	Preferred Preference Stock										
4	Common Equity	20,245	34.3%	26,887	35.9%	26,392	30.9%	27,072	30.0%	27,491	28.3%
5	Total Capitalization	59,084		74,920		85,317		90,310		97,160	

Line No.	Type of Capital	2000		2001		2002		2003		2004	
		Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio
1	Long-Term Debt	51,905	51.2%	50,580	46.7%	49,911	45.2%	54,824	46.7%	54,473	45.9%
2	Short-Term Debt	20,745	20.5%	27,755	25.6%	29,038	26.3%	17,708	15.1%	17,838	15.0%
3	Preferred Preference Stock										
4	Common Equity	28,749	28.4%	30,052	27.7%	31,497	28.5%	44,978	38.3%	46,377	39.1%
5	Total Capitalization	101,399		108,387		110,446		117,510		118,688	

Line No.	Type of Capital	2005		2006	
		Amount	Ratio	Amount	Ratio
1	Long-Term Debt	53,841	39.9%	59,870	46.9%
2	Short-Term Debt	32,034	23.8%	17,146	13.4%
3	Preferred Preference Stock				
4	Common Equity	48,959	36.3%	50,633	39.7%
5	Total Capitalization	134,834		127,649	



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33. Refer to the Blake Testimony, page 15. Dr. Blake states, "Furthermore, these rural customers tend to have a lower annual usage and a larger proportion of temperature sensitive load than urban customers." Provide copies of studies demonstrating the validity of this statement.

**RESPONSE:**

This statement was not based on a study and there is no study that I am aware of that shows this. This statement was based on my observations from working with other natural gas companies that have a more urban customer base compared to Delta. Additionally, this is not a key assumption in supporting my recommendation regarding the return on equity that Delta should be allowed to earn in this proceeding. I was sharing an observation with the Commission to help them understand why Delta may not be like other natural gas companies that the Commission regulates.

Sponsoring Witness:

Martin J. Blake





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34. Refer to the Blake Testimony, pages 17 and 18.
- a. Explain why Delta has a gas cost recovery mechanism and the benefits Delta derives from this mechanism.
  - b. Is Dr. Blake advocating that Delta be allowed to earn a return on the under-recover and deferred gas costs? If so, should Delta also be required to pay interest on over-recoveries?
  - c. Provide a chart illustrating the amount of revenue that would have been generated by Delta if it had been allowed to earn a return on the under-recovered and deferred gas costs and the effect on year-end returns. The chart should illustrate revenues by month since the rates from the last rate case went into effect and should include a list of all assumptions.
  - d. To the extent that internal financing and short-term borrowing were used to finance under-recoveries and deferred gas costs, explain how Delta will not capture these expenses along with other expenses during the test year?

RESPONSE:

- a. The three criteria for determining whether a tracker is appropriate for recovering a cost that are applied by most regulatory commissions are: 1) is the cost significant, 2) is the cost outside of the company's control, and 3) is the cost volatile. For Delta Natural Gas, the cost of natural gas meets all three of these criteria. Thus, the use of a tracker in the form of a gas cost recovery mechanism is appropriate for Delta. Without a tracker to recover natural gas costs, both the size and volatility of natural gas commodity costs could result in serious financial harm to Delta. Through the gas cost recovery mechanism, customers pay for the natural gas commodity exactly what it costs Delta to purchase the natural gas. Both Delta and its customers benefit from the gas cost recovery mechanism.
- b. Although Delta is not requesting to earn a return on under-recovered and deferred gas costs in this proceeding, I believe that earning a return on under-recovered and deferred gas costs would be appropriate and would help to relieve the chronic under-earning that Delta has experienced over the last ten years. If the Commission allows Delta to earn a return on under-recovered and deferred gas costs, it would also be appropriate for Delta to pay interest on over-recoveries.
- c. See attached analysis.

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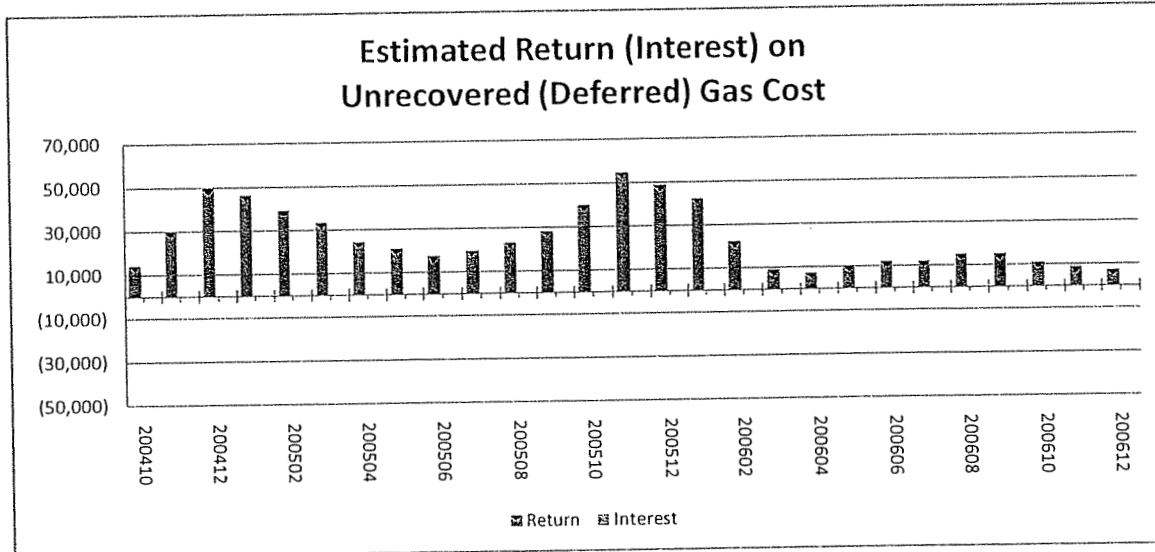
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- d. Delta will recover the interest paid for any external debt used to finance under-recoveries and deferred gas costs that were incurred during the test year, but it will not receive a return for any internal funds used to finance under-recoveries and deferred gas costs. Delta will recover the cost of the gas commodity and any interests payments on short term debt as expense items during the test year, but there is no mechanism for Delta to earn a return on under-recoveries and deferred gas costs and Delta's equity used to finance these under-recoveries and deferred gas costs would not show up as an expense item.

Sponsoring Witness:

Martin J. Blake

The following analysis calculates the return on unrecovered gas costs and the interest on deferred gas costs from any under or over collection, respectively. Both the return and interest are calculated based on the approved capital structure and equity/debt cost rates approved in Delta's last rate case.



Month	(3) Unrecovered (Deferred) Gas Cost	(2) x (3) Calculated	
		(a) Return on Unrecovered	(b) Interest on Deferral
200410	2,206,830	14,560	-
200411	4,536,728	29,932	-
200412	7,490,432	49,420	-
2004 Totals		93,912	-
200501	7,027,093	46,363	-
200502	5,919,721	39,057	-
200503	5,075,104	33,484	-
200504	3,712,258	24,493	-
200505	3,200,996	21,119	-
200506	2,646,868	17,463	-
200507	3,006,493	19,836	-
200508	3,529,306	23,286	-
200509	4,292,143	28,319	-
200510	6,037,403	39,833	-
200511	8,254,829	54,464	-
200512	7,363,944	48,586	-
2005 Totals		396,303	-
200601	6,408,276	42,280	-
200602	3,369,173	22,229	-
200603	1,370,175	9,040	-
200604	1,124,033	7,416	-
200605	1,585,272	10,459	-
200606	1,827,078	12,055	-
200607	1,814,662	11,973	-
200608	2,311,211	15,249	-
200609	2,319,006	15,300	-
200610	1,713,566	11,306	-
200611	1,342,330	8,856	-
200612	1,117,889	7,376	-
2006 Totals		173,539	-

(a) Per the data request, represents the return which would have been earned on the unrecovered gas cost. Unrecovered gas costs result from under collection of gas costs through the GCR mechanism.

(b) Per the data request, represents the calculated return which would have been refunded as a result of deferred gas cost. Deferred gas costs result from over collection of gas costs through the GCR mechanism.

	Capital Structure	Cost of Capital Allowed	WAC
Equity	38%	10.500%	4.019%
Long Term Debt	47%	7.422%	3.463%
Short Term Debt	15%	2.891%	0.436%
			7.917% (1) Annual
			0.660% (2) - Monthly



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35. Refer to the Blake Testimony, pages 32 through 36, regarding the discussion of the proposed CRS Mechanism. Although Alabama does not appear to require a reduction in ROE due to reduced risk, is Dr. Blake aware of any jurisdictions that have made such an adjustment due to reduced risk associated with a CRS mechanism? Explain the response.

RESPONSE:

No, I am not aware of other jurisdictions that have made such adjustments due to reduced risk associated with a CRS mechanism.

Sponsoring Witness:

Martin J. Blake



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36. Refer to the Blake Testimony, page 33. Provide a schedule showing gas usage per customer for the past 10 years.

RESPONSE:

See attached support.

Sponsoring Witness:

John B. Brown



DELTA NATURAL GAS CO., INC.  
 Customer Count and Usage  
 Ten Years Ended December 2006

**CUSTOMERS BILLED IN DECEMBER**

	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Residential	32,511	33,323	33,691	34,100	34,479	34,168	34,456	33,937	32,940	32,637
Small Non-Residential	4,449	4,513	4,545	4,629	4,667	4,536	4,618	4,488	4,346	4,316
Large Non-Residential	868	858	843	872	872	878	865	861	838	828
Interruptible	8	8	9	9	9	8	9	8	8	8
Delta Natural Retail	37,836	38,702	39,088	39,610	40,027	39,590	39,948	39,294	38,132	37,789

**USAGE BILLED CALENDAR YEAR**

	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Residential	1,779,377	2,036,700	2,100,518	2,293,335	2,266,494	2,428,308	2,425,184	2,247,997	2,142,320	2,527,891
Small Non-Residential	544,497	604,106	630,092	697,273	667,590	686,680	653,605	590,359	579,188	698,126
Large Non-Residential	888,907	922,886	940,845	985,231	936,257	982,125	975,842	950,624	932,655	1,124,179
Interruptible	35,216	41,530	47,309	51,349	44,570	105,733	58,988	49,015	48,093	57,969
Delta Natural Retail	3,247,997	3,605,222	3,718,764	4,027,188	3,914,911	4,202,846	4,113,619	3,837,995	3,702,256	4,408,166

**USAGE PER YEAREND CUSTOMERS**

	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Residential	54.7	61.1	62.3	67.3	65.7	71.1	70.4	66.2	65.0	77.5
Small Non-Residential	122.4	133.9	138.6	150.6	143.0	151.4	141.5	131.5	133.3	161.7
Large Non-Residential	1,024.1	1,075.6	1,116.1	1,129.9	1,073.7	1,118.6	1,128.1	1,104.1	1,112.3	1,357.7
Interruptible	4,402.0	5,191.3	5,256.6	5,705.4	4,952.2	13,216.6	6,554.2	6,126.9	6,216.7	7,551.5
Delta Natural Retail	85.8	93.2	95.1	101.7	97.8	106.2	103.0	97.7	97.1	116.7



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37. Refer to the Blake Testimony, page 37. Dr. Blake states that under the proposed CEP, Delta would be recovering lost sales resulting from the rebate program, the home energy audits, and customer awareness.
- a. Explain in detail how the lost sales associated with customer awareness would be determined.
  - b. Page 8 of the Wesolosky Testimony states that lost sales will be determined for the rebate and energy audit components of the proposed CEP only. Explain how Dr. Blake concluded that lost sales would be determined on customer awareness.

RESPONSE:

- a. In my testimony on page 37, I stated that it would be “appropriate for the Commission to allow Delta to recover the cost of implementing these programs, an incentive for pursuing these demand side programs and recovery of lost sales resulting from these programs.” This statement is broader than what Delta actually seeks to recover regarding lost revenues. Delta does not seek to recover lost revenues for customer awareness programs.
- b. Including a lost revenue component for customer awareness programs was a mistake on my part. Delta is not seeking lost revenue recovery for customer awareness programs.

Sponsoring Witness:

Martin J. Blake



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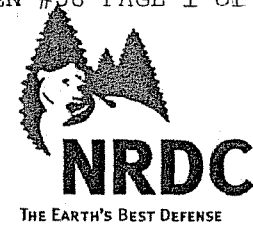
38. Refer to the Blake Testimony, page 38. Provide copies of the American Gas Association and Natural Resources Defense Council's joint statement titled "Energy Efficiency Problem: Regulated Natural Gas Utilities are Penalized for Aggressively Promoting Energy Efficiency," as referenced.

RESPONSE:

The requested document is attached.

Sponsoring Witness:

Martin J. Blake



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## Joint Statement of the American Gas Association and the Natural Resources Defense Council

Submitted to the National Association of Regulatory Utility Commissioners  
July 2004

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The American Gas Association (AGA) and the Natural Resources Defense Council (NRDC) recognize the many benefits of using clean-burning natural gas efficiently to provide high quality energy services in all sectors of the economy. This statement identifies ways to promote both economic and environmental progress by removing barriers to natural gas distribution companies' investments in urgently needed and cost-effective resources and infrastructure.

NRDC and AGA agree on the importance of state Public Utility Commissions' consideration of innovative programs that encourage increased total energy efficiency and conservation in ways that will align the interests of state regulators, natural gas utility company customers, utility shareholders, and other stakeholders. Cost-effective opportunities abound to improve the efficiency of buildings and equipment in ways that promote the interests of both individual customers and entire utility systems, while improving environmental quality. For example, when energy supply and delivery systems are under stress, even relatively modest reductions in use can yield significant additional cost savings for all customers by relieving strong upward pressures on short-term prices.

NRDC and AGA also encourage state Commissions to support gas distribution company efforts to manage volatility in energy prices and reduce volatility risks for customers.

### **The Energy Efficiency Problem: Regulated Natural Gas Utilities are Penalized for Aggressively Promoting Energy Efficiency**

Local natural gas distribution companies (gas utilities) have very high fixed costs. These fixed costs include the costs of maintaining system safety and reliability throughout the year, staffing customer service telephone lines 24 hours a day and doing what it takes each day of the year to ensure the safe and reliable delivery of natural gas to homes, schools, hospitals, retailers, factories and other customers.

Natural gas utilities typically purchase natural gas on behalf of their customers, and pass through the cost without markup. This means that natural gas utilities do not

profit from their acquisitions of natural gas to serve customer needs. The profit (authorized level of rate of return) comes from the rates utilities charge for transporting the natural gas to customers' homes and businesses.

The vast majority of the non-commodity costs of running a gas distribution utility are fixed and do not vary significantly from month to month. However, traditional utility rates do not reflect this reality. Traditional utility rates are designed to capture most of approved revenue requirements for fixed costs through volumetric retail sales of natural gas, so that a utility can recover these costs fully only if its customers consume a certain minimum amount of natural gas (these amounts are normally calculated in rate cases and generally are based on what customers consumed in the past). Thus, many states' rate structures offer – quite unintentionally – a significant financial disincentive for natural gas utilities to aggressively encourage their customers to use less natural gas, such as by providing financial incentives and education to promote energy-efficiency and conservation techniques.

When customers use less natural gas, utility profitability almost always suffers, because recovery of fixed costs is reduced in proportion to the reduction in sales. Thus, conservation may prevent the utility from recovering its authorized fixed costs and earning its state-allowed rate of return. In this important respect, traditional utility rate practices fail to align the interests of utility shareholders with those of utility customers and society as a whole. This need not be the case. Public utility commissions should consider utility rate proposals and other innovative programs that reward utilities for encouraging conservation and managing customer bills to avoid certain negative impacts associated with colder-than-normal weather. There are a number of ways to do this, and NRDC and AGA join in supporting mechanisms that use modest automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales.<sup>1</sup> We also support performance-based incentives designed to allow utilities to share in independently verified savings associated with cost-effective energy efficiency programs.

Many states' rate structures also place utilities at risk for variations in customer usage based on variations in weather from a normal pattern. This variation can be both positive and negative. Utilities' allowed rate of return is premised on the

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<sup>1</sup>For example, in 2003 the Oregon Public Utility Commission approved a "conservation tariff" for Northwest Natural Gas Company (NW Natural) "to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict." The conservation tariff seeks to do that by using modest periodic rate adjustments to "decouple" recovery of the utility's authorized fixed costs from unexpected fluctuations in retail sales. See Oregon PUC Order No. 02-634, *Stipulation Adopting Northwest Natural Gas Company Application for Public Purpose Funding and Distribution Margin Normalization* (Sept. 12, 2003). In California, PG&E and other gas utilities have a long tradition of investment in energy efficiency services, including those targeting low-income households, and the PUC is now considering further expansion of these investments along with the creation of performance-based incentives tied to verified net savings. California also pioneered the use of modest periodic true-ups in rates to break the linkage between utilities' financial health and their retail gas sales, and has now restored this policy in the aftermath of an ill-fated industry restructuring experiment. Thus, in March 2004, Southwest Gas Company received an order that authorizes it to establish a margin tracker that will balance actual margin revenues to authorized levels.

expectation that weather will be normal, on average, and that customer use of gas will maintain a predictable pattern going forward. Proposals by utilities to decouple revenues from both conservation-induced usage changes and variations in weather from normal have sometimes been characterized as attempts to reduce utilities' risk of earning their authorized return. The result of these rate reforms, in this regulatory view, should be a lowered authorized return. But reducing authorized returns would penalize utilities for socially beneficial advocacy and action, including efforts to create mechanisms that minimize the volatility of customer bills.

Our shared objective is to give utilities real incentives to encourage conservation and energy efficiency. With properly designed programs, the benefits could be significant and widespread:

- Customers could save money by using less natural gas;
- Reduced overall use will help push down short-term prices at times when markets are under stress, reducing costs for all customers (whether or not they participate in the utility programs);
- Utilities would recover their costs and have a fair opportunity to earn their allowed return;
- State policies to encourage economic development could be enhanced by increased energy efficiency and lower business energy costs;
- State PUCs would be able to support larger state policy objectives as well as programs that reflect the public's desire to use energy efficiently and wisely.

In today's climate of rapidly changing natural gas prices, such reforms make good sense for consumers, shareholders, state governments, and the environment.

#### **Natural Gas Consumers, Price Volatility and Resource Portfolio Management.**

Another area of concern shared by NRDC and AGA is the impact of natural gas price volatility on natural gas consumers, which can be exacerbated by limited diversification of utilities' resource portfolios. Today many of the nation's natural gas utilities find themselves relying on short-term markets for most of their gas needs, with either the encouragement or the acquiescence of their regulators. During much of the 1990's this approach was typically advantageous to consumers, as the market price of natural gas was generally low and did not fluctuate dramatically. As wholesale natural gas prices have risen since 2000 and become more volatile, however, many utilities and commissions are reconsidering this emphasis on short-term market purchases.

While purchasing practices based on short-term supply contracts may offer consumers relatively low-cost natural gas, those consumers are also exposed to more volatile prices and natural gas bills that may rise and fall unpredictably. Public Utility Commissions should favorably consider gas distribution company proposals to manage volatility, such as through hedging, fixed-price contracts of various durations, energy-efficiency improvements in customers' buildings and equipment, and other measures designed to provide greater certainty about both supply



adequacy and price stability. Achieving these goals will sometimes require paying a premium over prevailing spot market prices. Like diversified investment portfolios that are designed to mitigate risk, prudent hedging plans should be encouraged as a way to help stabilize gas prices and ensure long-term access to affordable natural gas services.

**This Joint Statement also has been reviewed and endorsed by:**



**ALLIANCE TO  
SAVE ENERGY**  
*Creating an Energy-Efficient World*

**Alliance to Save Energy**



**American Council for an Energy-Efficient Economy**



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

39. Refer to the Blake Testimony, Exhibits MJB-8 through MJB-10 and MJB-12 through MJB-16.
- a. In rate cases, it would be common for analysts to use companies with characteristics similar to Delta's as proxies to obtain ROE estimates in rate cases. With the possible exception of a growth rate figure in Exhibit MJB-9, this does not appear to be the case for Dr. Blake. Provide an explanation of why a proxy group was not also included in estimating an appropriate ROE for Delta.
  - b. Explain how the companies, other than Delta, included in these exhibits are used, if at all, in the calculation of Delta's ROE recommendation.
  - c. Explain how each of the companies included in each of the exhibits is appropriate for use as a comparison to Delta.

RESPONSE:

- a. I chose the fifteen natural gas distribution companies included in the Edward Jones report as a panel because they represent a subset of all natural gas companies that was developed by an independent third party, and thus not subject to investigator bias. In its quarterly Financial and Common Stock Information report, Edward Jones classifies natural gas companies as "Diversified", "Combination" or "Distribution". Natural gas companies that are classified as "Distribution" have at least 90% of their net operating revenues from distribution. Natural gas companies that are classified as "Diversified" have at least 20% but less than 90% of their net operating revenues from distribution. Natural gas companies that are classified as "Combination" are electric utilities with at least 15% of their net operating revenues from regulated natural gas distribution. The common, similar characteristic that Delta shares with the other fourteen companies that are classified as "Distribution" by Edward Jones is that they all recover at least 90% of their net operating revenues from regulated natural gas distribution.

**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

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**DATED 6/07/07**

- b. My recommended allowed return on equity of 12.1% is based on a very simple calculation contained in the risk premium calculation shown in Exhibit MJB-13. All of the other calculations are performed to demonstrate to the Commission that this recommended return on equity is very reasonable for a micro-cap company such as Delta. I performed DCF and CAPM return on equity calculations for the other companies in the panel to provide a framework for the Commission to consider the return on equity that I am recommending in this proceeding. I believe that these calculations show that the 12.1% return on equity that I am recommending for Delta is fair and reasonable and should be adopted by the Commission.
- c. As indicated in response to item 39a above, the common, similar characteristic that Delta shares with the other fourteen companies that I use in my analysis is that they are all classified as "Distribution" by Edward Jones. This classification as "Distribution" means that they all recover at least 90% of their net operating revenues from regulated natural gas distribution. Additionally, this panel of natural gas distribution utilities was developed by an independent third party, Edward Jones Company, that has no interest to protect in this proceeding and therefore, is less likely to include or exclude companies to obtain a desired result.

Sponsoring Witness:

Martin J. Blake



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

40. Refer to the Blake Testimony, Exhibit MJB-8. Provide the data and calculations used to calculate the sustainable growth rate of 2.37 percent.

RESPONSE:

The sustainable growth rate is calculated by multiplying the allowed return on equity (10.5% in Exhibit MJB-8) by the retention ratio (0.2258 as calculated in Exhibit MJB-8).

$$10.5\% \times 0.2258 = 2.37\%$$

Sponsoring Witness:

Martin J. Blake



**DELTA NATURAL GAS COMPANY, INC.**  
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**DATED 6/07/07**

41. Refer to the Blake Testimony, Exhibit MJB-9. Explain why the Discounted Cash Flow calculations are valid when the stock prices and dividend are Delta's and the growth rate appears to be based on other companies.

RESPONSE:

The data source that I used, The Value Line Investment Survey - Small and Mid-Cap Edition, did not contain growth estimates for Delta or for any of the other companies contained in this data source. One of the purposes of using a panel is to provide data that may not be available for the company that you are analyzing. Using the average growth rate for the panel of companies with a reported growth rate in Value Line assumes that Delta is an average natural gas distribution company with respect to its dividend growth. To a certain extent the growth rate used by the Commission becomes a self fulfilling prophecy. If the Commission uses a low growth rate in calculating the allowed ROE, Delta's earnings will be low and the dividends that it will be able to pay to shareholders will also be low. If the Commission uses an average growth rate for natural gas distribution companies, Delta's earnings should be average, and the dividends that it can pay its shareholders should be around the average of other natural gas distribution companies. I used the average because I believe that it produces a fair result.

Sponsoring Witness:

Martin J. Blake





**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

42. Refer to the Blake Testimony, Exhibits MJB-12, MJB-14, and MJB-16. Reconcile the differences between the Capital Asset Pricing Model calculations for Delta.

**RESPONSE:**

The CAPM calculated in MJB-14 used a 20 year U.S. Treasury Bond Yield of 5.1% and a Long-Horizon expected equity risk premium of 7.2%. The CAPM calculated in MJB-12 used a 20 year U.S. Treasury Bond Yield of 5.0% and a Long-Horizon expected equity risk premium of 7.1%. The calculations contained in MJB-14 used preliminary data and should have been revised to reflect the final set of data used in the analysis. A revised Exhibit MJB-14 that calculates CAPM using a 20 year U.S. Treasury Bond Yield of 5.0% and a Long-Horizon expected equity risk premium of 7.1% is attached.

Sponsoring Witness:

Martin J. Blake

Revised Exhibit MJB-14

Estimated Return on Equity for Edward Jones Panel of Natural Gas Distribution Companies  
Using Sustainable Growth Rates for Small and Mid Cap Companies

Company Data Source	Beta	Dividend	Growth	High	Low	DCF Low	DCF High	CAPM
	1	1	1	Stock Price 1	Stock Price 1	Stock Price 2	Stock Price 2	
AGL Resources, Inc.	0.95	\$ 1.50	6.50%	\$ 40.00	\$ 34.40	10.86%	10.25%	12.85%
Cascade Natural Gas Corp.	0.85	\$ 0.96	0.50%	\$ 26.30	\$ 19.00	5.55%	4.15%	13.80%
Laclede Group	0.85	\$ 1.40	2.00%	\$ 37.51	\$ 29.10	6.81%	5.73%	13.37%
Peoples Energy Corp.	0.85	\$ 2.18	0.00%	\$ 45.21	\$ 34.90	6.25%	4.82%	12.77%
New Jersey Resources, Inc.	0.80	\$ 1.45	4.50%	\$ 53.16	\$ 41.50	7.99%	7.23%	12.35%
Piedmont Natural Gas Company	0.80	\$ 0.96	5.50%	\$ 28.44	\$ 23.20	9.64%	8.88%	12.41%
WGL Holdings, Inc.	0.80	\$ 1.35	2.00%	\$ 33.55	\$ 27.00	7.00%	6.02%	12.41%
Atmos Energy Corp.	0.75	\$ 1.26	2.00%	\$ 29.30	\$ 25.50	6.94%	6.30%	11.18%
Northwest Natural Gas Company	0.75	\$ 1.38	4.00%	\$ 43.69	\$ 32.80	8.21%	7.16%	12.00%
South Jersey Industries, Inc.	0.70	\$ 0.92	6.00%	\$ 34.26	\$ 25.60	9.59%	8.69%	12.30%
EnergySouth, Inc.	0.60	\$ 0.92	6.48%	\$ 41.53	\$ 26.40	9.96%	8.70%	13.65%
<b>Delta Natural Gas Company</b>	<b>0.55</b>	<b>\$ 1.20</b>	<b>2.37%</b>	<b>\$ 26.82</b>	<b>\$ 24.11</b>	<b>7.35%</b>	<b>6.84%</b>	<b>18.74%</b>
RGC Resources, Inc.	0.40	\$ 1.22	2.70%	\$ 28.14	\$ 22.72	8.07%	7.04%	17.67%
Energy West	0.35	\$ 0.48	3.18%	\$ 12.00	\$ 8.57	8.78%	7.18%	17.32%
						Mean	7.07%	13.77%
						Median	7.10%	12.81%

Data Sources:

1. The Value Line Investment Survey - Sep. 15, 2006
2. Risk Premium Over Time Report : 2006, Ibbotson Associates, 2006

## Revised Exhibit MJB-14

Estimated Return on Equity for Edward Jones Panel of Natural Gas Distribution Companies  
Using Sustainable Growth Rates for Small and Mid Cap Companies

Company	Shares	Market Equity		Dollar Return	
		High Stock Price	Low Stock Price	High Stock Price	Low Stock Price
AGL Resources, Inc.	77,878,889	\$ 3,115,155,560	\$ 2,679,033,782	\$ 319,303,445	\$ 290,955,529
Cascade Natural Gas Corp.	11,505,996	\$ 302,607,695	\$ 218,613,924	\$ 12,558,795	\$ 12,138,826
Laclede Group	21,357,000	\$ 801,101,070	\$ 621,488,700	\$ 45,921,821	\$ 42,329,574
Peoples Energy Corp.	38,471,441	\$ 1,739,293,848	\$ 1,342,653,291	\$ 83,867,741	\$ 83,867,741
New Jersey Resources, Inc.	28,080,314	\$ 1,492,749,492	\$ 1,165,333,031	\$ 107,890,182	\$ 93,156,442
Piedmont Natural Gas Company	75,277,250	\$ 2,140,884,990	\$ 1,746,432,200	\$ 190,014,834	\$ 168,319,931
WGL Holdings, Inc.	48,773,729	\$ 1,636,358,608	\$ 1,316,890,683	\$ 98,571,706	\$ 92,182,348
Atmos Energy Corp.	81,595,723	\$ 2,390,754,684	\$ 2,080,690,937	\$ 150,625,705	\$ 144,424,430
Northwest Natural Gas Company	27,548,346	\$ 1,203,587,237	\$ 903,585,749	\$ 86,160,207	\$ 74,160,147
South Jersey Industries, Inc.	29,232,801	\$ 1,001,515,762	\$ 748,359,706	\$ 86,985,123	\$ 71,795,759
EnergySouth, Inc.	7,936,000	\$ 329,582,080	\$ 209,510,400	\$ 28,658,039	\$ 20,877,394
<b>Delta Natural Gas Company</b>	<b>3,261,034</b>	<b>\$ 87,460,932</b>	<b>\$ 78,623,530</b>	<b>\$ 5,986,065</b>	<b>\$ 5,776,618</b>
RGC Resources, Inc.	2,130,573	\$ 59,954,324	\$ 48,406,619	\$ 4,218,066	\$ 3,906,278
Energy West	2,931,158	\$ 35,173,896	\$ 25,120,024	\$ 2,525,486	\$ 2,205,773

Company  
Data Source

1

Data Sources:

1. The Value Line Investment Survey - See
2. Risk Premium Over Time Report : 2006

Revised Exhibit MJB-14  
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Company	Book Equity	Return on Book Equity	Return on Book Equity
Data Source	1	High Stock Price	Low Stock Price
AGL Resources, Inc.	\$ 1,593,480,000	20.04%	18.26%
Cascade Natural Gas Corp.	\$ 123,517,500	10.17%	9.83%
Laclede Group	\$ 399,432,500	11.50%	10.60%
Peoples Energy Corp.	\$ 833,354,880	10.06%	10.06%
New Jersey Resources, Inc.	\$ 620,096,100	17.40%	15.02%
Piedmont Natural Gas Company	\$ 898,050,920	21.16%	18.74%
WGL Holdings, Inc.	\$ 927,208,800	10.63%	9.94%
Atmos Energy Corp.	\$ 1,646,237,800	9.15%	8.77%
Northwest Natural Gas Company	\$ 596,443,650	14.45%	12.43%
South Jersey Industries, Inc.	\$ 435,155,050	19.99%	16.50%
EnergySouth, Inc.	\$ 111,064,550	25.80%	18.80%
<b>Delta Natural Gas Company</b>	<b>\$ 51,697,650</b>	<b>11.58%</b>	<b>11.17%</b>
RGC Resources, Inc.	\$ 40,182,150	10.50%	9.72%
Energy West	\$ 18,863,520	13.39%	11.69%
Mean		14.70%	12.97%
Median		12.48%	11.43%

Data Sources:

1. The Value Line Investment Survey - Set
2. Risk Premium Over Time Report : 2006

**DELTA NATURAL GAS COMPANY, INC.  
CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST  
DATED 6/07/07**

42. Refer to the Blake Testimony, Exhibits MJB-12, MJB-14, and MJB-16. Reconcile the differences between the Capital Asset Pricing Model calculations for Delta.

**RESPONSE:**

The CAPM calculated in MJB-14 used a 20 year U.S. Treasury Bond Yield of 5.1% and a Long-Horizon expected equity risk premium of 7.2%. The CAPM calculated in MJB-12 used a 20 year U.S. Treasury Bond Yield of 5.0% and a Long-Horizon expected equity risk premium of 7.1%. The calculations contained in MJB-14 used preliminary data and should have been revised to reflect the final set of data used in the analysis. A revised Exhibit MJB-14 that calculates CAPM using a 20 year U.S. Treasury Bond Yield of 5.0% and a Long-Horizon expected equity risk premium of 7.1% is attached.

Sponsoring Witness:

Martin J. Blake

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Company Data Source	Beta	Dividend	Growth	High	Low	DCF Low	DCF High	CAPM
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Energy West	2,931,158	\$ 35,173,896	\$ 25,120,024	\$ 2,525,486	\$ 2,205,773				

1

## Data Sources:

1. The Value Line Investment Survey - See
2. Risk Premium Over Time Report : 2006



Revised Exhibit MJB-14

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Company Data Source	Book Equity 1	Return on Book Equity	
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Peoples Energy Corp.	\$ 833,354,880	10.06%	10.06%
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RGC Resources, Inc.	\$ 40,182,150	10.50%	9.72%
Energy West	\$ 18,863,520	13.39%	11.69%
	Mean	14.70%	12.97%
	Median	12.48%	11.43%

Data Sources:

1. The Value Line Investment Survey - Sep
2. Risk Premium Over Time Report : 2006



DELTA NATURAL GAS COMPANY, INC.  
CASE NO. 2007-00089

SECOND PSC DATA REQUEST  
DATED 6/07/07

43. Refer to the Blake Testimony, Exhibits MJB-12 and MJB-13. Explain how the 7.1 percent equity risk premium is calculated. In addition, provide the relevant pages from the Ibbotson Associates' *Risk Premium Over Time Report: 2006* as part of the response.

RESPONSE:

The 7.1% equity risk premium was obtained from Ibbotson Associates' *Risk Premium Over Time Report: 2006* which states that it is calculated by subtracting the long-term government bond income returns from the large company stock total return.

The relevant page from the Ibbotson Associates' *Risk Premium Over Time Report: 2006* where I obtained this estimate was included in my testimony as Exhibit MJB-6.

Sponsoring Witness:

Martin J. Blake



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

44. Refer to the Application, the Direct Testimony of William Steven Seelye ("Seelye Testimony"), page 4. Provide copies of the orders in Case Nos. GR-2006-0387 and GR-2006-0422 from the Missouri Public Service Commission.

**RESPONSE:**

Please see attached.

Sponsoring Witness:

William Steven Seelye

2007 Mo. PSC LEXIS 408, \*

In the Matter of Missouri Gas Energy's Tariffs Increasing Rates for Gas Service Provided  
to Customers in the Company's Missouri Service Area

Case No. GR-2006-0422; Tariff File No. YG-2006-0845

## PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

*2007 Mo. PSC LEXIS 408*

March 22, 2007, Issued; March 30, 2007, Effective

[\*1] APPEARANCES: Paul Boudreau; James Swearngen; Dean Cooper; Russ Mitten; Janet Wheeler; Diana Carter, Attorneys at Law; Brydon; Swearngen & England, 312 E. Capitol Avenue, Jefferson City, Missouri 65102, For Missouri Gas Energy, a division of Southern Union Company.; Stuart W. Conrad, Attorney at Law, Finnegan, Conrad & Peterson, LLC, 3100 Broadway Street, Suite 1209, Kansas City, Missouri 64111, For Midwest Gas Users Association.; Jeremiah D. Finnegan, Attorney at Law, Finnegan, Conrad & Peterson, LLC, 3100 Broadway Street, Suite 1209, Kansas City, Missouri 64111, For Central Missouri State University, University of Missouri-Kansas City and Jackson County.; Mark W. Comley, Attorney at Law, Newman, Comley & Ruth, 601 Monroe, Suite 301, Post Office Box 537, Jefferson City, Missouri 65102, For the City of Kansas City.; Jeffrey Keevil, Attorney at Law, Stewart & Keevil, 4603 John Garry Drive, Suite 11, Columbia, Missouri 65203, For Trigen-Kansas City Energy Corporation.; Marc Poston, Attorney at Law, Office of the Public Counsel, Post Office Box 2230, Jefferson City, Missouri 65102, For the Office of the Public Counsel and the public.; Kevin A. Thompson, Robert Franson, Lera Shemwell, [\*2] Robert Berlin, David Meyer, Steven Reed, Attorneys at Law, Governor Office Building, Suite 800, 200 Madison Street, Jefferson City, Missouri 65102, For the Staff of the Missouri Public Service Commission.

**PANEL:** Kennard L. Jones, REGULATORY LAW JUDGE; Davis, Chm., Murray, Appling, CC., concur; Gaw, C., dissents, with separate dissenting opinion to follow; Clayton, C., dissents

**OPINIONBY:** JONES

**OPINION: REPORT AND ORDER**

**Summary**

In this report and order, the Commission finds that Missouri Gas Energy, a division of Southern Union Company, is entitled to a rate increase sufficient to generate a revenue increase of approximately \$ 27,206,968.

**FINDINGS OF FACT**

The Missouri Public Service Commission, having considered all of the competent and substantial evidence upon the whole record, makes the following findings of fact.

**Procedural History**

On May 1, 2006, Missouri Gas Energy, a division of Southern Union Company, filed tariff sheets designed to implement a general rate increase for natural gas service in the amount of \$ 41,651,345. The tariff sheets carried an effective date of June 2, 2006.

On May 12, 2006, the Commission suspended MGE's tariff until March 30, 2007. The maximum amount [\*3] of time allowed for suspension under the controlling statute. n1 The Commission also directed that notice of MGE's tariff filing be provided to the public, setting June 1, 2006, as the deadline for the submission of applications to intervene.

n1 Section 393.150, RSMo 2000.

The Commission granted timely applications to intervene that were filed by Trigen-Kansas City Energy Corporation, Midwest Gas Users Association, University of Missouri-Kansas City and Central Missouri State University. The Commission also granted requests to intervene, filed out of time, by The City of Kansas City, Missouri and the County of Jackson, Missouri. The Commission denied an untimely request to intervene by Cornerstone Energy, Inc. The Commission found that the former out-of-time requests were supported by good cause, while the latter was not.

On July 13, 2006, the Commission established the test year for this case as the 12-month period ending December 2005, updated for known and measurable changes [\*4] through June 30, 2006. The parties also settled on a further true-up period through October 31, 2006, for the purpose of updating certain cost components. Also in its order, the Commission established a procedural schedule with the first day of the hearing beginning on January 8, 2007.

The Commission conducted local public hearings at which the Commission heard comments from MGE's customers regarding MGE's request for a rate increase. The hearings were held in Kansas City, Joplin, Republic, Warrensburg, Nevada, St. Joseph and Slater, Missouri.

The parties prefiled direct, rebuttal and surrebuttal testimony. The evidentiary hearing began on January 8, 2007, and continued through January 17. True-up testimony was entered into the record during the course of the hearing and with consent of all of the parties the true-up hearing was canceled as being unnecessary.

### **Partial Stipulations and Agreements**

Prior to the start of the evidentiary hearing, MGE, Staff, OPC, MGUA, UMKC, CMSU and the County of Jackson, Missouri submitted a Partial Nonunanimous Stipulation and Agreement with regard to customer class cost of service. Although the City of Kansas City and Trigen did not enter the agreement, [\*5] they did not oppose it. The Commission approved the agreement. The Commission also approved an unopposed Partial Nonunanimous Stipulation and Agreement, filed by MGE and Staff, concerning depreciation schedules.

### **Overview**

MGE is a division of Southern Union Company. As a division, MGE has no separate corporate existence apart from Southern Union. MGE's divisional headquarters is located in Kansas City, Missouri and provides service to customers in Kansas City, St. Joseph, Joplin and other cities in western Missouri. MGE is a local distribution company, sometimes referred to by the acronym, "LDC." That means that MGE purchases natural gas from a supplier, pays to transport the gas to Missouri over one or more interstate pipelines, and then distributes the natural gas to its customers in this state. Southern Union is headquartered in Wilkes-Barre, Pennsylvania. In addition to MGE, Southern Union has one other division in New England that acts as an LDC.

Noted earlier, as an LDC, MGE must purchase natural gas from supply sources, transport the gas over an interstate pipeline, and then distribute it to its customers. This Commission does not have any authority to regulate the price [\*6] that MGE must pay to purchase and transport gas over the interstate pipeline. The purchase price of natural gas is set by the market and transportation rates are regulated by the Federal Energy Regulatory Commission (FERC). As a result, this rate case has nothing to do with those aspects of the cost of natural gas.

The price that MGE must pay to purchase and transport natural gas is passed through, dollar for dollar, to its customers through the PGA/ACA process. Therefore, if MGE is to recover its cost of distributing natural gas to its customers, and earn a profit, it must have another source of income. It is those costs, and that source of income, that are at issue in this rate case.

MGE began the rate case process when it filed its tariff on May 1, 2006. In doing so, MGE asserted that it was entitled to increase its rates enough to generate an additional \$ 41,651,345 in general revenues per year. MGE set out its rationale for increasing its rates in the direct testimony that it filed along with its tariff on May 1. In addition to its filed testimony, MGE provided work papers and other detailed information and records to the Staff of the Commission, Public Counsel and other intervening [\*7] parties to determine whether the requested rate increase is just and reasonable.

Because of the complexity of a rate case, there are a multitude of matters about which the parties could disagree. However, there was agreement between the parties about many matters; hence, those potential issues were not brought before the Commission. Where the parties disagreed, they prefiled written testimony for the purpose of bringing those issues to the attention of the Commission. All parties were given an opportunity to prefile three rounds of testimony - direct, rebuttal, and surrebuttal. Prior to the start of the hearing, the parties submitted a Joint Statement of Issues that required resolution by the Commission.

As noted, the issues of depreciation and class cost of service were resolved by Stipulation and Agreement and will not be further addressed in this report and order. The remaining issues will be addressed in turn. The issue description for each issue is taken from the statement of issues. Factual matters will be addressed in the Findings of Fact section. If an issue also contains a legal aspect, that portion of the issue will be addressed in the Conclusions of Law section.

Generally, [\*8] all parties agree that MGE has experienced a revenue deficiency. However, this does not mean that MGE operated at a loss. In fact, it did earn a return of between 5.74% and 8.29%. n2 For the calendar year of 2005 MGE's overall rate of return was 7.49%. And for 2006 it was considerably lower due to weather being 77% of normal. n3

n2 Transcript, Page 950, Lines 12-24.

n3 Transcript, Page 590, Lines 12-16.

## The Issues

### 1. Capital Structure

*Issue Description: What is the appropriate capital structure (i.e., the relative proportions of long-term debt, short-term debt, preferred equity, and common equity) to use in calculating MGE's cost of service?*

Determining an appropriate capital structure for MGE is complicated by the fact that MGE is a division of Southern Union and does not issue its own debt or equity. Therefore, MGE does not have its own capital structure.

As a substitute for its non-existent capital structure, MGE proposes to use a hypothetical capital structure consisting of 46% equity [\*9] and 54% debt. MGE's proposed structure is as follows: n4

Common Equity	46%
Long-Term Debt	44.09%
Short-Term Debt	9.91%

However, if the Commission does not adopt the proposed hypothetical capital structure, MGE is willing to accept the actual capital structure of Southern Union as of October 31, 2006. n5

n4 Hanley Direct, Ex. 1, Page 3.

n5 Transcript, Page 170, Lines 17-23.

Southern Union has an identifiable capital structure. n6 Staff recommends that the Commission use the actual consolidated capital structure of Southern Union, as of October 31, 2006. The following is the capital structure offered by Staff: n7

Common Equity	36.06%
Long-Term Debt	55.92%
Preferred Stock	4.71%
Short-Term Debt	3.3%

OPC did not take a position on this issue.



n6 Transcript, Page 60, Line 24.

n7 Murray True-Up, Ex. 205, Page 3, Lines 1-3.

[\*10]

It is important to note that the capital structure recommended by Staff contains a much smaller proportion of common stock than does the structure recommended by MGE. It costs the company more to issue equity than it does to incur debt. Therefore, a capital structure that uses a lot of debt with relatively low levels of equity is less expensive for the company. That means, all else being equal, a capital structure that includes a low percentage of equity and a large percentage of debt will be less costly, resulting in a lower rate of return, and consequently a lower revenue requirement and lower rates to customers.

However, a high percentage of debt in a capital structure has an effect on the cost of equity. The shareholders in a company - the holders of equity - are subordinate to holders of debt. Generally, the company must pay the interest on debt, such as bonds issued by the company, before it can pay dividends to its shareholders or before it can invest profits in other ways that benefit the shareholders. If a company's gross income goes down, the risk is borne by the shareholders. Furthermore, if the company has to be liquidated, the holders of debt get paid first. The shareholders [\*11] get whatever is left over. Therefore, a company with a capital structure that includes a high percentage of debt is more risky for shareholders. The shareholders will consequently demand a higher rate of return to compensate them for the increased risk caused by the high level of debt.

Southern Union's capital structure, as proposed by Staff, contains a good deal more debt and less equity than the capital structure proposed by MGE. That means the capital structure proposed by Staff poses more risk to the shareholder than that proposed by MGE. MGE contends that the use of its proposed capital structure, one using proxy companies to reflect the capital structure of a stand-alone LDC, is particularly appropriate in light of Southern Union's transition to being primarily a transportation and storage company.

This issue was discussed by the Commission in MGE's last rate case. n8 As discussed in that case, the capital structure of Southern Union is the result of its management decisions. Hence, Southern Union, and ultimately MGE, must operate with the result of its decisions. MGE stresses that the make-up of Southern Union has changed so dramatically, that use of a hypothetical capital [\*12] structure is warranted. This premise, however, does not change the Commission's reasoning in MGE's last rate case. Therefore, the capital structure, as proposed by Staff, shall be used.

n8 Report and Order, Commission Case No. GR-2004-0209, issued, September 21, 2004.

## 2. Rate Design

*Issue Description: What is the appropriate rate design for residential, small general service, large volume service and large general service classes?*

Historically, MGE has operated under a rate design that allows it to recover a portion of its fixed cost through a customer charge. The remaining portion is recovered through volumetric rates, the amount of gas MGE sells to its customers. Currently, MGE recovers 55% of its fixed cost through a customer charge and 45% of its fixed cost through volumetric rates. n9 Since 1996, the annual average usage per residential customer has generally declined. n10 MGE posits that because of this decline, coupled with the fact that 90% of its customer base is residential, it has been [\*13] unable to earn its Commission authorized rate of return. n11 Hence, MGE seeks Commission approval of a Straight-Fixed Variable (SFV) rate design for the Residential class because of the under-recovery of its costs through volumetric rates and because of the high degree of heat sensitivity effecting the class. n12 The SFV design is one through which the company will recover all of its fixed costs through a fixed, monthly customer charge. Although its preferred rate design is the SFV design, as an alternative MGE proposes a design consisting of a weather normalization adjustment mechanism applicable to Residential, Small General Service and Large General Service classes. n13 The only class omitted is the Large Volume Service class.

n9 Transcript, Page 634, Lines 2-5.

n10 Feingold, Schedule RAF-7.

n11 Transcript, Page 632, Pages 2-8.

n12 Transcript, Page 686, Lines 14-23.

n13 Transcript, Page 16, Lines 19-23.

Staff agrees that the SFV design should be implemented. n14 Staff argues that customers [\*14] in the Residential class are homogeneous with respect to the cost of serving them and that it is unfair to collect these costs through a volumetric rate design. n15 Staff goes on to reason that the volumetric rate design causes high-use customers to subsidize the cost of low-use customers. Staff also reasons that the SFV design will reduce volatility of customer bills. An additional benefit of the proposed rate design, set out by Staff and the company, is that the objective of the shareholders and ratepayers will be better aligned because the utility's revenues will no longer depend on how much gas it sells. Currently, MGE has an incentive to sell more gas to at least recover its costs. The current rate design therefore discourages natural gas conservation efforts on the part of the company. If the SFV design is adopted, the company is committed to offering several natural gas conservation initiatives. Finally, the SFV design will promote accuracy. Under the current design, presumptions are made about sales volumes to try to match MGE's fixed cost. In this instant, there is often over or under payment. The proposed rate design eliminates this concern with regard to the Residential [\*15] class.

n14 Staff Post Hearing Brief, Page 18.

n15 Staff's Post Hearing Brief, Page 18.

OPC opposes any change in the current rate design. n16 Although OPC opposes the SFV design, as a participant in an energy task force it agreed that the Commission should incorporate rate designs that remove the disincentive for utilities to pursue programs aimed as reducing usage. n17 OPC's recommendation in support of the current rate design does not remove the company's disincentive to pursue programs aimed as reducing natural gas usage. n18 As discussed above, the SFV rate design does just that. Also, as discussed above, declining customer usage coupled with the current rate design, will exacerbate MGE's inability to recover its fixed costs. OPC does not dispute that customer usage is declining and will continue to do so through 2010 to 2020, as put forth by MGE's witness in light of a forecast set out by the American Gas Association. n19

n16 Transcript, Page 562, Pages 6-16.  
[\*16]

n17 Transcript, Page 566, Lines 4-10.

n18 Transcript, Page 537, Lines 10-15.

n19 Transcript, Page 534, Lines 1-18.

Although OPC opposes the SFV design because it lessens the customer's ability to have control over the amount of his or her bill, n20 OPC agrees that that under the SFV design customers would save by reducing their natural gas usage. n21 Further, OPC agrees that customers will not pay as much in colder-than-normal winters. n22 Under the SFV

design, weather is removed from the risk factor calculation. n23 OPC opposed the SFV design as unjustifiable in a separate matter because the company had not proposed any meaningful conservation programs. n24 Notwithstanding, in this matter MGE has proposed conservation programs. Also, MGE has had in place a Low Income Weatherization program for some time. n25 Lastly, OPC particularly opposes the SFV design in conjunction with tariff language regarding seasonal disconnects, n26 which will be discussed below.

n20 Transcript, Page 537, Lines 10-18.

n21 Transcript, Page 580, Lines 23-25.

[\*17]

n22 Transcript, Page 579, Lines 14-18.

n23 Transcript, Page 92, Lines 6-12.

n24 Transcript, Page 541, Lines 4-9.

n25 Transcript, Page 541, Lines 10-13.

n26 Transcript, Page 571, Lines 15-18.

The Commission points out that MGE and Staff propose a SFV design only for MGE's Residential class and not for its Small General Service class because it is more heterogeneous than the Residential class. n27 The Commission finds MGE and Staff's arguments for a rate design that will protect MGE from the vagaries of weather to be persuasive. The Commission shall approve the SFV rate design for MGE's residential class.

n27 Transcript, Page 684, Lines 13-20.

### 3. Unrecovered Cost of Service Amortization

*Issue Description: Should MGE recover \$15.6 million in rates amortized over five years for alleged revenue loss due to lower customer gas use for the period of January through June of 2006?*

Staff and OPC [\*18] argue that to authorize this expense would constitute retroactive ratemaking. n28 MGE agrees that to grant this request would constitute retroactive ratemaking. n29 Because all parties of interest n30 agree that this request is illegal, the Commission will deny MGE's proposal.

n28 Transcript, Page 1006, Lines 8-12.

n29 Transcript, Page 284, Lines 19-25.

n30 The only parties arguing this issue are MGE, Staff and OPC.

### 4. Property Tax Refund

**Issue Description:** *What is the proper treatment of \$ 5,554,068 in property tax refunds received by MGE during the test year of 2005?*

During the test year of 2005, MGE received a refund of property taxes paid during 2002, 2003 and 2004. Staff proposes to put that money in a deferred account and to amortize it over five years; reducing the amount of property tax expense that would otherwise be included in rates. n31 Staff contends that to do so does not constitute retroactive rate-making because the money was received during the test year. n32 However, Staff [\*19] contends that in this regard, rates were properly set for the years 2002, 2003, and 2004. n33 Then Staff goes on to state that in light of the company having recovered the taxes, this expense was set too high in rates. n34 In setting rates, there is always a risk that the expense for property taxes will be under or over estimated. The company therefore has the risk of not recovering its property taxes. In this case, the property tax expense was set too high, just as cost of service was set too low in the preceding issue.

n31 Transcript, Page 848, Lines 12-20.

n32 Transcript, Page 850, Lines 21-25.

n33 Transcript, Page 851, Lines 21-22.

n34 Transcript, Page 854, Lines 3-4.

MGE argues that Staff's proposal constitutes retroactive ratemaking and that the Missouri Supreme Court has determined, in setting rates, that the Commission can consider past excess recovery by a utility only insofar as it is relevant to a determination of what rate is necessary to provide a just and reasonable return. n35 Interestingly, [\*20] Staff notes in its opening argument that "the test year concept is to take a snapshot of the company's incoming revenues and outgoing expenses and work with those to determine the appropriate rates." Although Staff goes further to propose inclusion of the refund in rates, Staff's statement is consistent with the argument put forth by MGE.

n35 Transcript, Page 855, Lines 11-17.

Based on its Conclusions of Law and the above findings, the Commission will deny Staff's request to amortize the property taxes refunded to MGE in 2005.

## 5. Weather Normalization

**Issue Description:** *What is the appropriate measure of normal weather to be used in calculating 1) MGE's revenue requirement and 2) the billing determinants to be used in establishing MGE's volumetric rate elements?*

The Commission has historically used a 30-year average in determining what the normal temperature should be. n36 Staff gathers its information from the National Oceanic Atmospheric Administration (NOAA). Currently, the NOAA's period for calculating [\*21] a normal climate is the 30-year period between January 1, 1971 and December 31, 2000. n37 The "normal" temperature is ultimately used to determine what the cost of each unit of gas should be. MGE proposes to use what is described as a 10-year rolling average to determine normal weather.

n36 Transcript, Page 671, Line 25 Page 672, Line 2

n37 Transcript, Page 675, Lines 22-25.

MGE argues Staff's recommendation of the 30-year period is flawed because Staff's proposal fails to consider circumstances that reasonable can be expected to occur while rates are in effect. n38 MGE goes on to argue that "the theory underlying the policy should generate a result that has some relationship to reality; otherwise, what we do here is just a formality." n39 MGE points out that if the Commission adopts the SFV rate design, weather normalization will not be an issue for its residential customers. n40

n38 Transcript, Page 665, Lines 2-7.

n39 Transcript, Page 668, Lines 9-11.

[\*22]

n40 Transcript, Page 668, Lines 14-21.

Staff has problems with the 10-year normal because it's too short to provide the necessary stability. Temperature variations can span across decades. Also, the rolling average will change every year and depending on which year is the test year we could end up with different normals. n41 Staff's position is that the 30-year normal is a better reflection than the 10-year rolling average of what is normal. n42

n41 Transcript, Page 742, Lines 16-25.

n42 MGE's current tariff. P.S.C Mo. No. 1, Fourth Revised Sheet No. 96.

As noted above, the Commission has historically used the 30-year normal. As MGE has stated, under the SFV rate design this will not be an issue for 90% of the company's customers. The Commission continues to use the 30-year normal and finds that it should be consistent when applying a method of weather normalization between utilities. In the absence of more convincing evidence [\*23] that this methodology should be changed, the Commission will continue to adopt the 30-year weather normalization as proposed by Staff.

## 6. Low Income Weatherization

*Issue Description: What is the appropriate level of low-income weatherization funding to be used in calculating MGE's cost of service and how should such funding be allocated among the geographic regions of MGE's service territory?*

MGE currently provides \$ 367,000 of ratepayer funds to the weatherization program in Clay, Platte and Jackson Counties. n43 An additional \$ 132,368 is administered throughout the rest of MGE's service territory for a total of \$ 500,000. The program was initiated in 1994 and currently serves between 200-300 customers per year. n44 Among other things, the program includes appliance replacement, installation of insulation and energy audits. n45 As a result of demand for the program, the City of Kansas City, the program administrator, requests an additional \$ 250,000. Kansas City states that the funds are exhausted before the end of each year. n46 Approximately \$ 1,700 per person is spent through the program. n47 Kansas City states that it will be able to serve an additional 100-150 [\*24] customers with the additional \$ 250,000.

n43 Transcript, Page 132, Lines 15-16.

n44 Transcript, Page 135, Lines 17-19.

n45 Transcript, Page 137, Lines 18-24.

n46 Transcript, Page 134, Lines 6-16.

n47 Transcript, Page 136, Lines 10-11.

Staff and MGE support additional funding for the program. However, they agree that the additional funding should be \$ 100,000 rather than \$ 250,000. Further, at Staff's suggestion, they agree that an additional \$ 20,000 should be used to evaluate the program's effectiveness. n48 MGE states that the \$ 100,000 increase is sufficient in light of the fact that Kansas City does not have much of a backlog and that a 20-25% increase at this time makes sense. n49

n48 Transcript, Page 811, Lines 7-13.

n49 Transcript, Page 625, Lines 2-14.

The Commission finds that the existing low-income weatherization [\*25] program has been successful and should be continued with additional funding. In light of the growing concern regarding energy conservation, the Commission will direct MGE to fund the low-income weatherization program with an additional \$ 250,000 to be allocated in the same proportion as the current program.

## 7. Natural Gas Conservation

*Issue Description: Should funding for natural gas conservation programs be included in MGE's cost of service?*

As discussed earlier, under the SFV rate design, MGE's disincentive to promote natural gas conservation is removed. With the disincentive removed, the company is willing to "offer" conservation programs to better align themselves with the interest of the customer. n50 The company offers \$ 705,000 to be included in rates to go toward a gas water heater rebate program. n51 The Commission notes, however, that this program is particularly in the company's interest as it provides an incentive for customers to switch from electric to gas water heaters. n52 Additionally, the company is offering \$ 45,000 to be included in rates to educate the public about energy conservation. n53 This program would be an on-line audit (energy calculator) [\*26] linked to the Department of Energy. n54 MGE anticipates lowering its return requirement by \$1 million under the SFV design and using that money for conservation programs. n55 The Commission shall approve the conservation program proposed by Staff and MGE.

n50 Transcript, Page 390, Lines 20-25.

n51 Transcript, Page 440, Lines 9-11.

n52 Transcript, Page 441, Line 23 - Page 442, Line 4.

n53 Transcript, Page 439, Lines 7-25.

n54 Transcript, Page 627, Lines 3-10.

n55 Transcript, Page 808, Lines 6-25.

## 8. Environmental Response Fund

*Issue Description: Should the environmental response fund proposed by MGE be adopted and what, if any, level of environmental costs should be used in calculating MGE's cost of service? MGE requests that the amount of the fund be \$ 500,000, annually.*

MGE is seeking authority to establish an environmental response fund of \$ 500,000 annually, through rates, to meet its obligation to pay costs associated with several manufactured gas sites purchased [\*27] by Southern Union. n56 The company proposes that \$ 500,000 be set aside every year until such time as the costs are incurred. n57 MGE agrees that the costs associated with the clean-up are impossible to know. n58 MGE's contractual obligation with regard to the clean up of these sites is to seek rate recovery. n59 This proposal was rejected when presented to the Commission in MGE's last rate case. n60 The premises underlying that discussion have not changed.

n56 Transcript, Page 885, Lines, 15-22.

n57 Transcript, Page 918, Lines 14-17.

n58 Transcript, Page 899, Lines 8-13 and Page 909, 23-25.

n59 Transcript, Page 904, Lines 23-25.

n60 Transcript, Page 917, Lines 12-16.

In the future, MGE may incur an unknown and unknowable amount of financial liability for the cleanup of environmental hazards left over from the operation of manufactured gas facilities 100 to 125 years ago. n61 Manufactured gas facilities were used before the advent of interstate natural gas pipelines in the 1940s. Before there [\*28] were interstate pipelines, gas could not be transported over long distances so gas companies manufactured gas by heating coal or oil and collecting the gas that was driven off in the process. The primary byproduct that came from this process is tar, which contains hazardous carcinogens. This is what primarily drives investigation and remediation of the sites. n62 MGE agrees that it is not possible to ascertain the costs of investigation and remediation. n63 That the magnitude of the costs associated with this effort is impossible to know is again noted by MGE. n64 Further, to date, MGE has not paid any costs associated with the environmental clean up. n65

n61 Transcript, Page 900, Lines 1-3.

n62 Transcript, Page 895, Lines 2-9.

n63 Transcript, Page 896, Line 23 Page 897, Line 6.

n64 Transcript, Page 899, Lines 8-13.

n65 Transcript, Page 908, Lines 12-17.

That these costs are not known and measurable precludes their inclusion in rates. Furthermore, the creation of a pre-funded source for [\*29] the payment of these cleanup costs would remove much of Southern Union's incentive to ensure that only prudently incurred and necessary costs are paid. If the money has already been recovered from ratepayers and is being held in the Fund, Southern Union would have little incentive to not pay it out to settle claims brought against it. Although the Fund would be subject to audit by Staff and Public Counsel and they could seek a prudence adjustment, the need for a prudence adjustment is difficult to prove and is not a good substitute for the company's own desire to prudently minimize its costs to improve its bottom line. For these reasons, the Commission finds that MGE's proposal to create an Environmental Response Fund shall be rejected.

## 9. Infinium Software

**Issue Description:** *Should the Unrecovered cost associated with MGE's Infinium Software be included in rates through an amortization and, if so, over what period of time?*

MGE purchased the Infinium Software in 1995 and the estimated life was 10 years. The company switched to different software, Oracle, in 2005. n66 Although the original investment was almost fully amortized, each year after 1995, until 2001, enhancements [\*30] and modifications were made to the Infinium system. Each enhancement was given a new 10-year life rather than being amortized for the remaining life of the Infinium system. n67 MGE is now requesting amortization of the remaining balance of the entire system, n68 which is approximately \$1.23 million. n69

n66 Transcript, Page 1264, Lines 2-8.

n67 Transcript, Page 1264, Lines 11-21.

n68 Transcript, Page 1260, Lines 14-16.

n69 Transcript, Page 1035, Line 12-13.

The enhancements to the system were included in rate base in MGE's last rate case in 2004. n70 MGE is currently earning a return on those enhancements until they come out of rate base. n71 MGE points out that it continues to use the Infinium Software for a time entry system, which it intends to do until March of 2007 if it converts the payroll system over to Oracle. n72

n70 Transcript, Page 1266, Line 23 Page 1267, Lines 2.

n71 Transcript, Page 1267, Lines 21-24.

[\*31]

n72 Transcript, Page 1257, Lines 9-18.

OPC argues that the system is not used and useful and opposes MGE's proposal. n73 In this regard, OPC refers to *State ex rel. Union Electric v. P.S.C., 765 S.W.2d 618 (Mo. App. 1988)* in its post hearing brief. That case states that:

The property upon which a rate of return can be earned must be utilized to provide service to its customers. That is, it must be used and useful. This used and useful concept provides a well-defined standard for determining what properties of a utility can be included in rate base.

n73 Transcript, Pages 1284 -1285.

However, MGE made an adjustment to remove the plant investment in the software out of its rate base, which means MGE will not earn a return on the plant. n74 With the concept of "use and useful" being the premise of OPC's opposition, its argument must be rejected. Both Staff and MGE point out that the plant is [\*32] not included in rate base. Therefore, the company will not earn a return on the property. The concept of "used and useful" thus becomes irrelevant. The Commission finds that the property shall be amortized over 5 years as proposed by Staff and MGE.



n74 Transcript, Page 1266, Lines 15-20 and Page 1267, Lines 6-9.

## 10. Rate Case Expense

*Issue Description: What is the appropriate amount and treatment of rate case expense, including amortization of prior rate case expense, in this case?*

From MGE's last rate case in 2004, the Commission authorized the company to amortize its rate case expense over three years. A balance of \$ 148,971 remains to be amortized as of March 2007. n75 MGE proposes to amortize the current rate case expense with the remaining \$ 148,971 over a three-year period. n76 Although in its pre and post hearing briefs Staff argues that to allow MGE to amortize the remaining rate case expense would constitute retroactive rate-making, there is no mention of this argument during the hearing. [\*33] In fact, Staff's position is that the rate case expense be normalized. n77 The Commission will therefore disregard Staff's argument that recovery of this expense would constitute retroactive ratemaking.

n75 Transcript, Page 1040, Lines 1-3.

n76 Transcript, Page 1044, Lines 10 -13.

n77 Transcript, Page 1045, Lines 21 24.

The Commission resolved this issue in MGE's last rate case to allow the company to recover, what was determined to be prudent costs, through amortization over three years. The Commission will not vacate its order in that regard. Staff and MGE propose to amortize the remaining rate case expense with that incurred in this case. The Commission will grant that request and allow MGE to amortize the combined amounts over a three-year period.

## 11. Emergency Cold Weather Rule AAO Recovery

*Issue Description: What is the proper rate treatment for costs deferred under the Emergency Cold Weather Rule AAO Recovery Mechanism?*

MGE is requesting about \$ 900,000 through an AAO as a result [\*34] of complying with the Emergency Cold Weather Rule. n78 On September 21, 2006, the Commission issued an order granting authority for an AAO for cost incurred under the cold-weather rule. In that order, the Commission directed the parties to brief and present testimony on this issue.

n78 Transcript, Page 1074, Line 11.

Staff testified that \$ 901,331 represents the difference between the amount that the company could have collected under the old cold weather rule and the amount that MGE actually collected. n79 Staff recommends that this amount be amortized over three years. n80 Consistent with the Commission's order of September 21, 2006, the Commission will grant MGE's request to amortize the deferred cost through an AAO and finds that \$ 901,331 shall be amortized over a three-year period.

n79 Harrison Direct, Page 17, Lines 7-9.

n80 Harrison Direct, Page 17, Lines 20-21.

[\*35]

## 12. Seasonal Disconnects

*Issue Description: Should the seasonal disconnect tariff language proposed by MGE be approved?*

Of its 450,000 customers, MGE has about 1,275 customers who voluntarily disconnect their service for period of up to seven months. MGE seeks approval to include in its tariff, language that will require those who "seasonally" disconnect to pay their portion of the fixed costs to provide service that they would have otherwise paid had they remained on the system. The customer would also have to pay the already-approved \$ 45 reconnection fee. The maximum a customer would have to pay to be reconnected after voluntarily disconnecting for 7 months would be \$ 237.50. n81 Staff calculated this figure to be \$ 209.36. n82 Based on a SFV rate design, MGE estimates that the cost of those who seasonally disconnect is about \$ 140,000. n83 Staff estimates this figure to be \$ 114,447. n84

n81 Transcript, Page 1095, Lines 8-20.

n82 Transcript, Page 1113, Lines 4-6.

n83 Transcript, Page 1085, Lines 14-17

n84 Transcript, Page, 1113, Lines 4-6.

[\*36]

MGE recognizes that today, this is not a substantial issue. MGE's intent is to discourage seasonal disconnection in the future. n85 However, there is no proposed language to protect customers who voluntarily disconnect for hospital stays, military obligations, or for students who vacate in the summer to return in the fall. n86 OPC argues that the proposed language will force customers to pay for a service they did not use during the time of disconnection, and it fails to take into account the various reasons a customer would need to be disconnected. n87

n85 Transcript, Page 599, Lines 12-14.

n86 Transcript, Page 1094, Lines 20-24.

n87 Transcript, Page 1149, Lines 3-7.

Currently, customers pay a fixed charge of \$ 11.65 per month. According to MGE, under the SFV rate design, this figure could increase to \$ 27.50. n88 Essentially, MGE requests that the fixed monthly charge be increased while proposing language that punishes customers for disconnecting during a time of the year when gas is not needed. MGE's [\*37] intent is to discourage people from disconnecting. However, under the higher fixed charge the opposite might occur. There is no way to predict what effect a SFV rate design will have on seasonal disconnection.

n88 Transcript, Page 1103, Line 6.

What is certain is that this currently not a big problem for MGE. Those who seasonally disconnect represent only .3% of MGE's residential customer base. The Commission realizes that it recently approved seasonal disconnection language in Atmos Energy Corporations' rate case. n89 However, in that case the customers who took advantage of seasonal disconnection comprised 10% of the company's residential customers. Also, the Atmos reconnection charge, at \$ 24.00, is substantially lower than that of MGE. These distinctions justify the Commission taking a different course in this case. The Commission will, therefore, deny MGE's request to include language in its tariff regarding seasonal disconnection.

n89 Commission Case No. GR-2006-0387. Report and Order, issued February 22, 2007.

[\*38]

### 13. Kansas Property Tax AAO

*Issue Description: Should the Kansas Property Tax AAO be continued past the expiration date ordered by the Commission in Case No. GU-2005-0095?*

In Case No. GU-2005-0095, the Commission granted MGE an Accounting Authority Order allowing it to record on its books a regulatory asset representing the expenses associated with property taxes. The property tax concerns natural gas storage held by MGE in the state of Kansas. n90 MGE contends that it should not have to pay the tax and informs the Commission that the matter is now before the Supreme Court of Kansas.

n90 Transcript, Pages 1288-1289.

Staff agrees with MGE that there is no reason to vacate the Commission's prior Order. It also agrees that this issue involves no money and will make no difference with regard to revenue requirement. n91 OPC opposes this request arguing that the AAO is inappropriate because the costs to be deferred are not known and measurable. n92

n91 Transcript, Page 1291, Lines 9-19.

[\*39]

n92 Robertson Direct, Page 19.

In its order initially granting the AAO, the Commission reasoned that an AAO is appropriate if MGE demonstrates that the costs to be deferred are "extraordinary, unusual and unique, and not recurring." In this case, the costs that MGE seeks to continue deferring are property taxes. In most cases, the payment of property taxes by a utility would not be a fit subject for an AAO. MGE, like all investor-owned utilities, routinely pays property taxes. Again, like all investor-owned utilities, MGE is routinely allowed to recover the taxes it pays from its ratepayers through the inclusion of those tax payments in its cost of service when its rates are calculated in a rate case.

The Kansas property tax on gas held in storage in that state is unusual in that MGE, which does not serve customers in Kansas, has never before had to pay property tax in Kansas. However, if the Kansas taxes are found to be legal in the ongoing court challenge, and MGE is required to pay the tax, it should be able to recover those tax payments for future years through its rates when it includes those [\*40] taxes in its cost of service in a future rate case.

The problem is that, at the moment, MGE can not include the Kansas taxes in its cost of service in this rate case. As a general rule, for an item of cost to be included in a utility's cost of service, that item of cost must be both known and measurable. A utility's customers should not be expected to pay, through their rates, for costs that are speculative and

uncertain. MGE's Kansas tax liability is now *measurable* - it has received a bill from the Kansas tax authorities for the 2004 year. Future tax bills can be estimated - but its Kansas tax liability is not yet *known* because of the uncertainty resulting from the ongoing legal challenge. If MGE prevails in court, it may never have to pay the Kansas property taxes.

The amount of taxes that MGE might have to pay in Kansas is significant to both MGE and to its ratepayers. It would not be appropriate to allow MGE to recover millions of dollars from its ratepayers for taxes that it might never have to pay. On the other hand, taxes are a legitimate cost of doing business for which ratepayers should be responsible. It would not be fair to MGE's shareholders to shift that burden [\*41] on to them if those taxes ultimately must be paid. Furthermore, it was MGE's decision to challenge the legality of the Kansas taxes, a decision that could greatly benefit its ratepayers, that has placed MGE in this difficult position. If MGE had accepted the Kansas taxes without challenge, it could have simply passed the added taxes on to its ratepayers through this rate case. Instead, by looking out for the interest of its ratepayers, it has created the possibility that it will not be able to recover several million dollars to which it would otherwise be entitled. It is that conundrum that makes an AAO the appropriate means for dealing with the potential Kansas tax liability.

Having been granted an AAO, MGE may continue to defer the cost of paying the Kansas property taxes for consideration in a future rate case after the legality of those taxes is determined and the costs are both known and measurable. If those taxes are found to be illegal and MGE does not have to pay them, then the deferred amounts will simply be written off the balance sheet and neither the ratepayers nor the shareholders will be harmed. If, on the other hand, MGE ultimately must pay the taxes, it will be able [\*42] to make its case for the inclusion of its additional tax liability into its cost of service in a future rate case.

This uncertainty surrounding MGE's obligation to pay a significant amount of taxes is an unusual and unique situation that is not likely to recur. As such, it meets the Sibley standard for the granting a continued AAO, which is appropriate.

#### 14. Return on Equity

*Issue Description: What is the appropriate return on equity to use in calculating MGE's cost of service?*

Determining an appropriate return on equity is without a doubt the most difficult part of determining a rate of return. The cost of long-term debt and the cost of preferred stock are relatively easy to determine because their rate of return is specified within the instruments that create them. In contrast, determining a return on equity requires speculation about the desires and requirements of investors when they choose to invest their money in Southern Union rather than in some other investment opportunity. As a result, the Commission can not simply find a rate of return on equity that is unassailably, scientifically, mathematically, or legally correct. Such a "correct" rate does not exist. [\*43] Instead, the Commission must use its judgment to establish a rate of return on equity that will be attractive enough to investors to allow the utility to fairly compete for the investors' dollar in the capital market, without permitting an excessive rate of return on equity that would drive up rates for MGE's ratepayers. In order to obtain guidance about what rate of return on equity is appropriate, the Commission must turn to expert advice offered by financial analysts.

Three financial analysts offered recommendations regarding an appropriate return on equity in this case. MGE's witness, Frank Hanley, comparing the four cost-of-common-equity models n93 to proxies arrived at an initial return on equity of 11.5%. Hanley then argues that this return should be increased because MGE faces more risk because it is smaller than the average company in the proxy group and because it lacks protection from the vagaries of weather. In light of these added risks, Hanley increased his suggested return on equity by 45 basis points to arrive at 11.95%. n94 However, Hanley reduces this amount by 35 basis points, to 11.6%, if the SFV rate design were adopted. n95 Hanley then deducts another 10 points. [\*44] n96 Staff's witness David Murray, relying on the DCF model and testing its reasonableness using the CAPM, arrived at a recommended return on equity in the range of 8.35 - 8.95%. He then adjusted this amount upward by 30 basis points because the average bond rating for the proxy group he used was "A" and that of Southern Union is "BBB". His resulting range for return on equity was thus, 8.65 - 9.25%. n97 Public Counsel's witness, Russell Trippensee, suggests that the return on equity be in the range of 7.70% to 8.65%. Trippensee argues that risk associated with earnings variability is essentially eliminated under the SFV rate design. n98

n93 The four models are: 1) Discounted Cash Flow Model (DCF); Risk Premium Model (RPM); Capital Asset Pricing Model (CAPM); and Comparable Earnings Model (CEM).

n94 Hanley Direct, Page 74, Lines 1-4.

n95 Transcript, Page 80, Lines 10-18.

n96 Transcript, Page 80, Lines 16-18.

n97 Murray Direct, Page 37, Lines 7-23.

n98 Rebuttal Testimony, Page 1, Lines 1-6.

[\*45]

Between the three experts, there is obvious disagreement on this issue. The more varying suggestions are between MGE and OPC, which is at best a difference of 2.95%. Staff and MGE, both using the DCF model, differ at best by 2.35%. Of course the credibility of all of the experts was challenged. Trippensee's expertise was even challenged to the extent of MGE moving to strike his testimony because he had not conducted an independent evaluation but instead simply critiqued those of Staff and MGE.

The Commission's obligation under the law, and as a matter of practical necessity, is to allow Southern Union an opportunity to earn a return that will allow it to compete in the capital market. No one, including ratepayers, benefits if MGE is starved for capital.

Hanley's recommended return on equity, on behalf of MGE, was 11.5%. Staff's suggestion, at best, is 9.25%. OPC's is even lower than that offered by Staff. The Commission notes that Staff, using the DCF model arrived at a return on equity for Southern Union of 10.83 to 13.43%. n99 This range does not consider proxies for MGE but rather considers the risks specifically associated with Southern Union. Because Staff argues that the actual [\*46] capital structure of MGE should be used, Staff's recommended range of 8.65% to 9.25% is inconsistent with Staff's findings of an ROE directly associated with that capital structure.

n99 Transcript, Page 246, Lines 8-13.

OPC's recommendation holds very little weight as it did not perform any independent study on this issue. Rather, OPC seemed to have simply looked to Staff's recommendation and opined that Staff and MGE's recommendations do not reflect a reduction in risk associated with the SFV rate design. n100 It doesn't appear that OPC recognizes that at least one of Staff's proxy companies had a SFV rate design. All of the companies had some sort of revenue decoupling rate design. Additionally, although MGE's residential class comprises 90% of its customer base, only 65% of the company's revenue is from its residential customers. n101 MGE's small commercial class, alone, accounts for \$ 35-40 million. n102

n100 Trippensee Rebuttal, Page 12, Lines 1-6.

[\*47]

n101 Transcript, Page 176, Lines 21-25

n102 Transcript, Page 177, Lines 12-15.

MGE's witness uses four cost-of-common-equity models to arrive at his eventual recommendation of 11.5%. n103 MGE's results of the Discounted Cash Flow, Risk Premium and Capital Asset Pricing models are 10.43%, 10.53% and

10.44%, respectively. The average of those is 10.47%. However, when averaged with Comparable Earnings Model, resulting in a 14.25% ROE, this average goes to 11.41%. The Commission finds that the Comparable Earnings model result, almost 400-points different than the other 3 models, is not credible and should be excluded. Additionally, Mr. Hanley supplied the Commission with a list of authorized returns on common equity for gas companies with an average ROE of 10.53. n104 This is consistent with the resulting average of the three models discussed above.

n103 Hanley Direct, Schedule FJH-1.

n104 Hanley Direct, Schedule FJH-17.

[\*48]

From his original recommendation of 11.5% Mr. Hanley makes upward adjustments of 30 and 15 basis points due to MGE's size and its lack of protection from weather. To account for an SFV rate design for MGE, he makes a downward adjustment of 35 points to arrive at 11.6 and recommends 11.5. What is interesting about this downward adjustment is that it only reduces the ROE by 20 points. An SFV rate design protects the company from the vagaries of weather. Mr. Hanley first added 15 points for a lack of protection and then deducted 35 for such protection.

All of the parties agree that a determination of ROE is a complicated judgment call. The Commission is persuaded by Staff's conclusion of an ROE of 10.83 - 13.43%. This range is based on a recommended ROE for Southern Union, not an LDC standing alone. The Commission has found that the actual capital structure of Southern Union shall be used. Staff's conclusion is consistent with this finding. Because there must be consideration of the SFV rate design afforded MGE, the Commission will adopt the low end, 10.83%, of Staff's conclusion. Also, under Staff's DCF model, 10.83% is the projected cost of common equity. n105 This is where the Commission [\*49] will start. Staff and MGE agree that the value of the SFV rate design is 30-35 basis points. As these suggestions are estimates, the Commission finds that the value of the SFV rate design is 32.5 points. A reduction of .325 from 10.83 results in a ROE of 10.5%. The Commission finds that MGE's return on equity shall be 10.5%, which is validated by the conclusions of the cost models, used by MGE and Staff, discussed above.

n105 Murray Direct, Schedule 18.

## CONCLUSIONS OF LAW

The Missouri Public Service Commission has reached the following conclusions of law.

MGE is a public utility, and a gas corporation, as those terms are defined in *Section 386.020(42)* and (18), RSMo 2000. As such, MGE is subject to the Commission's jurisdiction pursuant to Chapters 386 and 393, RSMo.

*Section 393.140 (11)*, RSMo 2000, gives the Commission the authority to regulate the rates that MGE may charge its customers for natural gas. When MGE filed a tariff [\*50] designed to increase its rates, the Commission exercised its authority under *Section 393.150, RSMo 2000*, to suspend the effective date of that tariff for 120 days beyond the effective date of tariff, plus an additional six months.

In determining the rates that MGE may charge its customers, the Commission is required to determine that the proposed rate is just and reasonable. n106 MGE has the burden of proving that its proposed increase is just and reasonable. n107

n106 *Section 393.150.2 RSMo 2000.*

n107 *Section 393.150.2, RSMo 2000.*

### Unrecovered Cost of Service Amortization

All parties to this matter agree that to allow MGE to amortize this expense would constitute retroactive ratemaking. A well worded, although colloquial definition, is set out by Staff's witness Oligschlaeger as:

the setting of rates to allow a utility to recover the specific costs of past events incurred by [\*51] the utility so as to make utility shareholders "whole" or, conversely, it is the setting of rates to reimburse customers related to past over-earnings of a utility so as to make the customers "whole" n108

n108 Oligschlaeger Rebuttal, Page, 4, Lines 6-10.

In light of the fact that all parties agree that to allow this cost to be amortized and included in current rates would constitute retroactive ratemaking, the Commission's conclusion must be consistent with that of all of the parties. Concluding that it would constitute retroactive ratemaking, the Commission will not allow MGE's request to amortize this lost.

### Property Tax Refund

MGE argues that to amortize this refund and include it in current rates would constitute retroactive ratemaking. MGE points out that if the Commission allows Staff's request in this regard, it must also allow MGE's request under the issue of Unrecovered Cost of Service Amortization. Staff's reason for arguing that its request would not constitute retroactive ratemaking is that the [\*52] money was received during the test year.

MGE's position assumes that Staff's request would constitute retroactive ratemaking. Then, in comparing this issue with Unrecovered Cost of Service, MGE argues that if the Commission adopts Staff's position on this issue it must adopt MGE's position under the previous issue. This argument simply begs the question of whether the Commission will allow retroactive ratemaking. Staff's position hinges on the test year.

The Commission will not adopt a position that would constitute retroactive ratemaking. As pointed out by MGE, "retroactive ratemaking is the setting of rates which permit a utility to recover past excess losses of which require it to refund past excess profit collected under at ate that did no perfectly match expenses plus rate-of-return with the rate actually established." n109 The same case goes on to hold that these past occurrences may be considered insofar as it is necessary to determine what a just and reasonable rate would be going forward.

n109 *State ex rel. Utility Consumers Council of Missouri, Inc. v. Public Service Commission*, 585 S.W.2d 41 (1979).

[\*53]

Like the issue of Unrecovered Cost of Service, the Commission concludes that to adopt Staff's request in this regard would constitute retroactive ratemaking.

### Infinium Software

OPC argues that the system is not used and useful and opposes MGE's proposal. In this regard, OPC refers to *State ex rel. Union Electric v. P.S.C.*, 765 S.W.2d 618 (Mo. App. 1988) in its post hearing brief. That case states that:

The property upon which a rate of return can be earned must be utilized to provide service to its customers. That is, it must be used and useful. This used and useful concept provides a well-defined standard for determining what properties if a utility can be included in rate base.

However, MGE made an adjustment to remove the plant investment in the software out of its rate base, which means MGE will not earn a return on the plant. With the concept of "use and useful" being the premise of OPC's opposition, its argument must be rejected. Both Staff and MGE point out that the plant is not included in rate base. Therefore, the company will not earn a return on the property. The Commission concludes that the concept of "used and useful" then becomes [\*54] irrelevant and will allow continued amortization of the software as proposed by MGE and Staff.

## DECISION

After its findings of fact and conclusions of law, the Commission has reached the following decision regard the issues as identified by the parties.

### 1. Capital Structure

*Issue Description: What is the appropriate capital structure (i.e. the relative proportions of long-term debt, short-term debt, preferred equity, and common equity) to use in calculating MGE's cost of service?*

Common Equity	36.06%
Long-Term debt	55.92%
Preferred Stock	4.71%
Short-Term Debt	3.3%

### 2. Rate Design

*Issue Description: What is the appropriate rate design for residential, small general service, large volume service and large general service classes?*

The rate design for the residential class shall be the Straight-Fixed Variable Design proposed by Staff. To the extent that they are consistent with the Stipulation and Agreement regarding class cost of service, the current rate designs shall remain in effect for all non-residential classes.

### 3. Unrecovered Cost of Service Amortization

*Issue Description: Should MGE recover \$15.6 million in rates [\*55] amortized over five years for alleged revenue loss due to lower customer gas use for the period of January through June of 2006?*

No. The Commission rejects MGE's proposal on this issue.

### 4. Property Tax Refund.

*Issue Description: What is the proper treatment of \$ 5,554,068 in property tax refunds received by MGE during the test year of 2005?*

The Commission denies Staff proposal to amortize this refund. MGE will be allowed to keep this money as a gain.

### 5. Weather Normalization

*Issue Description: What is the appropriate measure of normal weather to be used in calculating 1) MGE's revenue requirement and 2) the billing determinants to be used in establishing MGE's volumetric rates?*

The Commission adopts Staff position that the 30-year normal will be used and rejects MGE's proposal that a 10-year rolling average should be implemented.



## 6. Low Income Weatherization

*Issue Description: What is the appropriate level of low-income weatherization funding to be used in calculating MGE's cost of service and how should such funding be allocated among the geographical regions of MGE's service territory?*

The Commission adopts the City of Kansas [\*56] City's proposal to allocate \$ 250,000 to the Low-Income Weatherization program.

## 7. Natural Gas Conservation

*Issue Description: Should funding for natural gas conservation programs be included in MGE's cost of service?*

Yes. The Commission adopts Staff and MGE's proposal to allocate \$ 705,000 for a water heater rebate program and \$ 45,000 for educating MGE's customers about weather conservation.

## 8. Environmental Response Fund

*Issue Description: Should the environmental response fund proposed by MGE be adopted and what, if any, level of environmental costs should be used in calculating MGE's cost of service? MGE requests that the amount of the fund be \$ 500,000, annually.*

The Commission rejects the Environmental Response Fund proposed by MGE.

## 9. Infinium Software

*Issue Description: Should the unrecovered cost associated with MGE's Infinium Software be included in rates through an amortization and, if so, over what period of time?*

The Unrecovered cost associated with MGE's Infinium Software should be included in rates and amortized over 5 years as proposed by Staff and OPC.

## 10. Rate Case Expense

*Issue Description: What [\*57] is the appropriate amount and treatment of rate case expense, including amortization of prior rate case expense, in this case?*

MGE shall be allowed to amortize the combined amounts over a three-year period.

## 11. Emergency Cold Weather Rule AAO Recovery

*Issue Description: What is the proper rate treatment for costs deferred under the Emergency Cold Weather Rule AAO Recovery Mechanism?*

The Commission will grant MGE's request to amortize the deferred cost through an AAO.

## 12. Seasonal Disconnects<sup>4=R</sup>

*Issue Description: Should the seasonal disconnect tariff language proposed by MGE be approved?*

No.

## 13. Kansas Property Tax AAO

*Issue Description: Should the Kansas Property Tax AAO be continued past the expiration date ordered by the Commission in Case No. GU-2005-0095?*

MGE is allowed to continue the Kansas Property Tax AAO beyond the date ordered in Commission Case No. GU-2005-0095 until a final determination is made on this issue by the Kansas courts.

#### **14. Return on Equity**

*Issue Description: What is the appropriate return on equity to use in calculating MGE's cost of service?*

The appropriate return on equity is 10.5%. [\*58]

#### **IT IS ORDERED THAT:**

1. The tariff sheets filed by Missouri Gas Energy, a division of Southern Union Company, on May 1, 2006, and assigned tariff number YG-2006-0845, are rejected.
2. Missouri Gas Energy, a division of Southern Union Company, is authorized to file a tariff sufficient to recover the revenues as determined by the Commission in this order.
3. This Report and Order shall become effective on March 30, 2007.

#### **BY THE COMMISSION**

Davis, Chm., Murray, and Appling, CC., concur; Gaw, C., dissents, with separate dissenting opinion to follow; Clayton, C., dissents; and certify compliance with the provisions of *Section 536.080, RSMo.*

Dated at Jefferson City, Missouri, on this 22nd day of March, 2007.

2007 Mo. PSC LEXIS 278, \*

In the Matter of Atmos Energy Corporation's Tariff Revision Designed to Consolidate Rates and Implement a General Rate Increase for Natural Gas Service in the Missouri Service Area of Atmos

Case No. GR-2006-0387; Tariff No. YG-2006-0762

PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

*2007 Mo. PSC LEXIS 278*

February 22, 2007, Issued; March 4, 2007, Effective

**SYLLABUS:**

[\*1] This order rejects the general rate increase originally requested by Atmos Energy Corporation. The order also authorizes Atmos to file new tariff sheets in compliance with this order. If Atmos files new tariff sheets with the new fixed monthly charge rate design, it shall also implement an efficiency and conservation program as set out herein. Otherwise, the Commission finds that Atmos shall maintain its current rate structure with no additional revenue required.

APPEARANCES: James M. Fischer and Larry W. Dority, Fischer & Dority, P.C., 101 Madison Street, Suite 400, Jefferson City, Missouri 65101, for Atmos Energy Corporation; Douglas C. Walther, Associate General Counsel, Atmos Energy Corporation, Post Office Box 650205, Dallas, Texas 75265-0205, for Atmos Energy Corporation; David Woodsmall, Finnegan, Conrad & Peterson, 428 East Capitol Avenue, Suite 300, Jefferson City, Missouri 65101, for Hannibal Regional Hospital; Robin E. Fulton, Schnapp, Fulton, Fall, Silvey & Reid, L.L.C., 135 East Main Street, Fredericktown, Missouri 63645, for Noranda Aluminum, Inc.; Marc D. Poston, Senior Public Counsel, Office of the Public Counsel, Post Office Box 2230, Jefferson City, Missouri 65102, [\*2] for the Office of the Public Counsel and the public; Kevin A. Thompson, General Counsel, Lera L. Shemwell, Senior Counsel, and Robert S. Berlin, Associate General Counsel, Missouri Public Service Commission, Post Office Box 360, Jefferson City, Missouri 65102, for the Staff of the Missouri Public Service Commission.

PANEL: Davis, Chm; Appling, C., concur; Murray, C., concurs; Gaw; Clayton, CC., dissent; Nancy Dippell, Deputy Chief Regulatory Law Judge

**OPINION: REPORT AND ORDER**

**Findings of Fact**

The Missouri Public Service Commission, having considered all of the competent and substantial evidence upon the whole record, makes the following findings of fact. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision.

**Procedural History**

On April 7, 2006, Atmos filed revised tariff sheets which set forth revised rate schedules and certain revised charges for all of Atmos' service [\*3] territories in the state of Missouri, designed to produce an increase of approximately \$ 3.4 million in new revenues for Atmos. The new rate schedules would increase revenues to provide an overall rate of return on rate base of 8.59 percent on the test year rate base of \$ 56.0 million. n1

n1 Ex. 1, pp. 5-6, 10-11.

Atmos is the largest pure natural gas distribution company in the United States, with corporate offices located in Dallas, Texas. Atmos is comprised of six gas utility operating divisions, and its Mid-States Division (located in Frank-

lin, Tennessee) provides natural gas distribution service in Missouri, Tennessee, Virginia, Georgia, Kentucky, Illinois and Iowa. Regional and state offices for the Missouri operations are located in Hannibal, Jackson and Sikeston. Atmos serves approximately 60,000 customers in Missouri, and the customer base includes residential, commercial and industrial customers. Employing a Missouri-based work force of approximately 75 employees, Atmos' utility plant in Missouri includes [\*4] over 2,150 miles of transmission and distribution lines. n2

n2 Ex. 1, pp. 4-5, 10.

Atmos' Missouri operations are comprised of six base rate areas located in the northeast, southeast and west-central areas of Missouri, and are the result of the following acquisitions: Greeley Gas Company purchased in 1993; United Cities Gas Company purchased in 1997; and Associated Natural Gas Company purchased in 2000. n3

n3 Ex. 1, p. 3; Ex. 110, pp. 1-2.

Atmos had not filed for a rate case since acquiring these Missouri service areas, so the rates for each district were set when the preceding LDC had its last rate case. United Cities filed its last rate request in Missouri in 1994, and rates were approved and implemented in 1995. The last rate increase affecting the utility properties Atmos acquired from ANG was filed, approved and implemented in 1997. n4

n4 Ex. 1, p. 5; Ex. 110, p. 3.

[\*5]

A "Joint Issues List, List of Witnesses and Order of Cross-Examination" was filed by the Staff of the Commission on behalf of the parties, on November 14, 2006. As set forth in the "Joint List of Issues," the parties identified the following issues as being resolved:

1. Billing Determinants
2. Research and Development Rider
3. Noranda (all issues)
4. Class share of revenue by district
5. Uncollectibles in the PGA
6. Customer Service Issues
7. Class Cost of Service

In addition, local public hearings, a rate design technical conference, a settlement conference and evidentiary hearings were held in this matter. The parties each submitted prehearing and post hearing briefs, or a statement declining to do so. The post hearing briefs were submitted on January 19, 2007.

On December 12, 2006, the second part of Exhibit 144 was filed by Staff. No objection to the exhibit was received, and it is hereby admitted into evidence.

#### **The Partial Stipulation and Agreement**

In addition to the issues identified as being resolved in the Joint Issues List of November 14, 2006, Atmos, Staff and the Office of the Public Counsel submitted their Partial Non-Unanimous Stipulation and Agreement to the [\*6] Commission for approval on November 29, 2006. The Agreement sets forth additional issues settled among those par-

ties. Staff filed its memorandum in support of the Agreement on December 12, 2006. No party opposed the Agreement. Therefore, as permitted by Commission Rule 4 CSR 240-2.115, the Commission shall treat the Agreement, attached to this Report and Order as Attachment A, as if it were unanimous. The Commission finds the Agreement just and reasonable and, therefore, approves it. In its discussion of the issues as set forth by the parties, the Commission will identify and address those specific components that have been resolved pursuant to the Agreement.

### The Issues

1. What is the appropriate revenue requirement?
  - a. What is the appropriate level of expense?
  - b. What is the appropriate rate of return / return on equity?
  - c. What is the appropriate level of revenue excess/deficiency?

Rate-making involves two successive processes. First is the determination of the revenue requirement; the amount of revenue the utility must receive to pay the costs of producing utility service while yielding a reasonable rate of [\*7] return to the investors.<sup>n5</sup> The second process is rate design, the construction of tariffs that will collect the necessary revenue requirement from the ratepayers.

<sup>n5</sup> *St. ex rel. Capital City Water Co. v. Missouri Pub. Serv. Comm'n*, 850 S.W.2d 903, 916 n 1 (Mo. App., W.D. 1993).

Atmos' gross annualized revenue of \$ 16,507,737 was stipulated to in the Partial Non-Unanimous Stipulation and Agreement. Atmos' revised tariff sheets as originally proposed would have increased revenues to provide an overall rate of return on rate base of 8.59 percent on the test year rate base of \$ 56.0 million. The original proposal also contained a weather mitigation adjustment in the rates. Atmos' requested return on common equity (ROE) in this case was 12 percent. <sup>n6</sup>

<sup>n6</sup> Ex. 14, pp. 29-31.

Staff initially calculated a \$ 1.2 million revenue [\*8] excess. Staff is not seeking a revenue reduction or filing an excess earnings complaint. After evaluating the positions of the parties (a difference of \$ 4.4 million), Staff believed there was a significant chance that it would not prevail in its entire revenue reduction. Furthermore, if Staff failed to prevail on all its issues, Staff believed that Atmos might end up with a revenue increase. <sup>n7</sup> And, given that ROE was an issue worth \$ 1 million, Staff believed the Commission might easily determine that a zero revenue requirement or even a positive change was necessary. Thus, it is Staff's opinion that a zero change in cost of service on a total company basis will still result in just and reasonable rates. <sup>n8</sup> Instead of a revenue reduction, Staff is now advocating a change from Atmos' current rate design, to a fixed monthly delivery charge for non-gas costs.

<sup>n7</sup> Ex. 104, pp. 1-2; Tr. 99-102, 106-107.

<sup>n8</sup> Ex. 104, p. 2.

Staff originally proposed a ROE of 8.59 percent to 9.39 percent. Because Staff has advocated [\*9] a zero change in revenue requirement with a new rate design, Staff no longer advocates a particular ROE. Instead, Staff recommends the revenues stay the same.

After reviewing Staff's proposed new rate design, Atmos abandoned its rate increase proposal and is advocating adopting Staff's fixed monthly delivery charge rate design with the slight modification of "sculpting" rates so that the summer charge is less than the winter charge while overall annual revenues stay the same. n9

n9 Ex. 6, p. 3; Ex. 7, p. 2.

Public Counsel recommends that the Commission find that rates should be reduced n10 based upon the initial revenue requirement position of the Staff. Public Counsel did not file any direct testimony in this case regarding the overall revenue requirement. Public Counsel also has not filed a complaint against the reasonableness of Atmos' existing rates. n11

n10 Tr. 626-627.

n11 Tr. 557.

**[\*10]**

The Commission finds, based on the evidence regarding rate of return and the positions of the parties, that regardless of the rate design, no change in cost of service, on a total company basis, is necessary to produce just and reasonable rates. As a result, the Commission finds that the answer to subpart c of this issue -- What is the appropriate level of revenue excess/deficiency? -- is zero. Having made this determination, the first two subparts of this issue (a. What is the appropriate level of expense? and b. What is the appropriate rate of return/return on equity?) are rendered moot. Nevertheless, the Commission will address Public Counsel's position on these issues.

Public Counsel's witness, Mr. Trippensee, sponsored cost of common equity rebuttal testimony suggesting that the Commission use a seven percent ROE in this proceeding if Staff's rate design proposal is adopted. Public Counsel believes this reduction in ROE is necessary to offset the corresponding elimination of weather variability and other business risk for Atmos. Mr. Trippensee attempted to quantify the risk reduction that he believed was associated with the fixed delivery charge rate design. n12 However, as explained [\*11] further below, the seven percent ROE was calculated using a methodology which is very problematic and is not a method typically relied on by experts in the field. n13

n12 Ex. 203, p. 11.

n13 Tr. 179-180.

Both Atmos and Staff's witnesses on this issue, Dr. Donald A. Murry and Mr. Matthew Barnes, thoroughly rebutted Mr. Trippensee's proposal and established that such recommendation was not supported by any commonly accepted rate of return analysis. n14 Mr. Trippensee was also unable to offer any authority in support of his methodology, which Dr. Murry described as "just unorthodox opinion." n15 Furthermore, Mr. Trippensee "did not analyze the cost of common equity of companies that may have similar risk characteristics as those that may be in effect for Atmos' Missouri operations" n16 and "did not even recognize that many of [Staff's] . . . comparable companies have weather mitigation rate designs that minimize risks related to changes in the weather." n17

n14 Ex. 15, Ex. 102.

**[\*12]**

n15 Ex. 15, p. 3.

n16 Ex. 102, p. 2.

n17 Ex. 102, p. 2.

As Dr. Murry explained in detail in his Surrebuttal Testimony and on the witness stand, contrary to the criticism that Staff's analysis does not consider the decreased business risk associated with its proposed rate design, seven of the eight companies that Mr. Barnes identified as comparable to Atmos operate under some type of revenue stabilization mechanisms for their residential and small commercial customers. n18 In addition, Mr. Barnes confirmed that there was no need for further reduction in his recommended ROE because risk is already reflected in his comparable group analysis. n19 The evidence also revealed that Atlanta Gas and Light, one of the comparable companies, has a rate design similar to what Staff is proposing in this case. That company has been authorized a 10.9 percent return on equity. n20 Mr. Barnes further testified that Staff proposed a "range" of ROEs in this case, as it typically does, which covers a variety of risks affecting the companies. n21

n18 Ex. 15, pp. 4-6; Tr. 89-90.

[\*13]

n19 Tr. 598.

n20 Tr. 512, 592.

n21 Tr. 610-611.

The Commission finds that Mr. Barnes' analysis of comparable companies includes some degree of risk reduction based on the fact that most of the companies have weather mitigation elements. While Mr. Trippensee had some valid arguments about the need for risk to be considered, his proposed ROE was not reasonable and the Commission finds his methodology to be unreliable.

Based on all the foregoing evidence, the Commission finds that there is zero net additional revenue requirement necessary in order for Atmos to achieve its stipulated gross annualized revenue of \$ 16,507,737. The Commission finds that rates designed to produce a zero net revenue increase are just and reasonable in that they meet Atmos' prudent operating expenses and, based on the analysis of Staff of comparable companies, allow an opportunity to earn a reasonable return on the value of the private property dedicated to public service.

This finding that no change in revenue requirement is necessary does not mean, however, that the Commission accepts Staff and Atmos' fixed [\*14] delivery charge rate design proposal *carte blanche*. Rather, as will be explained below, the Commission has determined that a fixed delivery charge is not acceptable without a substantial energy efficiency and conservation program.

## **2. What is the appropriate treatment of depreciation and should depreciation expense be reduced by a depreciation reserve amortization?**

### **Record Keeping and Reporting**

Depreciation Record Keeping and Reporting has been settled in accordance with the Partial Non-Unanimous Stipulation and Agreement. n22

n22 Section VI, page 5 and Attachment B.

### Depreciation Reserve Amortization

Staff and Atmos have proposed a negative amortization of the depreciation reserve in the amount of \$ 591,000. n23 This approach would be implemented by entering a negative amortization of \$ 591,000 into the depreciation reserve account 108. This would provide an immediate benefit to Atmos' customers by lowering Atmos' depreciation expense to a level that Staff believes is appropriate.

n23 Tr. 188.

[\*15]

Public Counsel objects to this negative amortization based on Atmos providing insufficient data for the Staff to perform an accurate depreciation analysis. n24 Public Counsel also objects because it argues that the negative amortization will require Atmos to reinvest moneys already paid by ratepayers in order to reduce current rates, and will require the customers to pay a return "on and of" these amounts in future rates. n25

n24 Ex. 107, p. 8.

n25 Ex. 203, p. 13.

Staff's witness, Mr. Gilbert, testified that he was unable to verify the accuracy of Atmos' data and records and "accepted [Atmos] management's recognition and acknowledgment of an over-accrual of depreciation." n26 Mr. Gilbert admitted that future ratepayers would be required to repay the \$ 591,000, n27 but testified that ratepayers would pay less with the negative amortization than they would pay in rates with different depreciation rates. Mr. Gilbert gave the following example:

[I]f we were to use an example of 10 percent for the return on [\*16] equity for that additional \$ 591,000 of rate base, it would cost ...[the ratepayers] \$ 59,100 a year as opposed to savings of \$ 591,000 a year in depreciation expense. So, the difference of those two would be the net savings to the current ratepayers. n28

n26 Tr. 188-189.

n27 Tr. 200-201.

n28 Tr. 200.

Although there might be different methods of achieving the same goal, with the negative amortization, future rates to customers will be less than if the \$ 591,000 was reflected in lower depreciation rates. n29 This method of amortization has often been used by both Staff and other utility companies to offset depreciation over and under-accruals in reserve account 108. In this instance, the amortization would offset an over-accrual to the depreciation reserve.

n29 Tr. 200.



The Commission finds that, as a whole, the annual depreciation accrual [\*17] should be reduced by approximately \$ 591,000. The Commission further finds that entering a negative amortization of \$ 591,000 to the depreciation reserve account provides an immediate benefit to Atmos' customers by lowering Atmos' depreciation expense. The Commission finds that the benefits of the negative amortization outweigh any potential harm and that the negative amortization is therefore just and reasonable.

**3. What is the appropriate rate design?**

**a. What is the appropriate rate structure for residential, small, and medium general service?**

**b. What is the appropriate structure for the small general service rate (including the medium general service rate if the small general service class is split)?**

**Rate Design**

Atmos currently has a "traditional" residential base rate design consisting of a customer charge and a volumetric rate. Under the traditional rate design, residential non-gas margin costs are collected using both a monthly customer charge, which does not vary with usage, and a volumetric charge levied on each Ccf consumed. n30 Non-gas margin costs make up only a portion of a residential customer's total monthly bill. The actual gas cost portion [\*18] of the bill, called the purchased gas adjustment or PGA, makes up the rest. For the average customer, this is about 80 percent of the total. n31

n30 Tr. 317.

n31 Tr. 78.

In the current case, Staff has proposed a shift from the traditional two-part base rate design to a design in which all non-gas costs are recovered in one fixed monthly charge. This type of fixed delivery charge is often termed a "straight fixed variable" rate design. n32

n32 Tr. 694-695; Tr. 85.

For residential and small general service classes Staff recommends recovering the entire amount of the non-gas, or margin, costs in a fixed monthly delivery charge. n33 Staff believes this proposed rate structure will address two significant current issues affecting the natural gas distribution market: 1) remove disincentives for utilities to encourage and assist customers in making [\*19] conservation and efficiency investments; and 2) reduce the effects of weather on utility revenues and customer bills. n34

n33 Ex. 110, p. 9.

n34 Ex. 110, pp. 9-10.

Under Staff's proposal, each of Atmos' three service areas, Western Missouri (WEMO), Northeast (NEMO), and Southeast (SEMO), would have a unique fixed delivery charge that is based, per the Agreement, on the revenues generated by the current residential customers within that geographic service area. n35 Staff's proposed fixed monthly delivery charges are as follows: n36

SEMO (includes Neelyville)	\$ 13.92 / month
WEMO (Butler and Greeley)	\$ 19.43 / month

NEMO (Kirksville; Palmyra; Hannibal; Canton;  
Bowling Green)

\$ 20.61 / month

Staff argues that maintaining the "status quo" rate structure:

1. forces Residential customers whose usage is greater than the average to pay more than the cost required to serve them, while allowing smaller customers to underpay their cost-of-service;
2. discriminates between identical Residential customers [\*20] in contiguous districts by charging different non-gas margin rates;
3. creates unnecessary volatility in customer bills by collecting a larger portion of customers' cost-of-service in the winter;
4. provides no incentive for utilities' to aggressively promote customer efficiency and conservation to their customers; and a utility doing so would be acting contrary to its shareholder interests;
5. sends incorrect price signals to Residential customers; and
6. does nothing to address Senate Bill 179. n37

n35 Staff Witness Tom Imhoff performed the Class Cost of Service study (Imhoff Direct p. 3-8). The parties agreed to no revenue shifts among the classes and to billing determinants (Attachment A, representing the weather-normalized class test year revenues) in the Partial Non-Unanimous Stipulation and Agreement filed November 29, 2006.

n36 Ex. 137; Ex. 7, Schedule PJC SURREB 1.

n37 Ex. 111, p. 6.

Atmos' original rate design proposal embodied a weather normalization adjustment. However, Atmos' witnesses [\*21] testified that after careful consideration of the Staff's rate design proposal, Atmos supports the adoption of the Staff's rate design recommendations in lieu of the weather normalization adjustment.

As Staff's witness, Ms. Ross, testified, there is a "rapidly-changing environment" with regard to natural gas distribution. n38 Ms. Ross explained that "[a]pproximately five years ago, natural gas prices increased dramatically, and did not return to their previous levels." n39 This increase in prices caused residential customer bills to double. In addition, the non-gas portion of a customer's bill went from being approximately 60 percent of the total monthly bill to being approximately 20-25 percent of the total monthly bill. n40

n38 Ex. 111, p. 5.

n39 *Id.*

n40 *Id.*

In addressing the fixed delivery charge rate design proposal, Ms. Ross explained that the Staff rationale has changed over the years. And, that on a national basis, there has been much discussion about conservation and "decoupling," or separating [\*22] the delivery costs from the volumetric costs. n41 Ms. Ross specifically references a Novem-

ber 2005, National Association of Regulatory Utility Commissioners (NARUC) *Resolution on Energy Efficiency and Innovative Rate Design*. n42 That resolution calls for state commissions and other policy makers to consider new rate designs that will encourage energy conservation and energy efficiency.

n41 Tr. 448, 453.

n42 Ex. 110, Schedule 3-1.

Public Counsel opposes Staff's rate design proposal and advocates maintaining the status quo. Public Counsel argues that the fixed delivery charge rate design is harmful to consumers because: (1) the effect of the proposal is truly not known without sufficient studies; (2) customer efforts to conserve energy will be negated; (3) no conservation or efficiency programs have been introduced; and (4) it will be contrary to good public policy in that it will shift a substantial portion of the cost to the lowest use customers. n43

n43 Tr. 57-58.

[\*23]

The Commission has set natural gas rates as a two-part base rate for many years and found those rates to be just and reasonable. There is no way of knowing 100 percent of the effects a fixed rate design will have on the ratepayers without having actually experienced such a design. However, the Commission finds the decision by Atmos to abandon its request for a \$ 3.4 million revenue increase in its entirety is sufficient reason to overcome any doubts about the proposed rate design. Especially when considering that even a portion of that revenue increase, if found just and reasonable, could have a traumatic effect when spread out over the approximately 60,000 customers served by Atmos. The Commission further finds that such a rate design is worthwhile so long as it is accompanied by an energy conservation program.

The current rates are designed with a conservation incentive "built in" in that the less gas a customer uses the less that customer will pay. The current rate design encourages conservation by increasing the minimum monthly bill paid by the customer. The rationale is that customers will notice a change in their fixed monthly bill charge and adjust their behavior appropriately. [\*24] Requiring the company to initiate a conservation program is further insurance that the fixed delivery charge rate design will promote conservation. Thus, in order to change the rate structure, the Commission finds that a conservation program of significant size would be necessary to offset any loss of traditional rate design conservation incentive.

The evidentiary record rebuts Public Counsel's second argument. Under Staff's rate design, customer efforts to conserve energy will not be negated. Eighty percent of a customer's total bill is purchased gas cost. n44 Even under Staff's proposed rate design where the volumetric portion of non-gas cost is removed in favor of a fixed delivery charge, the customer is still going to have a great incentive to reduce consumption in order to reduce 80 percent of that customer's bill. Thus, consumption is going to be largely driven by the wholesale cost of gas. In addition, by removing the disincentive that Atmos has for encouraging consumption, there is the potential for even greater conservation and efficiency to occur through a comprehensive program funded by the company.

n44 Tr. 68-69.

[\*25]

Public Counsel next argues that no conservation or efficiency programs have been introduced. Public Counsel's argument is not accurate. It would be more accurate to say that Atmos has not introduced a sufficient program. With the change in rate design, Atmos has committed to spend \$ 78,000 for low income weatherization (\$ 2,600 per household for 30 customers) and has agreed to institute a residential efficiency audit program for all residential customers (ap-

proximately 50,000) -- not just low-income customers. n45 The audit program will cost the customer \$ 25, and Atmos will pay the additional cost of the estimated \$ 60 to \$ 100 total cost per audit. n46 Atmos witness, Patricia Childers, also testified that Atmos will participate in collaborative meetings with Staff and Public Counsel to provide any further "details" that may be necessary. n47

n45 Tr. 344, 347; Ex. 7, p. 6.

n46 Tr. 348.

n47 Ex. 7, p. 6; Tr. 494.

Public Counsel did not come forward in this proceeding with any weatherization or efficiency [\*26] proposals that could assist in encouraging energy conservation or efficiency. Further, Ms. Meisenheimer makes it clear that no conservation proposals would be presented by Public Counsel in connection with the Staff's rate design proposal. n48 Ms. Meisenheimer also testified that she could not support any fixed delivery charge that recovered 100 percent of the non-gas cost. n49 Ms. Meisenheimer did state, however, that she agreed that this type of rate design could be just the "carrot" to involve companies in energy conservation programs. n50

n48 Tr. 549.

n49 Tr. 480-481.

n50 Tr. 545-546.

Finally, Public Counsel asserted that the delivery charge proposal will be contrary to good public policy in that it will shift a substantial portion of the cost to the lowest use customers. The customer demographics for Atmos regarding average residential annual Ccf usage, along with the annual Ccf consumption for various typical residential end-uses, is depicted on Staff Exhibit 142. Exhibit 142 shows that space heating [\*27] is the major area of consumption at 640 Ccf annually. The next largest area of consumption is water heating at 288 Ccf, gas fireplace inserts at 84 Ccf, and then gas cooking stoves at 24 Ccf. n51 However, the evidence shows that currently the low-use customer is being subsidized. n52 For example, Ms. Ross testified that a customer who uses gas only for cooking will have the same equipment (meters and pipes) as a customer using natural gas for space heating, heating water, and cooking. n53 The Commission finds that the cost of serving a residential customer is the same regardless of the customer's usage. So, under the status quo, customers using less than the average will underpay their cost-of-service, while customers using more than the average will overpay their cost-of-service. Staff's fixed delivery charge rate design provides a "carrot" (revenue stabilization) to get Atmos involved in energy conservation programs. However, in this case the Commission does not find sufficient resources of the company being dedicated to replacing the lost incentives for conservation provided by the traditional rate design. Atmos must give consideration for the decreased risk that it will have under [\*28] a rate design which completely eliminates weather volatility. Atmos has done that by forgoing its request for an additional \$ 3.4 million. And, Staff's comparable companies include some elements of risk within the analysis. However, that is not enough.

n51 Tr. 36-37.

n52 Tr. 304-305

n53 Tr. 355-356.

The proposed fixed monthly rate design will eliminate the inherent conflict between the shareholders (whose returns increase if more gas is sold) and the ratepayers (who will only pay less by using less). Thus, the potential for a significant program is there. The Commission also acknowledges the pledge of a \$ 78,000 low-income weatherization and the unlimited \$ 25 energy audits that the shareholders are willing to provide as a step in the right direction. However, there was no evidence to suggest that these measures will be sufficient and no details were presented as to how the programs would be implemented. The Commission cannot find that Atmos and Staff have shown that the fixed delivery charge rate design [\*29] as presented will encourage efficiency and conservation.

As Public Counsel points out, based on the specific facts of other cases, the Commission has previously determined that "[h]igh fixed monthly customer charges tend to defeat customer efforts to reduce their bill by conserving natural gas. As a result, . . . the public interest is best served by setting customer charges as low as reasonably possible." n54 However, the natural gas distribution business has changed drastically in less than a decade. It continues to evolve and as such, the Commission must be able to recognize an opportunity to evolve as well. And, as the NARUC resolution states, there is a need for state commissions to do more to promote reduced energy demand and consumption. The Commission is also aware of other programs implemented by other Missouri companies referred to in this proceeding and in other states as evidenced by the information provided in Exhibit 144. The Commission finds that a comprehensive energy efficiency and conservation program can work to provide benefits to the ratepayers and to the general public interest by reducing the demand and consumption of natural gas.

n54 Report and Order, *In the Matter of Missouri Gas Energy's Tariffs to Implement a General Rate Increase for Natural Gas Service*, Case No. GR-2004-0209, September 21, 2004.

[\*30]

The Commission finds that under the circumstances of this case, Atmos' rates are ripe for being redesigned. However, the Commission cannot find such a design to be in the public interest without some assurance of a significant energy conservation and efficiency program that will educate and assist Atmos' customers in conservation and reduced demand. In this instance the Commission has determined that with the right conservation and efficiency program, a fixed delivery charge would be in the public interest while allowing Atmos a fair return on its investment.

Atmos has proposed \$ 78,000 and unlimited energy audits creating a minimum of \$ 1.75 million n55 worth of potential liability. Obviously, not every one of the 50,000 residential customers served by Atmos will request an audit. However, that commitment shows that Atmos is capable and willing to provide enough funding to implement a meaningful conservation program. Thus, the Commission finds that it would be just and reasonable and in the public interest to implement a fixed delivery charge rate design as proposed by Staff on the condition that Atmos contribute annually, one percent (1%) of its annual gross revenues (currently, [\*31] approximately \$ 165,000) to be used for an energy efficiency and conservation program.

n55 Approximately 50,000 residential customers multiplied by a minimum of \$ 35 per possible audit requested.

If Atmos does not provide for such a program, the Commission cannot find that the proposed rate design is just and reasonable and in the public interest and therefore, the Commission must reject it. In that event, the Commission determines that it is just and reasonable and in the public interest to maintain the status quo rate design and that no party has justified a change in the revenue requirement.

The Commission finds that an energy and conservation program must be approved by the Commission and must be the result of a collaborative process involving the Staff, Public Counsel, Atmos, the other parties to this case (that wish to participate), the Energy Center of the Missouri Department of Natural Resources, and other parties that the Commission shall designate. As the Commission has found with regard to other companies, [\*32] a successful program may include Energy Star education and communication, appliance rebate and replacement, green construction for old and new homes, Pay As You Save programs, weatherization, energy audits (with follow-up), and others. Such a program may contain a low-income component as well as residential, commercial, and industrial components. The comprehensive program should be designed with methods for gathering and reporting data to analyze its effectiveness.

Therefore, the Commission directs that if Atmos files tariff pages in compliance with this order designed to implement a fixed delivery charge, it shall also set up a new program by meeting with the other parties set out above, and any other social service agency or party that the Commission designates to participate, and design a program to be approved by the Commission and implemented no later than August 31, 2007. The Commission will direct that Atmos file a report regarding the status of any collaborative effort every thirty days. In addition, Atmos must present a program for Commission consideration no later than June 30, 2007. Finally, if the fixed delivery charge rate design is implemented, Atmos shall file on an [\*33] annual basis a report with the Commission for the purpose of evaluating the effect of a fixed delivery charge rate design on energy efficiency and conservation.

If Atmos does not file tariff pages designed to implement a fixed delivery charge rate design, it shall file new tariff pages designed to implement the status quo rate design with the other changes as set out in this Report and Order.

The Commission will issue further orders following this Report and Order to set up the collaborative process to design the conservation program if necessary.

### Seasonal Rates

Atmos recommends one modification to the Staff proposal by seasonally "sculpting" the fixed monthly delivery charge. n56 Atmos proposes that the delivery charge be higher in the winter and lower in the summer. The sculpting of the rates would allow for the same annual revenue collections as Staff's rate design. n57 Atmos argues that the benefits of its sculpting proposal are that it will reduce the risk of customer loss during the summer months and it will aid in customer acceptance of the changed rate design. n58

n56 Ex. 3, pp. 4-5, and Schedule GLS-1.

[\*34]

n57 Tr. 299.

n58 Ex. 3, p. 4.

Staff's fixed monthly delivery charge rate design proposal, as modified by Atmos' sculpting proposal set forth in Schedule GLS-1 as follows:

	Summer	Winter
Butler/Greeley	\$ 15.00	\$ 25.46
Kirkville/Palmyra/old UCG	\$ 15.00	\$ 28.24
Old SEMO/Neelyville	\$ 10.00	\$ 19.23

As set out below, the Commission finds that the problem of customers disconnecting on a seasonal basis should be solved through the seasonal disconnection charges. While the "sculpted" rates may offer less of an incentive for customers to disconnect in the warmer months, it also would have a significant affect on rates in the winter months. The Commission finds that this disparity is not justified.

### Small General Service Rate Class

Staff proposes to create new classes of General Service customers. The basis for this part of Staff's proposal was the large variation in usage between members of the class. Some of the General Service class use zero Ccfs, and some of them use close to a million Ccfs in one year. Staff proposes to split the Small General Services rate class so that customers [\*35] using more than 2,000 Ccf per year will retain the traditional rate structure while those at or below 2,000 Ccf will be under the same rates as residential ratepayers. For the others, there would be a new Medium General Service class, a Large General Service class, and a Large Volume Service class. Staff recommended the traditional rate design for those customers. n59

n59 Tr. 353-354.

Small General Service Customers using less than 2,000 Ccf per year are served with the same meter/regulator and service lines as residential customers. Approximately 80 percent of Atmos' current Small General Service customers use less than 2,000 Ccf per year.

The proposed Medium General Service class would include non-residential customers using from 2,000 to 75,000 Ccf per year. The Large General Service class would include non-residential customers using from 75,000 to 200,000 Ccf per year.

Atmos agrees to accept Staff's proposal to split the general service class and to have uniform classes throughout the state. n60

n60 Ex. 6, pp. 3-4.

[\*36]

Public Counsel believes the Commission should maintain the existing structure for the entire Small General Service rate class. Public Counsel's foremost concern with Staff's proposal is that it will create discontinuity within the Small General Service class. Under Staff's proposal, General Service customers using 2,001 Ccf will pay two to three times as much in non-gas rates as a customer using 2,000 Ccf. n61

n61 Ex.201, p. 26.

The Commission is not persuaded by Public Counsel's argument. The evidence supports Staff's proposal. Whenever classes are distinguished, there must be a dividing line between those classes. The proposal by Staff is logical in that those customers using less than 2,000 Ccf per year are served by the same size and type of equipment as residential customers. Thus, the Commission finds that a residential delivery charge for Small General Services customers using less than 2,000 Ccf per year within the same territory is just and reasonable. The Commission shall adopt the proposal of Staff with [\*37] regard to this issue.

**4. What are the appropriate miscellaneous charges (activation charges for connection, reconnection, and transfer; late payment, NSF, and seasonal reconnection)?**

Atmos Witness Michael H. Ellis sponsors Atmos' proposal to make various miscellaneous charges (connection, reconnection, and transfer; late payment; insufficient funds; and seasonal reconnection) uniform and consistent across its Missouri service area. n62 Mr. Ellis supports the rates proposed with a cost analysis discussed in, and attached to, his testimony. Staff proposes that these miscellaneous charges be based on the actual costs rounded to the nearest whole dollar.

n62 Ex. 10, pp. 2-8.

While Atmos and Staff have reached agreement on all of the issues addressed in the Miscellaneous Charges area, Public Counsel objects to the changes. The exception is for interest paid on customer deposits, a change that would bring parity to all deposits. n63 An agreement was also reached to revise Atmos' proposed tariff language and use the [\*38] generic terminology, instead of the term "activation charge." n64

n63 Ex. 10, p. 7.

n64 Ex. 114.

### Connection, Reconnection, and Transfer Charges

Some areas of Atmos' service territory currently do not have connection, reconnection, or transfer charges. The Commission finds that it is appropriate to make these types of charges uniform within all of Atmos' service territory. In addition, the Commission finds that it is reasonable to align the charges with the actual costs to provide the service.

The actual costs of providing the specific services and applicable rates to be applied on a statewide basis, as agreed to by Atmos and Staff, are: n65

n65 Ex. 114, pp. 5-6; Tr. 635-636.

Type of Charge	Actual Cost	Proposed Charge
Connection - Normal Hours	\$ 23.56	\$ 24.00
Connection - After Normal Hours	\$ 50.09	\$ 50.00
Reconnection - Normal Hours	\$ 23.56	\$ 24.00
Reconnection - After Normal Hours	\$ 50.09	\$ 50.00
Transfer - Normal Hours	\$ 20.02	\$ 20.00
Transfer-After Normal Hours	\$ 46.55	\$ 47.00

[\*39]

The Commission finds the proposed charges to be just and reasonable based on the actual costs to provide such services and shall adopt them.

### NSF Charges

As with the other charges, Staff supports a statewide charge in an amount closely related to the actual costs. Currently, Atmos charges \$ 15.00 for an insufficient funds (NSF) charge for approximately 75 percent of its customers. n66 The rates for the remaining customers have been under cost at \$ 10.00 and Staff was able to discern that charge had been applied only twice in the last three years. Thus, for all practical purposes Atmos has had an NSF charge of \$ 15.00. Therefore, the Commission finds it reasonable to set these charges on a statewide basis in an amount that is closer to the actual costs. The Commission adopts a statewide NSF charge for Atmos of \$ 15.00.

n66 Ex. 117, p. 2.

### Late Payment Fee

Atmos also requests authority to apply the authorized late payment fee found in specific existing tariff sheets (equal to 1.5 percent of the outstanding [\*40] balance) across all rate schedules. The late payment fees existing in Atmos' Missouri tariffs vary in amounts and this change will make the charge consistent across all of Atmos' Missouri service areas. n67 Staff supports and recommends that the late payment fee be consistent throughout the tariff. Public Counsel only addresses this issue in its Prehearing Brief, where this component is listed with those "miscellaneous charges that remain unresolved between the parties."

n67 Ex. 10, pp. 5-6.

The Commission finds that the late payment fee equal to 1.5 percent of the outstanding balance is reasonable and shall be applied on a statewide basis by Atmos.



### Seasonal Reconnection

The proposed seasonal reconnection charge is the most contentious of the Miscellaneous Charges. One-tenth n68 of Atmos' customers disconnect for a month or more each year. n69 Thus causing Atmos to forgo revenues from its investments to those properties (e.g. meters, pipes, mains, etc.). Staff proposes a two-component reconnection charge to [\*41] dissuade seasonal customers that disconnect during the non-winter months and do not pay for the costs associated with providing utility service. n70 Such a customer would pay the traditional reconnection charge (\$ 24.00 proposed); in addition, the customer would make up all missed delivery charges that occurred while the customer was disconnected. Staff proposes a 12-month limitation to the second component, regardless of the reason for disconnection. The purpose of this change is for the company to make up the revenues lost during the months of disconnection. Otherwise, the company has a certain amount of embedded costs that it cannot recoup unless gas service is being provided to that customer.

n68 Mr. Ensrud testified that 1/10 or 7,000 customers disconnect for a month or more each year. (Tr. 651.) However, other evidence indicates that Atmos only has 60,000 customers. Therefore, the Commission assumes the lower number of customers for the sake of this argument.

n69 Tr.651.

n70 Ex. 114, pp. 18-20.

Although [\*42] Atmos proposed seasonally sculpting the rates as a possible way to alleviate some of the seasonal loss concerns, it supports Staff's proposal. n71 Atmos believes that it can recoup sufficient revenue under its sculpted rate proposal without collecting all the missed customer charges. In addition, Atmos' original proposal included a reconnection charge of up to twelve months of a \$ 9.00 statewide customer charge. Atmos requests that regardless of the methodology chosen, the Commission address this concern.

n71 Smith, Ex. 3, p. 4.

Public Counsel does not offer any type of adjustment to Atmos' revenue requirement to adjust for seasonal customers, but argues that it is appropriate to allow customers to disconnect during the non-winter months.

Atmos has a provision similar to Staff's proposal in its tariffs for its current SEMO, Butler, and Kirksville Districts. n72 Those provisions, however, require the payment of the customer charge, and not the volumetric portion, of the missed months where the customer has requested [\*43] the disconnection.

n72 Tr. p. 639 - 640.

As the undisputed evidence shows, Atmos has a significant problem with lost revenues due to ten percent of its customer base disconnecting for a month or more and then reconnecting at the same address. Customers seek to avoid paying the fixed cost of providing gas service when not using gas for heat, and thus shift costs for their meters and equipment during that time to the other customers. The Commission finds that a seasonal reconnection charge is a just and reasonable way to discourage seasonal disconnection while allowing Atmos to recover its fixed costs of offering service to the premises.

The Commission further finds, however, that there is not sufficient justification for recovery of Staff's proposed seasonal reconnection charges up to twelve months. The twelve-month recovery of the fixed delivery charge would be a total of up to: \$ 167.04 (SEMO); \$ 233.16 (WEMO); and \$ 247.32 (NEMO). Customers would pay the \$ 24.00 reconnection fee in addition to the seasonal reconnection [\*44] charges. The Commission finds that Staff's proposed collection of customer charges for up to twelve months would cause a significant barrier to low-income households trying to

get service reconnected for the winter heating season. After carefully examining all the various proposals set forth to solve the seasonal disconnect problem, the Commission is able to find a solution.

The proposal presented to the Commission is for a "seasonal" disconnection charge and all of the evidence suggests that it is customers who disconnect for the warmer months and then reconnect for winter at the same location that cause the issue which needs to be addressed. Thus, Atmos and Staff are seeking to discourage those customers who disconnect during the summer season. The "summer season" is clearly meant to be the time period from March 1 to October 31 as defined in the Commission's Cold Weather Rule. n73 Therefore, it is unreasonable to make the applicable period for the "seasonal" disconnection charge longer than seven months.

n73 4 CSR 240-13.055.

[\*45]

Even with a seven-month cap on the seasonal disconnection charge these fees might be a rate shock for some customers. Because the customers have not previously had the higher fixed delivery charge during the summer months, n74 customers who disconnect on a seasonal basis will be shocked to discover that they must pay as much as \$ 97.44 (SEMO), \$ 136.01 (WEMO), and \$ 144.27 (NEMO), plus the \$ 24.00 reconnection fee, in order to reconnect service. This is especially significant because in all likelihood those customers disconnected because they could not afford to pay the monthly charge in the summer months.

n74 Previous "customer charges" were in the range of \$ 5.00 to \$ 9.05.

Given that the Commission has found the recovery of the fixed delivery charges to be a reasonable cost recovery mechanism, the Commission has determined that the rate shock to the customers justifies a further reduction of the amount of recovery in order to mitigate the rate shock to the customers. The Commission determines that customers would [\*46] not be so shocked by a charge that was one-half of the seven-month summer season. Therefore, the Commission finds that it is just and reasonable to reduce the seven-month cap further by half.

The Commission finds that the seasonal disconnection charge is just and reasonable and in the public interest so long as it is limited to a three-and-one-half-month cap on recovery of the fixed monthly delivery charge. In addition, the Commission finds that this provision should be prospective only. That is, Atmos should not be allowed to recover any reconnection charges that were not in effect at the time of the customer's disconnection. For example, if Atmos files new tariffs with the fixed monthly charge, it must only charge the customer what it could have charged under the tariff that was in effect for that customer at the time of the disconnection.

##### **5. Should Atmos' districts be consolidated for purposes of setting margin non-gas rates in this case?**

Atmos currently has six sets of base tariffs and six purchased gas adjustments (PGAs) for its Missouri service areas (although there are seven separate PGA rate filings). The areas are referred to as District B (Butler); District K (Kirksville); [\*47] District S (Southeast Missouri, all of which are properties formerly operated by Associated Natural Gas Company); District G (Greeley) formerly operated by Greeley Gas Company; District U (Hannibal/Canton/Palmyra/Neelyville) and District P (Palmyra), both formerly operated by United Cities Gas Company. Staff proposes to consolidate base rates into three geographic areas. n75 A map depicting this proposal was entered into evidence as Exhibit 100. Staff's proposal is very similar to that of Atmos n76 and is supported by Atmos. OPC opposes this consolidation.

n75 Ex. 110.

n76 Ex. 5.

The consolidated rates are supported by the Staff's cost studies and based on seven different districts' rates. n77 The consolidation will combine the current rate districts into three service territories based on location, and will set a single rate for all customers in a particular class in a particular geographic area. By consolidating the districts, customers in neighboring communities will pay similar non-gas rates. n78

n77 Tr. 298.

[\*48]

n78 Ex. 110, p. 4.

The new areas would be as follows:

- i. NEMO: Kirksville, Palmyra, Hannibal/Canton/Bowling Green
- ii. SEMO: Neelyville and SEMO
- iii. WEMO: Greeley and Butler/Rich Hill

Public Counsel opposes consolidating the districts without comprehensive data and cost studies. Public Counsel argues that the embedded costs for each district may not be the same. In addition, Public Counsel argues that customer confusion will result from the widely varying changes in rates as the result of consolidation.

The Commission is persuaded by Staff's evidence that the districts should be consolidated. Staff identified what appear to be inequities between users in various districts of Atmos. A customer using 720 Ccf per year would pay annual non-gas costs as follows: n79

Kirksville -- \$ 138

Palmyra -- \$ 163

Hannibal/Canton/Bowling Green -- \$ 269

Greeley -- \$ 290

Butler -- \$ 213

Neelyville -- \$ 269

Thus, Staff has shown that customers in neighboring districts pay much different costs for the same gas usage.

n79 Tr. 37-39; Ex. 112, pp. 8-9; Ex. 142, p. 7.

[\*49]

The cost for Atmos to serve similarly situated customers in neighboring districts, such as the combining of three adjoining northeast Missouri districts into one service territory, is about the same. Atmos does not buy equipment, such as meters or mains, in quantities intended to serve just one "legacy" district. Atmos service employees serve *all* customers in each of its geographical service areas. Corporate overhead expenses associated with serving a residential customer are also indifferent as to the "legacy" district that customer lives in.

While there may be some difference in costs due to the vintage of the distribution equipment in various "legacy" districts at any given point in time, Atmos' cost to provide service today do not change from area to area. Moreover, the cost of meters, regulators, and service lines is the same for all districts. In addition, when a customer calls Atmos customer service, the call is first answered by a Company representative located in one of three out-of-state call centers. If that call cannot be addressed, then it is routed to one of seven Missouri call centers which serve the surrounding area.

These calls are routed without regard for the [\*50] predecessor company that served the area ten years ago. Related billing and customer service costs do not vary among Atmos' current seven districts.

For Atmos to make the attempt to collect and break out its costs to serve each of seven "legacy" districts is unnecessary -- particularly in light of the reasonableness of combining these districts into their natural geographic service areas. The Commission finds that it is just and reasonable to consolidate the base rate districts of Atmos as proposed by Staff.

#### **6. Should Atmos' PGA tariffs be consolidated for purposes of setting gas rates in this case?**

Staff recommends consolidating Atmos' PGA rate districts, by pipelines served, into the following four districts: (1) Butler and Greeley; (2) Hannibal/Canton, Bowling Green and Palmyra; (3) Kirksville and (4) SEMO and Neelyville.

Butler and Greeley are combined into one district because their primary source of gas comes from the Mid Continent Basin. As a result, the commodity costs are basically the same, even though the gas is being transported over two different pipelines.

For the SEMO/Neelyville consolidated PGA district, Staff's witness, Mr. Imhoff, noted that NGP&L pipeline [\*51] currently feeds both Neelyville and a part of SEMO as well, even though SEMO has four different pipelines feeding into it.

At hearing, Mr. Imhoff also testified that Staff will have each individual "legacy" district take care of its respective Actual Cost Adjustment (ACA) balances to "zero them out." The current balances are very close with the exception of the ACA factor, which will run for 12 months to recover or refund any over- or under-recovery. n80 Although Atmos proposed a statewide consolidation for the PGA, its witness testified that consolidation of the four areas identified by Staff's direct testimony is acceptable. n81

n80 Tr. 242.

n81 Ex. 6, p. 4.

Public Counsel opposes PGA consolidation. Public Counsel argues that the rates vary significantly among districts, and the parties have offered no compelling reason other than administrative burden to alter the PGA structure. Gas costs represent 73 percent to 82 percent of a customer's bill, and consolidating could have a substantial negative effect on [\*52] customers in areas with lower rates.

The Commission finds that PGA consolidation as proposed by Staff will simplify and improve the PGA/ACA rate process by making it more efficient as a result of reducing the current number of filings made by Atmos. This is accomplished by logically identifying the PGA computation by pipeline or supply source. New, consolidated PGA districts have similar transportation rates and gas supply sources. Such consolidation is consistent with how other regulated LDCs (e.g., AmerenUE) currently file PGA rate filings. In addition, one company is currently doing all gas purchasing for each of the districts, and employing the same hedging program and strategy for Missouri. Finally, as Staff's testimony showed, under the current PGA rates, "the maximum rate differential between the various proposed PGA rate district consolidations . . . [is] \$ .0309 per Ccf." n82 Thus, the effect on customer rates will be insignificant.

n82 Ex. 120, p. 2.

In addition, although the four PGA areas do not align [\*53] exactly (Kirksville is the exception) with the geographic non-gas rates, they are substantially the same in most areas and, therefore, the benefits of bill comparability will be achieved if the Commission adopts the four areas as recommended by Staff. The Commission finds the PGA consolidation to be reasonable and shall adopt Staff's proposal.

#### **7. Other Tariff Issues:**

- a. Should a cash-out policy be implemented?
- b. Should the Commission allow third-party administered pools for cash-outs?
- c. What is the appropriate level of lost and unaccounted gas?
- d. Should the Commission approve an Economic Development Rider?
- e. Should the mains extension policy and the determination of amounts to be charged be changed in this case?

#### **Cash-Out Policy**

The cash-out provision allows transportation customers to resolve imbalances by cash payments instead of making up imbalances with gas volumes in kind. This provision replaces Atmos' existing policy of charging \$ 15.00 per Mcf when the balance is negative, or absorbing the gas when the imbalance is positive. Whether the imbalance is positive or negative, a transportation customer will pay a price determined by [\*54] a formula that uses a published industry price. If the imbalance is greater than 5 percent of the monthly contract volume, the price will be inflated or deflated by an index referenced in the tariff. This standardized policy will replace Atmos' current practice of applying varying policies. Atmos also agrees to make minor changes to the transportation tariffs.

Public Counsel's only opposition noted in testimony is that large transportation customers would be allowed to create pools that would allow pool members to offset imbalances, thus allowing large volume customers flexibility at smaller ratepayer expense. According to Staff, the only customers on Atmos' system that could pool are the school districts, which are allowed to pool by statute.

The Commission finds that it is just and reasonable to have a standardized policy regarding cash-outs. Furthermore, there was no evidence that this policy will affect any customer or revenues of Atmos in any manner, other than school districts which all allowed to pool under current Missouri statutes. Thus, the Commission finds in favor of Atmos on this issue.

#### **Third-Party Administered Pools for Cash-Out**

Atmos proposes to allow third [\*55] parties to create pools that would allow pool members to offset imbalances caused by transport customers taking more or less gas from the system than the amount under contract. According to Staff, the only customers on Atmos' system that could pool are the school districts which are already allowed to pool by *Section 393.310, RSMo*. Public Counsel has the same concerns as with the Cash-Out issue above.

For the reasons stated above, the Commission finds in favor of Atmos' proposal.

#### **Level of Lost and Unaccounted Gas**

The issue of the level of lost and unaccounted gas has been settled among the parties and is addressed in the Partial Non-Unanimous Stipulation and Agreement. n83

n83 Stipulation, page 5; see also, Staff's Memorandum in Support of the Stipulation, p. 4.

#### **Economic Development Rider**

An Economic Development Rider (EDR) encourages industrial customers to use Atmos' natural gas service by providing limited discounts. n84 Staff carefully analyzed the proposal [\*56] and recommended that it be adopted. n85

n84 Ex. 9.

n85 Ex. 114.

Public Counsel's testimony that the EDR would force residential and small customers to subsidize industry discounts is unsupported and contrary to Staff's analysis indicating that generally, a new industrial customer will generate revenues and defray costs beyond the initial discounted amounts.

The Commission is persuaded by Mr. Ensrud's Surrebuttal testimony regarding this matter. n86 He testifies that a new customer will generate revenues and defray fixed costs to the point that both Atmos stockholders and ratepayers will benefit. n87 In addition, Mr. Ensrud testifies that secondary benefits of the potential economic development, such as new jobs, new tax revenue, and increased property values are also to be taken into consideration. The Commission finds that it is just and reasonable and in the public interest to allow an EDR as proposed by Atmos. The Commission finds for Atmos with regard to this issue.

n86 Ex. 116, pp. 9-11.

[\*57]

n87 Ex. 114, p. 10.

#### **Mains Extension Policy and the Determination of Amounts to be Charged**

Atmos proposes to eliminate its current minimum line extension policy. Currently, customers may receive up to 150 feet of gas main extension free. Instead, Atmos would use a computer model to estimate the cost of the main and the revenue that will be produced. The initial customer would be compensated by the utility if additional customers come on to the extended portion of the main. n88 Staff proposes one exception with regard to refunds, but otherwise agrees with Atmos' proposal.

n88 Ex. 114, p. 13-14.

Public Counsel opposes Atmos' proposal to eliminate the minimum line extension, and subject every new residential and small business customer to a feasibility review resulting in an up-front fee for main extensions. "A reasonable fee-free line extension is both a reasonable obligation to impose on a public utility and an investment [\*58] in future earnings for the utility. n89

n89 Ex. 202, p. 38-39.

The Commission agrees with Public Counsel and finds that the main extension policy should not be eliminated at this time. Proposing such a drastic change from 150 feet free to zero feet free is not a reasonable proposal. The Commission finds in favor of Public Counsel on this issue. Atmos shall not implement a new main extension policy.

#### **Conclusions of Law**

The Missouri Public Service Commission has arrived at the following conclusions of law.

#### **Jurisdiction**

Atmos is a public utility, and a gas corporation, as those terms are defined in *Section 386.020(42)* and (18), RSMo 2000. As such, Atmos is subject to the Commission's jurisdiction pursuant to Chapters 386 and 393, RSMo.

### Burden of Proof

*Section 393.150.2*, RSMo 2000, provides in part, "At any hearing involving a rate sought to be increased, the burden of proof to show that the increased rate or [\*59] proposed increased rate is just and reasonable shall be upon the . . . gas corporation . . . and the commission shall give to the hearing and decision of such questions preference over all other questions pending before it and decide the same as speedily as possible."

### Commission's Authority

Pursuant to *Section 393.130.1*, RSMo 2000, the Commission has authority to prohibit the implementation of gas rates that are unjust or unreasonable.

*Section 393.140* authorizes the Commission to determine just and reasonable rates. *Section 393.150*, in pertinent part, authorizes the Commission to suspend for a period of time any schedule stating new rates, charges, rules, regulations, or practices, and to hold "a hearing concerning the propriety of such rate, charge, . . . rule, regulation or practice." *Section 393.270* provides in paragraph 4 that in determining the price to be charged, "the commission may consider all facts which in its judgment have any bearing upon a proper determination of the question . . ." The courts have [\*60] held that this statute means that the Commission's determination of the proper rate must be based on consideration of all relevant factors. n90

n90 *State exrel. Missouri Water Co. v. Public Service Comm'n*, 308 S.W.2d 704, 719 (Mo. 1957); *State ex rel. Midwest Gas Users' Ass'n v. Public Service Commission*, 976 S.W.2d 470, 479 (Mo. App., W.D. 1998); *State exrel. Office of Public Counsel v. Public Service Com'n of Missouri*, 858 S.W.2d 806 (Mo. App., W.D. 1993).

In determining whether rates are just and reasonable, the Commission must balance the interests of the investor and the consumer. n91 The Commission's failure to establish just and reasonable rates would, in fact, violate the United States Constitution. In discussing the need for a regulatory body to institute just and reasonable rates, the United States Supreme Court has held as follows:

Rates which are not sufficient to yield a reasonable return on the value [\*61] of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. n92

n91 *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1943).

n92 *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 690(1923).

In the same case, the Supreme Court provided the following guidance on what is a just and reasonable rate:

What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a 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 [\*62] 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 effi-

cient 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. n93

n93 *Id. at 692-93.*

In undertaking the balancing required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:

Agencies to whom this [\*63] legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances. n94

n94 *Federal Power Commission v. Natural Gas Pipeline Co. 315 U.S. 575, 586 (1942).*

The dominant purpose in creation of the Commission is public welfare. n95 *Section 386.610* reads, in relevant part, that "[t]he provisions of this chapter shall be liberally construed with a view to the public welfare, efficient facilities and substantial justice between patrons and public utilities." The Commission must weigh the benefits and detriments to all the groups affected by its decision.

n95 *Alton R. Co. v. Public Service Commission, 110 S.W.2d 1121, 1125 (Mo. App. 1937).*

[\*64]

Under *Section 386.270, RSMo 2000*, all rates of a public utility that have been approved by the Commission are prima facie lawful and reasonable until found otherwise in a suit brought for that purpose pursuant to the provisions of Chapter 386.

## DECISION

### Stipulation And Agreement

Atmos, the Staff, and Public Counsel filed on November 29, 2006, their *Partial Non-Unanimous Stipulation and Agreement*, which sets forth issues settled among the parties.

Pursuant to *4 CSR 240-2.115(2)(C)*, because no parties objected within seven days to the *Partial Non-Unanimous Stipulation and Agreement*, the Commission may, by operation of law, treat this Agreement as a unanimous stipulation and agreement.

The Stipulation addressed the following issues as resolved among the parties: Billing Determinants; Other Post-Retirement Benefits (OPEB) Contribution; Class Share of Revenue by District / Class Cost of Service; Customer Service Requirements and Reporting; PGA Minimum Filing Requirements; Depreciation Record Keeping and Reporting; and Gas Loss Reporting.

Based on the agreement of the parties, the [\*65] Commission concludes that the Agreement constitutes a just and reasonable settlement of all of the issues included therein.



## Contested Issues

### 1. Revenue Requirement

- a. Level of Expense
- b. Rate of Return / Return on Equity
- c. Level of Revenue Excess / Deficiency

The Commission concludes that rates designed to produce a zero net revenue requirement allowing for a stipulated gross annualized revenue of \$ 16,507,737 are just and reasonable in that they meet Atmos' prudent operating expense and allow an opportunity to earn a reasonable return on the value of the private property dedicated to public service.

### 2. Depreciation and Reserve Amortization

The Depreciation issues are resolved among the parties in accordance with the Stipulation, which constitutes a just and reasonable settlement of the issues.

The Commission concludes that, as a whole, the annual depreciation accrual should be reduced by approximately \$ 591,000 and that, by Atmos entering a negative amortization of \$ 591,000 to the depreciation reserve account, this provides an immediate benefit to Atmos' customers by lowering Atmos' depreciation expense. The Commission concludes that based on these facts, [\*66] this is a just and reasonable result.

### 3. Rate Design

Based on the specific facts in this case, the Commission finds that placing all non-gas costs into a fixed delivery charge, within the context of a zero revenue increase and the consolidation of the operating districts into three service areas (NEMO, WEMO, and SEMO) will provide for just and reasonable rates *if* it is accompanied by a meaningful energy efficiency and conservation program as described above. Thus, the Commission concludes that no party justified a change in revenue requirement, and absent the conservation program, the Commission must reject the proposed fixed delivery charge rate design. If Atmos chooses to enter into a significant energy efficiency and conservation program as set out in this order to be approved by the Commission, it may file tariffs including a fixed delivery charge rate design.

The Commission determines that the problem of seasonal disconnects is most appropriately handled in the context of a seasonal disconnection charge. Thus, the Commission concludes the proposed seasonally "sculpted" rates are not just and reasonable.

The Commission further concludes that creating a Small General [\*67] Service class that is based on the same operating parameters and cost of service of the Residential class provides just and reasonable rates for non-residential customers.

The Commission also concludes that maintaining the traditional rate design for Medium General Service and Large General Service customers provides just and reasonable rates to the members of these service classes.

### 4. Miscellaneous Charges

The Commission concludes that uniform, statewide cost-based charges for Activation, Reconnection, Transfer, Late Payment, and NSF are just and reasonable.

The Commission concludes that the "seasonal" reconnection charge is a just and reasonable method of discouraging customers from disconnecting from the system on a seasonal basis. In addition, the seasonal reconnection charge will allow Atmos to recover its fixed costs of serving the customer and prohibit the shifting of costs from the customer who disconnects to all other customers. The Commission further determines, however, that for the charge to truly be a "seasonal" disconnection charge, it cannot reasonably recover more than seven months of the fixed monthly charge. The Commission further determines that the recovery [\*68] of up to seven months of a fixed monthly delivery charge would be so shocking to customers attempting to reconnect as to be unreasonable. Therefore the Commission determines that the recovery of the fixed monthly delivery charge for the purpose of a seasonal reconnection fee should be limited to three-and-one-half months. In addition, Atmos shall only collect the seasonal disconnection charge on a prospective basis.

### 5. Company PGA Tariffs Consolidation

The Commission concludes that the consolidation to four PGA districts provides for just and reasonable rates because the consolidation is based on the cost similarity of interstate pipelines that serve the districts and/or the cost similarity of the sources of gas supply to the districts.

#### **6. Company District Consolidation**

Because the costs to provide service to each service area do not change among those areas, the Commission concludes that the consolidation of operating districts into three geographic service areas (NEMO, WEMO, SEMO) for the purpose of setting non-gas margin rates (the fixed delivery charge) provides for just and reasonable rates.

#### **7. Other Tariff Issues**

The Commission concludes that the Cash-Out [\*69] Policy and the Economic Development Gas Service Rider provide for just and reasonable rates and that no credible evidence opposing these tariff issues has been provided by Public Counsel.

The Commission concludes that Third-Party Administered Pools for cash-outs provide for just and reasonable rates and notices that school districts are permitted to pool under *Section 393.310*.

The Lost and Unaccounted Gas issue is resolved among the parties in accordance with the Stipulation, which constitutes a just and reasonable settlement of this issue.

With regard to the main extension policy proposed by Atmos and Staff, the Commission concludes that it is not a just and reasonable policy, and therefore it must be rejected.

#### **CONCLUSION**

The Commission has thoroughly considered the facts of this case and the arguments of all the parties. The Commission has found that the status quo rate design is just and reasonable and that the volumetric rates encourage conservation. The Commission agrees with its Staff that the facts of this case present an opportunity to implement just and reasonable rates under a rate design that is quite novel in the state of [\*70] Missouri. However, the Commission has determined that it is not just and reasonable to relinquish the conservation measures currently in place in the form of volumetric rates without also implementing a significant efficiency and conservation program to offset the loss of conservation encouraged by the volumetric portion of the rate. Therefore, the Commission has determined that Atmos shall maintain the status quo rate design unless it proceeds with a significant energy efficiency and conservation program as set out in the body of this order. If Atmos chooses to go forward with such a program, it may file new tariffs designed to implement not only that program, but also a fixed delivery charge rate design.

#### **IT IS ORDERED THAT:**

1. Exhibit 144 is admitted into evidence.
2. All pending motions and requests for relief not otherwise granted are denied.
3. The Partial Non-Unanimous Stipulation and Agreement filed on November 29, 2006, is hereby approved as a resolution of all issues contained therein (See Attachment A).
4. The parties are ordered to comply with the terms of the Stipulation and Agreement.
5. The proposed gas service tariff sheets (Tariff No. YG-2006-0762) submitted on [\*71] April 7, 2006, by Atmos Energy Corporation for the purpose of increasing rates for gas service to retail customers are rejected. The tariff sheets rejected are:

#### **P.S.C. MO. No. 2**

#### **Original Sheet No. 1 through Original Sheet No. 113**

6. Atmos Energy Corporation may file tariffs that comply with this Report and Order.
7. If Atmos Energy Corporation files tariffs that include a fixed delivery charge rate design, it shall also set up an energy efficiency and conservation program as outlined in the body of this order to be implemented no later than August 31, 2007, and shall present a program to the Commission for consideration no later than June 30, 2007.

2007 Mo. PSC LEXIS 278, \*

8. If Atmos Energy Corporation files tariffs that include a fixed delivery charge rate design, beginning on April 1, 2007, Atmos shall report to the Commission no later than the first day of every month as to the status of the collaborative process set out herein.

9. If Atmos Energy Corporation files tariffs that include a fixed delivery charge rate design, it shall file on an annual basis a report with the Commission for the purpose of evaluating the effectiveness of a fixed delivery charge rate design on energy efficiency [\*72] and conservation.

10. This Report and Order shall become effective on March 4, 2007.

**BY THE COMMISSION**

Davis, Chm., and Appling, C., concur; Murray, C., concurs, with separate concurring opinion attached; Gaw and Clayton, CC., dissent, with separate dissenting opinion(s) to follow; and certify compliance with *Section 536.080, RSMo 2000.*"

Dated at Jefferson City, Missouri, on this 22nd day of February, 2007.

**CONCURBY: MURRAY**

**CONCURRING OPINION OF COMMISSIONER CONNIE MURRAY**

I write separately to express my disagreement with conditioning the fixed variable rate design on an annual contribution of one percent (1%) of Atmos' annual gross revenues to an energy efficiency and conservation program. Under the circumstances of this case, Atmos' rates are ripe for being redesigned, as the record supports. It is inappropriate and likely extrajudicial for the Commission to order an expenditure not proposed by any party on the record for a program neither proposed nor yet designed.

Atmos has committed to spend \$ 78,000 for low income weatherization and has agreed to institute a residential efficiency audit program for all residential customers. In addition, [\*73] Atmos committed to educating customers about the delivery charge prior to and during the implementation. Atmos has further committed to participate in collaborative meetings with the Staff and Public Counsel.

The new fixed variable rate design will eliminate the inherent conflict in the traditional rate design between the shareholders whose fixed cost recovery decreases when less gas is sold and ratepayers who only save money by using less gas. The new rate design provides revenue stabilization that removes the disincentive from the Company to encourage energy efficiency and conservation.

Rather than create a new expenditure program from evidence aliunde and Commission speculation, the Commission could have addressed its concern for tangible results in energy efficiency and conservation in a simpler way. It should have merely directed Atmos to file and Staff to review annually reports tracing the effect of the new rate design upon energy efficiency and conservation. The rate design's effectiveness could be evaluated prior to Atmos' next rate case and collaborative discussions in the meantime could explore potential improvements to Atmos' energy efficiency and conservation programs. [\*74]

Otherwise, I agree with the Report and Order.

**Respectfully submitted,**

Connie Murray, Commissioner

Dated at Jefferson City, Missouri on this 22nd day of February 2007.



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

45. Refer to the Seelye Testimony, page 6. Delta states that its proposal to recover most of the customer-related costs through the customer charge will eliminate rate subsidies within the residential class. Provide an example of how the current rate design for residential customers creates a subsidy.

RESPONSE:

The following table compares the current rate design (with current charges adjusted on a pro-rata basis to yield the proposed residential rate increase) to the actual cost of providing service from Delta's cost of service study submitted in this proceeding:

<b>Rate Component</b>	<b>Rates Based on Current Design That Yield the Proposed Increase</b>	<b>Actual Cost of Service</b>
Customer Charge	\$13.16/Cust/Mo	\$24.157/Cust/Mo
Volumetric Charge	\$5.5848/Mcf	\$3.09/Mcf

The current residential rate design creates a subsidy because the customer and volumetric charges billed to customers do not reflect the cost of providing service. With the current rate design, subsidies are created when a customer's usage differs from the class average. For example, a customer with significant space heating requirements having an annual usage of 85 Mcf would be charged approximately \$633 for the year ( $85 \times \$5.5848 + 12 \times \$9.80 \cong \$633$ ). However, the actual cost of providing service to this customer is \$553 ( $85 \times \$3.09 + 12 \times \$24.157 \cong \$553$ ). Therefore, the current rate design would result in this customer paying a subsidy of \$80 annually.

Sponsoring Witness:

William Steven Seelye



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

46. Refer to the Seelye Testimony, page 15. Provide an electronic copy of the cost of service study, with all formulae intact.

RESPONSE:

Please see attached.

Sponsoring Witness:

William Steen Seelye

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand
<b>Gas Plant at Original Cost</b>										
Underground Storage Plant	PT350	F003	\$ 12,166,437	12,166,437	-	-	-	-	-	-
350-357 Underground Storage Plant	PTST		\$ 12,166,437	\$ 12,166,437	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Storage Plant	PT365	F005	\$ 51,227,484	-	-	51,227,484	-	-	-	-
<b>Transmission Plant</b>										
325-371 Transmission	PT374	F008	\$ 322,191	-	-	-	-	-	322,191	-
Distribution Plant	PT375	F008	113,715	-	-	-	-	-	113,715	-
374 & 304 Land and Land Rights	PT376	F009	61,633,982	-	-	-	-	-	-	-
375 Structures & Improvements	PT378	F008	1,356,370	-	-	-	-	-	-	26,786,129
376 Mains	PT379	F008	480,352	-	-	-	-	-	1,356,370	-
378 Meas. & Reg. Sta. Equip. - General	PT380	F010	12,797,407	-	-	-	-	-	480,352	-
379 Meas. & Reg. Sta. Equip. - City Gate	PT381	F011	8,917,576	-	-	-	-	-	-	-
380 Services	PT382	F011	3,145,615	-	-	-	-	-	-	-
381 Meters	PT383	F011	3,093,300	-	-	-	-	-	-	-
382 Meter Installations	PT384	F011	1,530,217	-	-	-	-	-	-	-
383 House Regulators	PT385	F011	-	-	-	-	-	-	-	-
384 House Regulator Installations	PT387	F011	-	-	-	-	-	-	-	-
385 Industrial Meas. & Reg. Equip.	MTOVT		-	-	-	-	-	-	-	-
387 Other Equipment			-	-	-	-	-	-	-	-
Mt. Olivet			-	-	-	-	-	-	-	-
Sub-Total Distribution Plant	PTDSUB		\$ 93,390,725	-	-	-	-	-	2,272,628	26,786,129
Transmission & Distribution Subtotal	TDSUB		\$ 144,618,209	\$ -	\$ -	51,227,484	\$ -	\$ -	2,272,628	26,786,129
U-T-D Subtotal	PTSUB		\$ 156,784,646	12,166,437	-	51,227,484	-	-	2,272,628	26,786,129
117 Gas Stored Underground/Non-Current	PT117	F003	\$ 4,208,069	-	-	-	-	-	-	-
301-303 Intangible Plant	PT301	PTSUB	53,151	4,208,069	-	-	-	-	-	-
389-399 General Plant	PT389	PTSUB	19,294,293	1,497,231	-	17,366	-	-	770	9,081
Common Utility Plant	PTCP	PTSUB	-	-	-	6,304,177	-	-	279,675	3,296,365
Total Plant in Service	PTIS		\$ 180,340,159	17,875,861	-	57,549,027	-	-	2,553,073	30,091,574



Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
<u>Gas Plant at Original Cost</u>							
Underground Storage Plant							
350-357 Underground Storage Plant	PT350	F003	-	-	-	-	-
Total Storage Plant	PTST	\$	\$	\$	\$	\$	\$
Transmission Plant							
325-371 Transmission	PT365	F005	-	-	-	-	-
Distribution Plant							
374 & 304 Land and Land Rights	PT374	F008	-	-	-	-	-
375 Structures & Improvements	PT375	F008	-	-	-	-	-
376 Mains	PT376	F009	34,847,853	-	-	-	-
378 Meas. & Reg. Sta. Equip. - General	PT378	F008	-	-	-	-	-
379 Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	-	-	-	-	-
380 Services	PT380	F010	-	12,797,407	-	-	-
381 Meters	PT381	F011	-	-	8,917,576	-	-
382 Meter Installations	PT382	F011	-	-	3,145,615	-	-
383 House Regulators	PT383	F011	-	-	3,093,300	-	-
384 House Regulator Installations	PT384	F011	-	-	-	-	-
385 Industrial Meas. & Reg. Equip.	PT385	F011	-	-	1,530,217	-	-
387 Other Equipment	PT387	F011	-	-	-	-	-
Mt. Olive	MITOVT		-	-	-	-	-
Sub-Total Distribution Plant	PTDSUB		34,847,853	12,797,407	16,686,708	-	-
Transmission & Distribution Subtotal	TDSUB	\$	\$	\$	\$	\$	\$
U-T-D Subtotal	PTSUB		34,847,853	12,797,407	16,686,708	-	-
117 Gas Stored Underground/Non-Current	PT117	F003	-	-	-	-	-
301-303 Intangible Plant	PT301	PTSUB	11,814	4,338	5,657	-	-
389-399 General Plant	PT389	PTSUB	4,268,460	1,574,879	2,053,506	-	-
Common Utility Plant	PTCP	PTSUB	-	-	-	-	-
Total Plant in Service	PTIS		39,148,127	14,376,625	18,745,871	-	-

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand
<b>Gas Plant at Original Cost (Continued)</b>										
Construction Work In Progress										
Underground Storage										
Transmission	CWIPUS	F003	\$ -	-	-	-	-	-	-	-
Distribution Mains	CWIPTR	F005	\$ 1,659,416	-	-	1,659,416	-	-	-	-
Other Distribution	CWIPDM	F009	\$ 120,125	-	-	-	-	-	-	52,206
General	CWIPOD	PTDSUB	\$ -	-	-	-	-	-	-	-
	CWIPOD	PT389	\$ 496,011	38,490	-	162,066	-	-	7,190	84,742
Total CWIP	CWIP		\$ 2,275,552	38,490	-	1,821,482	-	-	7,190	136,948
Total Gas Plant at Original Cost	PTT		\$ 182,615,711	17,914,352	-	59,370,508	-	-	2,560,263	30,228,522
			\$ 182,615,711							

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains		Services		Meters		Customer Accounts		Customer Service Expense	
			Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer		
<u>Gas Plant at Original Cost (Continued)</u>												
Construction Work in Progress												
Underground Storage												
Transmission	CWIPUS	F003	-	-	-	-	-	-	-	-	-	-
Distribution Mains	CWIPTR	F005	-	-	-	-	-	-	-	-	-	-
Other Distribution	CWIPDM	F009	67,919	-	-	-	-	-	-	-	-	-
General	CWIPOD	PTDSUB	-	-	-	-	-	-	-	-	-	-
	CWIPCO	PT389	110,246	-	40,486	-	52,791	-	-	-	-	-
Total CWIP	CWIP		178,165	-	40,486	-	52,791	-	-	-	-	-
Total Gas Plant at Original Cost	PTT		39,326,292	-	14,417,111	-	18,798,662	-	-	-	-	-

DELTA NA - GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand
<b>Net Cost Rate Base</b>										
Total Gas Utility Plant at Original Cost			\$ 182,615,711	\$ 17,914,352	-	\$ 59,370,508	-	\$ -	\$ 2,560,263	\$ 30,228,522
Less:										
Reserve for Depreciation										
Underground Storage	DEPRUS	PTST	4,415,910	4,415,910	-	-	-	-	-	-
Transmission	DEPTR	F005	17,700,180	-	17,700,180	-	-	-	-	-
Distribution	DEPRDI	PTDSUB	30,163,682	-	-	-	-	-	734,022	8,651,483
General	DEPRGE	PT389	9,156,095	710,510	-	2,991,643	-	-	132,720	1,564,288
Common	DEPRCO	PTCP	-	-	-	-	-	-	-	-
Total Depreciation Reserve	DEPR		\$ 61,435,867	\$ 5,126,420	-	\$ 20,691,823	-	\$ -	\$ 866,741	\$ 10,215,771
Customer Advances For Construction	CAD	CADAL	51,708	-	-	-	-	-	-	18,609
Accum. Deferred Income Taxes	DIT	PTSUB	21,216,188	1,646,369	-	6,932,132	-	-	307,533	3,624,714
Investment Tax Credit	ITC	PTSUB	-	-	-	-	-	-	-	-
Deferred Income Taxes-FAS 109	FAS109	PTSUB	-	-	-	-	-	-	-	-
<b>PLUS:</b>										
Materials and Supplies	MSP	PTSUB	434,879	33,746	-	142,091	-	-	6,304	74,298
Prepayments	PPY	PTSUB	1,562,000	121,211	-	510,365	-	-	22,642	266,862
Gas Stored Underground	GSU	F003	9,879,627	9,879,627	-	-	-	-	-	-
Cash Working Capital	CWC	OMT	1,445,639	47,257	32,330	352,280	34,669	8,836	18,245	216,379
Adjustments:										
Unamortized Debt		PTSUB	5,704,177	442,642	-	1,863,771	-	-	82,683	974,539
Net Cost Rate Base	NCRB		\$ 118,938,270	\$ 21,666,046	\$ 32,330	\$ 34,615,060	\$ 34,669	\$ 8,836	\$ 1,515,862	\$ 17,901,507

DELTA NATURAL GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
<b>Net Cost Rate Base</b>							
Total Gas Utility Plant at Original Cost		\$	39,326,292 \$	14,417,111 \$	18,798,662 \$	- \$	-
<b>Less:</b>							
Reserve for Depreciation							
Underground Storage	DEPRUS	PTST	-	-	-	-	-
Transmission	DEPTR	F005	-	-	-	-	-
Distribution	DEPROI	PTDSUB	11,255,269	4,133,354	5,389,535	-	-
General	DEPRGE	PT389	2,035,086	747,358	974,490	-	-
Common	DEPRCO	PTCP	-	-	-	-	-
Total Depreciation Reserve	DEPR		13,290,375 \$	4,880,712 \$	6,364,025 \$	- \$	-
Customer Advances For Construction	CAD	CADAL	24,209	8,890	-	-	-
Accum. Deferred Income Taxes	DIT	PTSUB	4,715,631	1,731,752	2,258,055	-	-
Investment Tax Credit	ITC	PTSUB	-	-	-	-	-
Deferred Income Taxes-FAS 109	FAS109	PTSUB	-	-	-	-	-
<b>PLUS:</b>							
Materials and Supplies	MSP	PTSUB	96,659	35,497	46,284	-	-
Prepayments	PPY	PTSUB	347,179	127,497	166,245	-	-
Gas Stored Underground	GSU	F003	-	-	-	-	-
Cash Working Capital	CWC	OMT	281,501	96,318	136,685	220,794	344
Adjustments:							
Unamortized Debt		PTSUB	1,267,843	465,598	607,100	-	-
Net Cost Rate Base	NCRB		23,289,259 \$	8,520,666 \$	11,132,896 \$	220,794 \$	344

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage		Transmission		Transmission		Distribution Structures & Equipment Demand	Distribution Mains Demand	
				Demand	Commodity	Demand	Commodity	Demand	Commodity		Demand	Commodity
<b>Labor Expenses</b>												
<b>Production Expenses</b>												
<b>Operation &amp; Maintenance</b>												
753 Wells and Gathering	LB 753	F006	8,355	-	-	-	-	-	8,355	-	-	-
754 Compressor Station	LB754	F006	54,680	-	-	-	-	-	54,680	-	-	-
764 Maintenance of Wells and Gathering	LB764	F006	316	-	-	-	-	-	316	-	-	-
765 Maintenance of Compressor Station	LB765	F006	12,318	-	-	-	-	-	12,318	-	-	-
Total Production Operation & Maintenance Expenses			75,669	-	-	-	-	-	75,669	-	-	-
807-813 Procurement Expenses	LB807	DMCM	\$ -	-	-	-	-	-	-	-	-	-
<b>Storage Expenses</b>												
<b>Operation</b>												
814 Operations Supervision and Engineer	LB814	OSE	-	-	-	-	-	-	-	-	-	-
815 Maps and Records	LB815	F003	-	-	-	-	-	-	-	-	-	-
816 Well Expenses	LB816	F003	61,280	61,280	-	-	-	-	-	-	-	-
817 Lines Expenses	LB817	F003	-	-	-	-	-	-	-	-	-	-
818 Compressor Station Exp - Payroll	LB818	F004	21,113	-	21,113	-	-	-	-	-	-	-
819 Compressor Station Fuel and Power	LB819	F004	-	-	-	-	-	-	-	-	-	-
820 Measurement and Regulator Station	LB820	F003	-	-	-	-	-	-	-	-	-	-
821 Purification of Natural Gas	LB821	F004	-	-	-	-	-	-	-	-	-	-
823 Gas losses	LB823	F004	-	-	-	-	-	-	-	-	-	-
824 Other Expenses	LB824	F004	-	-	-	-	-	-	-	-	-	-
825 Storage Well Royalties	LB825	F003	-	-	-	-	-	-	-	-	-	-
826 Rents	LB826	F003	-	-	-	-	-	-	-	-	-	-
Total Storage Operation Labor	LBSO		\$ 82,393	\$ 61,280	\$ 21,113	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<b>Storage Expense Maintenance</b>												
830 Maintenance Super and Eng.	LB830	MSE	-	-	-	-	-	-	-	-	-	-
831 Maintenance of Structures	LB831	F003	-	-	-	-	-	-	-	-	-	-
832 Maintenance of Reservoirs	LB832	F003	907	907	-	-	-	-	-	-	-	-
833 Maintenance of Lines	LB833	F003	-	-	-	-	-	-	-	-	-	-
834 Main of Compressor Station Equipment	LB834	F004	9,527	-	9,527	-	-	-	-	-	-	-
835 Main of Meas and Reg Sta. Equip	LB835	F003	483	483	-	-	-	-	-	-	-	-
836 Main of Purification Equip	LB836	F004	-	-	-	-	-	-	-	-	-	-
837 Main of Other Equipment	LB837	F003	-	-	-	-	-	-	-	-	-	-
Total Maintenance Labor	LBSM		\$ 10,917	\$ 1,390	\$ 9,527	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Storage Labor	LBS		\$ 93,310	\$ 62,670	\$ 30,640	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
<u>Labor Expenses</u>							
<b>Production Expenses</b>							
<b>Operation &amp; Maintenance</b>							
753 Wells and Gathering	LB 753	F006	-	-	-	-	-
754 Compressor Station	LB754	F006	-	-	-	-	-
764 Maintenance of Wells and Gathering	LB764	F006	-	-	-	-	-
765 Maintenance of Compressor Station	LB765	F006	-	-	-	-	-
Total Production Operation & Maintenance Expenses			-	-	-	-	-
807-813 Procurement Expenses	LB807	D/MCM	-	-	-	-	-
<b>Storage Expenses</b>							
<b>Operation</b>							
814 Operations Supervision and Engineer	LB814	OSE	-	-	-	-	-
815 Maps and Records	LB815	F003	-	-	-	-	-
816 Well Expenses	LB816	F003	-	-	-	-	-
817 Lines Expenses	LB817	F003	-	-	-	-	-
818 Compressor Station Exp - Payroll	LB818	F004	-	-	-	-	-
819 Compressor Station Fuel and Power	LB819	F004	-	-	-	-	-
820 Measurement and Regulator Station	LB820	F003	-	-	-	-	-
821 Purification of Natural Gas	LB821	F004	-	-	-	-	-
823 Gas losses	LB823	F004	-	-	-	-	-
824 Other Expenses	LB824	F004	-	-	-	-	-
825 Storage Well Royalties	LB825	F003	-	-	-	-	-
826 Rents	LB826	F003	-	-	-	-	-
Total Storage Operation Labor	LBSO		\$ -	\$ -	\$ -	\$ -	\$ -
<b>Storage Expense</b>							
<b>Maintenance</b>							
830 Maintenance Super and Eng.	LB830	MSE	-	-	-	-	-
831 Maintenance of Structures	LB831	F003	-	-	-	-	-
832 Maintenance of Reservoirs	LB832	F003	-	-	-	-	-
833 Maintenance of Lines	LB833	F003	-	-	-	-	-
834 Main of Compressor Station Equipment	LB834	F004	-	-	-	-	-
835 Main of Meas and Reg. Sta. Equip	LB835	F003	-	-	-	-	-
836 Main of Purification Equip	LB836	F004	-	-	-	-	-
837 Main of Other Equipment	LB837	F003	-	-	-	-	-
Total Maintenance Labor	LBSM		\$ -	\$ -	\$ -	\$ -	\$ -
Total Storage Labor	LBS		-	-	-	-	-

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand
<b>Labor Expenses (Continued)</b>										
Transmission										
850-867	LB850	F005	\$ -	-	-	-	-	-	-	-
<b>Distribution Expenses</b>										
Operation										
870	LB870	DOES	\$ -	-	-	-	-	-	-	-
871	LB871	F007	-	-	-	-	-	-	-	-
872	LB872	F007	-	-	-	-	-	-	-	-
873	LB873	F007	-	-	-	-	-	-	-	-
874.01	LB874.01	CADAL	-	-	-	-	-	-	-	-
874.02	LB874.02	F009	-	-	-	-	-	-	-	-
874.03	LB874.03	F010	-	-	-	-	-	-	-	-
874.04	LB874.04	CADAL	-	-	-	-	-	-	-	-
874.05	LB874.05	F010	-	-	-	-	-	-	-	-
874.06	LB874.06	F009	-	-	-	-	-	-	-	-
874.07	LB874.07	F009	-	-	-	-	-	-	-	-
874.08	LB874.08	F007	-	-	-	-	-	-	-	-
874.09	LB874.09	F009	-	-	-	-	-	-	-	-
874.1	LB874.10	F009	-	-	-	-	-	-	-	-
875	LB875	F008	-	-	-	-	-	-	-	-
876	LB876	F011	-	-	-	-	-	-	-	-
877	LB877	F008	-	-	-	-	-	-	-	-
878	LB878	F011	-	-	-	-	-	-	-	-
879	LB879	F011	-	-	-	-	-	-	-	-
880	LB880	PTDSUB	-	-	-	-	-	-	-	-
881	LB881	PTDSUB	-	-	-	-	-	-	-	-
Total Operations Distribution Labor	LBDO		\$ -	-	-	-	-	-	\$ -	-
Total Operations Transmission and Distribution Labor	LBTD0		\$ 63,035	-	-	-	63,035	-	\$ -	-



Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
<b>Labor Expenses (Continued)</b>							
Transmission							
850-867 Transmission Expenses	LB850	F005	-	-	-	-	-
<b>Distribution Expenses</b>							
Operation							
870 Operation Supr and Engr	LB870	DOES	-	-	-	-	-
871 Dist Load Dispatching	LB871	F007	-	-	-	-	-
872 Compr. Station Labor and Exp.	LB872	F007	-	-	-	-	-
873 Compr. Station Fuel and Power	LB873	F007	-	-	-	-	-
874.01 Other Mains/Serv. Expenses	LB874.01	CADAL	-	-	-	-	-
874.02 Leak Survey-Mains	LB874.02	F009	-	-	-	-	-
874.03 Leak Survey - Service	LB874.03	F010	-	-	-	-	-
874.04 Locate Main per Request	LB874.04	CADAL	-	-	-	-	-
874.05 Check Stop Box Access	LB874.05	F010	-	-	-	-	-
874.06 Patrolling Mains	LB874.06	F009	-	-	-	-	-
874.07 Check/Grease Valves	LB874.07	F009	-	-	-	-	-
874.08 Opr. Odor Equipment	LB874.08	F009	-	-	-	-	-
874.09 Locate and Inspect Valve Boxes	LB874.09	F009	-	-	-	-	-
874.1 Cut Grass - Right of Way	LB874.10	F009	-	-	-	-	-
875 Meas and Reg Station Exp. - General	LB875	F008	-	-	-	-	-
876 Meas and Reg Station Exp. - Industrial	LB876	F011	-	-	-	-	-
877 Meas and Reg Station Exp. - City Gate	LB877	F008	-	-	-	-	-
878 Meter and House Reg. Expense	LB878	F011	-	-	-	-	-
879 Customer Installation Expense	LB879	F011	-	-	-	-	-
880 Other Expenses	LB880	PTDSUB	-	-	-	-	-
881 Rents	LB881	PTDSUB	-	-	-	-	-
Total Operations Distribution Labor	LBDO		\$	\$	\$	\$	
Total Operations Transmission and Distribution Labor	LBTDO		\$	\$	\$	\$	

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand
<b>Labor Expenses (Continued)</b>										
<b>Maintenance Expense -- Transmission and Distribution</b>										
885 Maintenance Supr and Engr	LB885	DMES	\$ -	-	-	-	-	-	-	-
886 Maintenance Structures	LB886	F008	-	-	-	-	-	-	-	-
887 Maintenance Mains	LB887	F009	86,672	-	-	-	-	-	-	37,668
888 Maintenance Comp. Station Equip.	LB888	F007	-	-	-	-	-	-	-	-
889 Maintenance Meas and Reg. General	LB889	F008	-	-	-	-	-	-	-	-
890 Maintenance Meas and Reg. - Industrial	LB890	F011	-	-	-	-	-	-	-	-
891 Maintenance Meas and Reg.-City Gate	LB891	F008	-	-	-	-	-	-	-	-
892 Maintenance Services	LB892	F010	-	-	-	-	-	-	-	-
893 Maintenance Meters and House Reg.	LB893	F011	16,313	-	-	-	-	-	-	-
894 Maintenance Other Equipment	LB894	PTDSUB	9,805	-	-	-	-	239	2,812	-
898 Maintenance Transportation Equip	LB898	PTDSUB	-	-	-	-	-	-	-	-
900 Trans & Distribution Expenses	LB900	TDSUB	2,560,526	-	-	907,004	-	40,238	474,260	-
Total Maintenance Labor	LBDM		\$ 2,673,316	\$ -	\$ -	\$ 907,004	\$ -	\$ 40,476	\$ 474,260	\$ 514,740
Total Transmission & Distribution Labor	LBTD		\$ 2,748,985	\$ -	\$ -	\$ 907,004	\$ 75,669	\$ 40,476	\$ 514,740	\$ 514,740
<b>Customer Accounts Expense</b>										
901 Supervision	LB901	F012	\$ -	-	-	-	-	-	-	-
902 Meter Reading	LB902	F012	-	-	-	-	-	-	-	-
903 Customer Records and Collections	LB903	F012	404,578	-	-	-	-	-	-	-
904 Uncollectible Accounts	LB904	F012	-	-	-	-	-	-	-	-
905 Misc. Cust Account Expenses	LB905	F012	-	-	-	-	-	-	-	-
Total Customer Accounts Labor	LBCA		\$ 404,578	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<b>Customer Service Expenses</b>										
907-910 Customer Service	LB907	F013	\$ -	-	-	-	-	-	-	-
Sales Expenses										
911-916 Sales Expenses	LB911	F013	\$ -	-	-	-	-	-	-	-

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains		Services		Meters		Customer Accounts		Customer Service Expense	
			Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer
<b>Labor Expenses (Continued)</b>												
<b>Maintenance Expense -- Transmission and Distribution</b>												
865	Maintenance Supr. and Engr											
866	Maintenance Structures											
867	Maintenance Mains			49,004								
868	Maintenance Comp. Station Equip.											
869	Maintenance Meas and Reg. General											
890	Maintenance Meas and Reg. - Industrial											
891	Maintenance Meas and Reg. - City Gate											
892	Maintenance Services											
893	Maintenance Meters and House Reg.							16,313				
894	Maintenance Other Equipment			3,659		1,344		1,752				
898	Maintenance Transportation Equip											
900	Trans & Distribution Expenses			616,996		226,583		295,445				
	Total Maintenance Labor			669,659	\$	227,927	\$	313,510	\$		\$	
	Total Transmission & Distribution Labor			669,659	\$	227,927	\$	313,510	\$		\$	
<b>Customer Accounts Expense</b>												
901	Supervision											
902	Meter Reading											
903	Customer Records and Collections								404,578			
904	Uncollectible Accounts											
905	Misc. Cust. Account Expenses											
	Total Customer Accounts Labor				\$		\$		\$	404,578	\$	
<b>Customer Service Expenses</b>												
907-910	Customer Service											
	Sales Expenses											
911-916	Sales Expenses											

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	
<b>Labor Expenses (Continued)</b>											
<b>Administrative &amp; General</b>											
920 Admin and General Salaries	LB920	LBSUB	2,482,184	47,910	23,424	693,391	57,848	-	30,944	393,510	
921 Office Supplies and Expense	LB921	LBSUB	-	-	-	-	-	-	-	-	
922 Admin. Expenses Transferred	LB922	LBSUB	-	-	-	-	-	-	-	-	
923 Outside Services Employed	LB923	OMSUB	-	-	-	-	-	-	-	-	
924 Property Insurance	LB924	PTT	-	-	-	-	-	-	-	-	
925 Injuries and Damages	LB925	PTT	-	-	-	-	-	-	-	-	
926 Employee Pensions and Benefits	LB926	LBSUB	1,036,705	20,010	9,783	289,600	24,161	-	12,924	164,353	
927 Franchise Requirement	LB927	PTT	-	-	-	-	-	-	-	-	
928 Regulatory Commission Fee	LB928	PTT	-	-	-	-	-	-	-	-	
929 Duplicate Charges -Credit	LB929	PTT	-	-	-	-	-	-	-	-	
930.1 General Advertising Expense	LB930.1	PTT	-	-	-	-	-	-	-	-	
930.2 Misc. General Expense	LB930.2	OMSUB	-	-	-	-	-	-	-	-	
931 Rents	LB931	PTT	-	-	-	-	-	-	-	-	
935 Maintenance of General Plant	LB935	PT389	-	-	-	-	-	-	-	-	
Total Administrative and General Labor	LBAG		\$ 3,518,889	\$ 67,920	\$ 33,207	\$ 982,991	\$ 82,008	\$ -	\$ 43,867	\$ 557,863	
Total Labor Expense	LBTOT		\$ 6,765,762	\$ 130,590	\$ 63,847	\$ 1,889,995	\$ 157,677	\$ -	\$ 84,344	\$ 1,072,603	

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains		Services		Meters		Customer Accounts		Customer Service Expense	
			Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer
<b>Labor Expenses (Continued)</b>												
<b>Administrative &amp; General</b>												
920 Admin and General Salaries	LB920	LBSUB	511,944	-	174,247	-	239,674	-	309,294	-	-	-
921 Office Supplies and Expense	LB921	LBSUB	-	-	-	-	-	-	-	-	-	-
922 Admin. Expenses Transferred	LB922	LBSUB	-	-	-	-	-	-	-	-	-	-
923 Outside Services Employed	LB923	OMSUB	-	-	-	-	-	-	-	-	-	-
924 Property Insurance	LB924	PTT	-	-	-	-	-	-	-	-	-	-
925 Injuries and Damages	LB925	PTT	-	-	-	-	-	-	-	-	-	-
926 Employee Pensions and Benefits	LB926	LBSUB	213,818	-	72,776	-	100,102	-	129,179	-	-	-
927 Franchise Requirement	LB927	PTT	-	-	-	-	-	-	-	-	-	-
928 Regulatory Commission Fee	LB928	PTT	-	-	-	-	-	-	-	-	-	-
929 Duplicate Charges -Dredit	LB929	PTT	-	-	-	-	-	-	-	-	-	-
930.1 General Advertising Expense	LB930.1	PTT	-	-	-	-	-	-	-	-	-	-
930.2 Misc. General Expense	LB930.2	OMSUB	-	-	-	-	-	-	-	-	-	-
931 Rents	LB931	PTT	-	-	-	-	-	-	-	-	-	-
935 Maintenance of General Plant	LB935	PT389	-	-	-	-	-	-	-	-	-	-
Total Administrative and General Labor	LBAG		\$ 725,761	\$	\$ 247,022	\$	\$ 339,775	\$	\$ 438,473	\$	\$	\$
Total Labor Expense	LBTOT		\$ 1,395,420	\$	\$ 474,949	\$	\$ 653,285	\$	\$ 843,051	\$	\$	\$

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Structures & Equipment Demand	Distribution Commodity	Distribution Mains Demand
<u>Operation &amp; Maintenance Expenses</u>										
<u>Production Expenses</u>										
<u>Operation &amp; Maintenance</u>										
753 Wells and Gathering	OM753	F006	8,855	-	-	-	8,855	-	-	-
754 Compressor Station	OM754	F006	121,888	-	-	-	121,888	-	-	-
764 Maintenance of Wells and Gathering	OM764	F006	316	-	-	-	316	-	-	-
765 Maintenance of Compressor Station	OM765	F006	33,501	-	-	-	33,501	-	-	-
Total Production Operation & Maintenance Expenses			164,560	-	-	-	164,560	-	-	-
807-813 Procurement Expenses	OM807	DMCM	-	-	-	-	-	-	-	-
<u>Storage Expenses</u>										
<u>Operation</u>										
814 Operations Supervision and Engineer	OM814	OSE	-	-	-	-	-	-	-	-
815 Maps and Records	OM815	F003	-	-	-	-	-	-	-	-
816 Well Expenses	OM816	F003	61,646	-	-	-	-	-	-	-
817 Lines Expenses	OM817	F003	-	-	-	-	-	-	-	-
818 Compressor Station Exp - Payroll	OM818	F004	46,077	-	46,077	-	-	-	-	-
819 Compressor Station Fuel and Power	OM819	F004	-	-	-	-	-	-	-	-
820 Measurement and Regulator Station	OM820	F003	-	-	-	-	-	-	-	-
821 Purification of Natural Gas	OM821	F004	103,330	-	103,330	-	-	-	-	-
823 Gas losses	OM823	F004	-	-	-	-	-	-	-	-
824 Other Expenses	OM824	F004	1,808	-	1,808	-	-	-	-	-
825 Storage Well Royalties	OM825	F003	56,371	-	-	-	-	-	-	-
826 Rents	OM826	F003	-	-	-	-	-	-	-	-
Total Operation Expenses	OM/OE		269,232	118,017	151,215	-	-	-	-	-
<u>Storage Expense Maintenance</u>										
830 Maintenance Super and Eng.	OM830	MSE	-	-	-	-	-	-	-	-
831 Maintenance of Structures	OM831	F003	2,649	2,649	-	-	-	-	-	-
832 Maintenance of Reservoirs	OM832	F003	44,339	44,339	-	-	-	-	-	-
833 Maintenance of Lines	OM833	F003	-	-	-	-	-	-	-	-
834 Main of Compressor Station Equipment	OM834	F004	35,829	-	35,829	-	-	-	-	-
835 Main of Meas and Reg Sta. Equip	OM835	F003	2,218	2,218	-	-	-	-	-	-
836 Main of Purification Equip	OM836	F004	-	-	-	-	-	-	-	-
837 Main of Other Equipment	OM837	F003	2,303	2,303	-	-	-	-	-	-
Total Maintenance Expense	OM/ME		87,338	51,509	35,829	-	-	-	-	-
Total Storage Expense	O/S		356,570	169,526	187,044	-	-	-	-	-

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains		Services		Meters		Customer Accounts		Customer Service	
			Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer
<b>Operation &amp; Maintenance Expenses</b>												
<b>Production Expenses</b>												
<b>Operation &amp; Maintenance</b>												
753 Wells and Gathering	OM753	F006	-	-	-	-	-	-	-	-	-	-
754 Compressor Station	OM754	F006	-	-	-	-	-	-	-	-	-	-
764 Maintenance of Wells and Gathering	OM764	F006	-	-	-	-	-	-	-	-	-	-
765 Maintenance of Compressor Station	OM765	F006	-	-	-	-	-	-	-	-	-	-
Total Production Operation & Maintenance Expenses												
807-813 Procurement Expenses	OM807	DMCM	-	-	-	-	-	-	-	-	-	-
<b>Storage Expenses</b>												
<b>Operation</b>												
814 Operations Supervision and Engineer	OM814	OSE	-	-	-	-	-	-	-	-	-	-
815 Maps and Records	OM815	F003	-	-	-	-	-	-	-	-	-	-
816 Well Expenses	OM816	F003	-	-	-	-	-	-	-	-	-	-
817 Lines Expenses	OM817	F003	-	-	-	-	-	-	-	-	-	-
818 Compressor Station Exp - Payroll	OM818	F004	-	-	-	-	-	-	-	-	-	-
819 Compressor Station Fuel and Power	OM819	F004	-	-	-	-	-	-	-	-	-	-
820 Measurement and Regulator Station	OM820	F003	-	-	-	-	-	-	-	-	-	-
821 Purification of Natural Gas	OM821	F004	-	-	-	-	-	-	-	-	-	-
823 Gas losses	OM823	F004	-	-	-	-	-	-	-	-	-	-
824 Other Expenses	OM824	F004	-	-	-	-	-	-	-	-	-	-
825 Storage Well Royalties	OM825	F003	-	-	-	-	-	-	-	-	-	-
826 Rents	OM826	F003	-	-	-	-	-	-	-	-	-	-
Total Operation Expenses												
	OMOE		\$	-	\$	-	\$	-	\$	-	\$	-
<b>Storage Expense</b>												
<b>Maintenance</b>												
830 Maintenance Super and Eng.	OM830	MSE	-	-	-	-	-	-	-	-	-	-
831 Maintenance of Structures	OM831	F003	-	-	-	-	-	-	-	-	-	-
832 Maintenance of Reservoirs	OM832	F003	-	-	-	-	-	-	-	-	-	-
833 Maintenance of Lines	OM833	F003	-	-	-	-	-	-	-	-	-	-
834 Main of Compressor Station Equipment	OM834	F004	-	-	-	-	-	-	-	-	-	-
835 Main of Meas and Reg Sta. Equip	OM835	F003	-	-	-	-	-	-	-	-	-	-
836 Main of Purification Equip	OM836	F004	-	-	-	-	-	-	-	-	-	-
837 Main of Other Equipment	OM837	F003	-	-	-	-	-	-	-	-	-	-
Total Maintenance Expense												
	OMME		\$	-	\$	-	\$	-	\$	-	\$	-
Total Storage Expense												
	OMS			-		-		-		-		-

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand
<b>Operation &amp; Maintenance Expenses (Continued)</b>										
Transmission										
850-867 Transmission Expenses	OM850	F005	\$ 66,285	-	-	66,285	-	-	-	-
<b>Distribution Expenses</b>										
Operation										
870 Operation Supr and Engr	OM870	DOES	\$ -	-	-	-	-	-	-	-
871 Dist Load Dispatching	OM871	F007	58,165	-	-	-	-	58,165	-	-
872 Compr. Station Labor and Exp.	OM872	F007	-	-	-	-	-	-	-	-
873 Compr. Station Fuel and Power	OM873	F007	-	-	-	-	-	-	-	-
874.01 Other Mains/Serv. Expenses	OM874.01	CADAL	-	-	-	-	-	-	-	-
874.02 Leak Survey-Mains	OM874.02	F009	-	-	-	-	-	-	-	-
874.03 Leak Survey - Service	OM874.03	F010	-	-	-	-	-	-	-	-
874.04 Locate Main per Request	OM874.04	CADAL	-	-	-	-	-	-	-	-
874.05 Check Stop Box Access	OM874.05	F010	-	-	-	-	-	-	-	-
874.06 Patrolling Mains	OM874.06	F009	-	-	-	-	-	-	-	-
874.07 Check/Grease Valves	OM874.07	F009	-	-	-	-	-	-	-	-
874.08 Opr. Odor Equipment	OM874.08	F007	-	-	-	-	-	-	-	-
874.09 Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-	-	-	-	-
874.10 Cut Grass - Right of Way	OM874.10	F009	-	-	-	-	-	-	-	-
875 Meas and Reg Station Exp. - General	OM875	F008	-	-	-	-	-	-	-	-
876 Meas and Reg Station Exp. - Industrial	OM876	F011	-	-	-	-	-	-	-	-
877 Meas and Reg Station Exp. - City Gate	OM877	F008	-	-	-	-	-	-	-	-
878 Meter and House Reg. Expense	OM878	F011	-	-	-	-	-	-	-	-
879 Customer Installation Expense	OM879	F011	349,553	-	-	-	-	-	8,506	100,258
880 Other Expenses	OM880	PTDSUB	17,394	-	-	-	-	-	423	4,989
881 Rents	OM881	PTDSUB	-	-	-	-	-	-	-	-
Total Operations Distribution Expense	OMDO		\$ 425,112	-	-	-	-	58,165	8,930	105,247
Total Transmission and Distribution Oper Exp	OMTDO		\$ 622,140	\$ -	\$ -	\$ 66,285	\$ 130,743	\$ 58,165	\$ 8,930	\$ 105,247



DELTA NATURAL GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains		Services		Meters		Customer Accounts		Customer Service	
			Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Expense	Customer
<b>Operation &amp; Maintenance Expenses (Continued)</b>												
Transmission												
850-867 Transmission Expenses	OM850	F005	-	-	-	-	-	-	-	-	-	-
<b>Distribution Expenses</b>												
Operation												
870 Operation Supr and Engr	OM870	DOES	-	-	-	-	-	-	-	-	-	-
871 Dist Load Dispatching	OM871	F007	-	-	-	-	-	-	-	-	-	-
872 Compr. Station Labor and Exp.	OM872	F007	-	-	-	-	-	-	-	-	-	-
873 Compr. Station Fuel and Power	OM873	F007	-	-	-	-	-	-	-	-	-	-
874.01 Other Mains/Serv. Expenses	OM874.01	CADAL	-	-	-	-	-	-	-	-	-	-
874.02 Leak Survey-Mains	OM874.02	F009	-	-	-	-	-	-	-	-	-	-
874.03 Leak Survey - Service	OM874.03	F010	-	-	-	-	-	-	-	-	-	-
874.04 Locate Main per Request	OM874.04	CADAL	-	-	-	-	-	-	-	-	-	-
874.05 Check Stop Box Access	OM874.05	F010	-	-	-	-	-	-	-	-	-	-
874.06 Patrolling Mains	OM874.06	F009	-	-	-	-	-	-	-	-	-	-
874.07 Check/Grease Valves	OM874.07	F009	-	-	-	-	-	-	-	-	-	-
874.08 Opr. Odor Equipment	OM874.08	F007	-	-	-	-	-	-	-	-	-	-
874.09 Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-	-	-	-	-	-	-
874.1 Cut Grass - Right of Way	OM874.10	F009	-	-	-	-	-	-	-	-	-	-
875 Meas and Reg Station Exp - General	OM875	F008	-	-	-	-	-	-	-	-	-	-
876 Meas and Reg Station Exp - Industrial	OM876	F011	-	-	-	-	-	-	-	-	-	-
877 Meas and Reg Station Exp - City Gate	OM877	F008	-	-	-	-	-	-	-	-	-	-
878 Meter and House Reg. Expense	OM878	F011	-	-	-	-	-	-	-	-	-	-
879 Customer Installation Expense	OM879	F011	-	-	-	-	-	-	-	-	-	-
880 Other Expenses	OM880	PTDSUB	130,432	47,900	62,457	62,457	62,457	62,457	62,457	62,457	62,457	62,457
881 Rents	OM881	PTDSUB	6,490	2,364	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108
Total Operations Distribution Expense	OMDO		136,923	50,283	65,565	65,565	65,565	65,565	65,565	65,565	65,565	65,565
Total Transmission and Distribution Oper Exp	OMTDO		\$ 136,923	\$ 50,283	\$ 65,565	\$ 65,565	\$ 65,565	\$ 65,565	\$ 65,565	\$ 65,565	\$ 65,565	\$ 65,565

DELTA NA - GAS COMPANY  
 Cost of Service Study  
 12 Months Ended December 31, 2006

Second PS Request # 46

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Structures & Equipment Demand	Distribution Commodity	Distribution Mains Demand
<b>Operation &amp; Maintenance Expenses (Continued)</b>										
Maintenance Expense -- Transmission and Distribution										
885	Maintenance Supr and Engr	DMES	-	-	-	-	-	-	-	-
886	Maintenance Structures	F008	-	-	-	-	-	-	-	-
887	Maintenance Mains	F009	150,379	-	-	-	-	-	-	-
888	Maintenance Comp. Station Equip.	F007	-	-	-	-	-	-	-	65,355
889	Maintenance Meas and Reg. General	F008	7,505	-	-	-	-	7,505	-	-
890	Maintenance Meas and Reg. - Industrial	F011	-	-	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	F008	-	-	-	-	-	-	-	-
892	Maintenance Services	OM891	-	-	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	F010	59,307	-	-	-	-	-	-	-
894	Maintenance Other Equipment	PTDSUB	112,086	-	-	-	-	2,728	-	32,148
898	Maintenance Transportation Equip	PTDSUB	45,916	-	-	-	-	1,117	-	13,170
900	Trans & Distribution Expenses	TDSUB	3,344,534	-	-	1,184,720	-	52,558	-	619,473
Total Maintenance Expenses	OMME		3,719,727	\$ -	\$ -	1,184,720	\$ -	63,908	\$ -	730,146
Total Transmission & Distribution Expenses	OMDE		4,375,684	\$ -	\$ -	1,251,005	\$ 164,560	72,838	\$ 58,165	835,393
Customer Accounts Expense										
901	Supervision	F012	-	-	-	-	-	-	-	-
902	Meter Reading	F012	-	-	-	-	-	-	-	-
903	Customer Records and Collections	F012	628,360	-	-	-	-	-	-	-
904	Uncollectible Accounts	OM904	484,710	-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	F012	-	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		1,113,070	\$ -	\$ -	-	\$ -	-	\$ -	-
Customer Service Expenses										
907-910	Customer Service	F013	-	-	-	-	-	-	-	-
Sales Expenses										
911-916	Sales Expenses	F013	2,264	-	-	-	-	-	-	-

DELTA N/ L GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains		Services		Meters		Customer Accounts		Customer Service	
			Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Expense	Customer
<b>Operation &amp; Maintenance Expenses (Continued)</b>												
<b>Maintenance Expense -- Transmission and Distribution</b>												
885	Maintenance Supr and Engr	DMES	-	-	-	-	-	-	-	-	-	-
886	Maintenance Structures	F008	-	-	-	-	-	-	-	-	-	-
887	Maintenance Mains	F009	85,024	-	-	-	-	-	-	-	-	-
888	Maintenance Comp. Station Equip.	F007	-	-	-	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	F008	-	-	-	-	-	-	-	-	-	-
890	Maintenance Meas and Reg. - Industrial	F011	-	-	-	-	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	F008	-	-	-	-	-	-	-	-	-	-
892	Maintenance Services	F010	-	-	-	-	59,307	-	-	-	-	-
893	Maintenance Meters and House Reg.	F011	-	-	-	15,359	20,027	-	-	-	-	-
894	Maintenance Other Equipment	PTDSUB	41,824	-	6,292	8,204	-	-	-	-	-	-
898	Maintenance Transportation Equip	PTDSUB	17,133	-	295,961	385,908	-	-	-	-	-	-
900	Trans & Distribution Expenses	TDSUB	805,914	-	-	-	473,446	-	-	-	-	-
	Total Maintenance Expenses	OMME	\$ 949,895	\$ -	\$ 317,612	\$ 473,446	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	Total Transmission & Distribution Expenses	OMDE	\$ 1,086,818	\$ -	\$ 367,895	\$ 539,011	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<b>Customer Accounts Expense</b>												
901	Supervision	F012	-	-	-	-	-	-	-	-	-	-
902	Meter Reading	F012	-	-	-	-	-	628,360	-	-	-	-
903	Customer Records and Collections	F012	-	-	-	-	-	484,710	-	-	-	-
904	Uncollectible Accounts	F012	-	-	-	-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	F012	-	-	-	-	-	-	-	-	-	-
	Total Customer Accounts Expense	OMCA	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,113,070	\$ -	\$ -	\$ -	\$ -
<b>Customer Service Expenses</b>												
907-910	Customer Service	F013	-	-	-	-	-	-	-	-	-	-
911-916	Sales Expenses	OM911	-	-	-	-	-	-	-	-	-	2,264
	Sales Expenses	F013	-	-	-	-	-	-	-	-	-	2,264

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand
<b>Operation &amp; Maintenance Expenses (Continued)</b>										
<b>Administrative &amp; General</b>										
920 Admin and General Salaries	OM920	LBSUB	\$ 2,576,284	49,727	24,312	719,677	60,041	-	32,117	408,428
921 Office Supplies and Expense	OM921	LBSUB	579,830	11,192	5,472	161,974	13,513	-	7,228	91,923
922 Admin. Expenses Transferred	OM922	LBSUB	(3,036,569)	(58,611)	(28,655)	(848,256)	(70,768)	-	(37,855)	(481,399)
923 Outside Services Employed	OM923	OMSUB	657,984	19,075	21,047	140,766	18,517	6,545	8,196	94,000
924 Property Insurance	OM924	PTT	786,124	77,118	-	255,578	-	-	11,021	130,128
925 Injuries and Damages	OM925	PTT	-	-	-	-	-	-	-	-
926 Employee Pensions and Benefits	OM926	LBSUB	3,181,757	61,413	30,026	888,814	74,151	-	39,665	504,416
927 Franchise Requirement	OM927	PTT	-	-	-	-	-	-	-	-
928 Regulatory Commission Fee	OM928	PTT	163,359	16,025	-	53,110	-	-	2,290	27,041
929 Duplicate Charges -Dredit	OM929	PTT	-	-	-	-	-	-	-	-
930.1 General Advertising Expense	OM930.1	PTT	-	-	-	-	-	-	-	-
930.2 Misc. General Expense	OM930.2	OMSUB	562,597	16,310	17,996	120,359	15,832	5,596	7,008	80,373
931 Rents	OM931	PTT	-	-	-	-	-	-	-	-
932 Maintenance of General Plant	OM932	PT389	183,395	14,231	-	59,922	-	-	2,658	31,332
Total Administrative and General Expense	OMAGT		\$ 5,654,761	\$ 206,481	\$ 70,196	\$ 1,551,944	\$ 111,286	\$ 12,141	\$ 72,329	\$ 886,243
Total Operation & Maintenance Expense	OMT		\$ 11,502,349	\$ 376,007	\$ 257,240	\$ 2,802,949	\$ 275,846	\$ 70,306	\$ 145,166	\$ 1,721,636

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains		Services		Meters		Customer Accounts		Customer Service	
			Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Expense	Customer
<b>Operation &amp; Maintenance Expenses (Continued)</b>												
<b>Administrative &amp; General</b>												
920	Admin and General Salaries			531,352	180,852		248,760		321,019			
921	Office Supplies and Expense	LBSUB		119,588	40,703		55,987		72,250			
922	Admin. Expenses Transferred	LBSUB		(626,284)	(213,164)		(293,204)		(378,373)			
923	Outside Services Employed	OMSUB		122,291	41,396		60,651		125,245			255
924	Property Insurance	PTT		169,292	62,053		80,924					
925	Injuries and Damages	PTT										
926	Employee Pensions and Benefits	LBSUB		656,229	223,356		307,223		396,464			
927	Franchise Requirement	PTT										
928	Regulatory Commission Fee	PTT		35,179	12,897		16,816					
929	Duplicate Charges -Credit	PTT										
930.1	General Advertising Expense	PTT										
930.2	Misc. General Expense	OMSUB		104,563	35,395		51,858		107,089			218
931	Rents	PTT										
932	Maintenance of General Plant	PT389		40,762	14,969		19,519					
	Total Administrative and General Expense	OMAGT	\$	1,152,972	\$ 398,469	\$	548,534	\$	643,694	\$	473	
	Total Operation & Maintenance Expense	OMT	\$	2,239,790	\$ 766,364	\$	1,087,545	\$	1,756,764	\$	2,737	

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	
<b>Depreciation Expenses</b>											
Underground Storage											
350-357	DP350	F003	232,682	232,682	-	-	-	-	-	-	
Transmission											
365-371	DP365	F005	1,122,524	-	-	1,122,524	-	-	-	-	
Distribution											
374	DP374	F008	-	-	-	-	-	-	-	-	
375	DP375	F008	3,300	-	-	-	-	-	3,300	-	
376	DP376	F009	1,516,595	-	-	-	-	-	-	-	
378	DP378	F008	40,376	-	-	-	-	-	40,376	659,112	
379	DP379	F008	13,917	-	-	-	-	-	13,917	-	
380	DP380	F010	308,831	-	-	-	-	-	-	-	
381	DP381	F011	196,929	-	-	-	-	-	-	-	
382	DP382	F011	129,421	-	-	-	-	-	-	-	
383	DP383	F011	115,137	-	-	-	-	-	-	-	
384	DP384	F011	-	-	-	-	-	-	-	-	
385	DP385	F011	35,864	-	-	-	-	-	-	-	
387	DP387	F011	-	-	-	-	-	-	-	-	
	PTSUB		-	-	-	-	-	-	-	-	
Total Distribution			2,360,370	\$ -	\$ -	\$ -	\$ -	\$ -	57,593	659,112	
117	DP117	F003	-	-	-	-	-	-	-	-	
301-303	DP301	PTSUB	-	-	-	-	-	-	-	-	
389-399	DP389	PTSUB	531,163	41,218	-	173,551	-	-	7,699	90,747	
Common Utility Plant	DPCP	PTSUB	-	-	-	-	-	-	-	-	
Amortization of Gas Plant	AMORT	PTSUB	(12,000)	(931)	-	(3,921)	-	-	(174)	(2,050)	
Accretion Expense	ACCRTN	PTSUB	-	-	-	-	-	-	-	-	
Total Depreciation Expense	DEPREX		4,234,739	\$ 272,969	\$ -	\$ 1,292,154	\$ -	\$ -	65,118	747,809	

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
<b>Depreciation Expenses</b>							
Underground Storage	DP350	F003	-	-	-	-	-
350-357 Underground Storage Plant							
Transmission	DP365	F005	-	-	-	-	-
365-371 Transmission Plant							
Distribution	DP374	F008	-	-	-	-	-
374 Land & Land Rights							
375 Structures & Improvements	DP375	F008	-	-	-	-	-
376 Mains	DP376	F009	857,483	-	-	-	-
378 Meas & Reg Station Eq.-Gen	DP378	F008	-	-	-	-	-
379 Meas & Reg Station Eq.-City Gate	DP379	F008	-	-	-	-	-
380 Services	DP380	F010	-	308,831	-	-	-
381 Meters	DP381	F011	-	-	196,929	-	-
382 Meter Installations	DP382	F011	-	-	129,421	-	-
383 House Regulators	DP383	F011	-	-	115,137	-	-
384 House Regulator Installations	DP384	F011	-	-	-	-	-
385 Industrial Meas & Reg Equipment	DP385	F011	-	-	35,864	-	-
387 Other Equipment	DP387	F011	-	-	-	-	-
		PTSUB	-	-	-	-	-
Total Distribution			\$ 857,483	\$ 308,831	\$ 477,351	\$ -	\$ -
117 Gas Stored Underground	DP117	F003	-	-	-	-	-
301-303 Intangible Plant	DP301	PTSUB	-	-	-	-	-
389-399 General Plant	DP389	PTSUB	118,059	43,356	56,532	-	-
Common Utility Plant	DP389	PTSUB	-	-	-	-	-
Amortization of Gas Plant	AMORT	PTSUB	(2,667)	(979)	(1,277)	-	-
Accretion Expense	ACCRTN	PTSUB	-	-	-	-	-
Total Depreciation Expense	DEPREX		\$ 972,875	\$ 351,207	\$ 532,606	\$ -	\$ -

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage		Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand		
				Demand	Commodity				Demand	Demand	
<u>Taxes Other Than Income Taxes</u>											
Licenses & Privilege Fee	OTRE	PTT	\$ 5,432	533	-	1,766	-	-	76	899	
Property Taxes	OTPP	PTT	1,221,140	119,792	-	397,007	-	-	17,120	202,136	
Payroll Taxes	OTUN	LBTOT	540,909	10,440	5,104	151,101	12,606	-	6,743	85,752	
Total Taxes Other Than Income Taxes	OTT		\$ 1,767,481	\$ 130,765	\$ 5,104	\$ 549,874	\$ 12,606	\$ -	\$ 23,940	\$ 288,788	
Interest on Long Term Debt	INT	PTT	\$ 4,967,706	487,325	-	1,615,059	-	-	69,647	822,308	



Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
<b>Taxes Other Than Income Taxes</b>							
Liscense & Privilege Fee	OTRE	PTT	1,170	429	559	-	-
Property Taxes	OTPP	PTT	262,972	96,406	125,705	-	-
Payroll Taxes	OTUN	LBTOT	111,561	37,971	52,229	67,400	-
Total Taxes Other Than Income Taxes	OTT	\$	375,703 \$	134,806 \$	178,494 \$	67,400 \$	-
Interest on Long Term Debt	INT	PTT	1,069,795	392,190	511,381	-	-

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	
<b>Functional Assignment Vectors</b>											
Gas Supply Demand	F001		1,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	
Gas Supply Commodity	F002		1,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	
Storage Demand	F003		1,000,000	1,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	
Storage Commodity	F004		1,000,000	0,000,000	1,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	
Transmission Demand	F005		1,000,000	0,000,000	0,000,000	1,000,000	0,000,000	0,000,000	0,000,000	0,000,000	
Transmission Commodity	F006		1,000,000	0,000,000	0,000,000	0,000,000	1,000,000	0,000,000	0,000,000	0,000,000	
Distribution Expense Commodity	F007		1,000,000	0,000,000	0,000,000	0,000,000	0,000,000	1,000,000	0,000,000	0,000,000	
Distribution Structures & Equipment	F008		1,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	1,000,000	0,000,000	
Distribution Mains	F009		1,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,434,600	
Services	F010		1,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	
Meters	F011		1,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	
Customer Accounts	F012		1,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	
Customer Service Expense	F013		1,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	0,000,000	
Transmission & Distribution Mains	TDMSUB		\$ 112,861,466	\$ -	\$ -	\$ 51,227,484	\$ -	\$ -	\$ -	\$ 26,786,129	

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains		Services		Meters		Customer Accounts		Customer Service Expense	
			Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer
<b>Functional Assignment Vectors</b>												
Gas Supply Demand	F001		0.000000		0.000000		0.000000		0.000000		0.000000	
Gas Supply Commodity	F002		0.000000		0.000000		0.000000		0.000000		0.000000	
Storage Demand	F003		0.000000		0.000000		0.000000		0.000000		0.000000	
Storage Commodity	F004		0.000000		0.000000		0.000000		0.000000		0.000000	
Transmission Demand	F005		0.000000		0.000000		0.000000		0.000000		0.000000	
Transmission Commodity	F006		0.000000		0.000000		0.000000		0.000000		0.000000	
Distribution Expense Commodity	F007		0.000000		0.000000		0.000000		0.000000		0.000000	
Distribution Structures & Equipment	F008		0.565400		0.000000		0.000000		0.000000		0.000000	
Distribution Mains	F009		0.000000		0.000000		0.000000		0.000000		0.000000	
Services	F010		0.000000		1.000000		0.000000		0.000000		0.000000	
Meters	F011		0.000000		0.000000		1.000000		0.000000		0.000000	
Customer Accounts	F012		0.000000		0.000000		0.000000		1.000000		0.000000	
Customer Service Expense	F013		0.000000		0.000000		0.000000		0.000000		1.000000	
Transmission & Distribution Mains	TDMSUB		34,847,853	\$		\$		\$		\$		\$

DELTA NA GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	
<b>Internally Generated Functional Vectors</b>											
Sub-Total Distribution Plant		PTDSUB	1,000,000	-	-	-	-	-	0,024,335	0,286,618	
Storage-Transmission-Distribution Subtotal		PTSUB	1,000,000	0,077,600	-	0,326,738	-	-	0,014,495	0,170,847	
Total Storage Plant		PTST	1,000,000	1,000,000	-	-	-	-	-	-	
Transmission Plant		PT365	1,000,000	-	-	1,000,000	-	-	-	-	
General Plant		PT389	1,000,000	-	-	0,326,738	-	-	-	-	
Total Distribution Plant		PTDSUB	1,000,000	0,077,600	-	0,326,738	-	-	0,014,495	0,170,847	
Sub-Total CWIP		CWIP	1,000,000	0,016,915	-	0,800,457	-	-	0,024,335	0,286,618	
Total Depreciation Reserve		DEPR	1,000,000	0,083,443	-	0,336,804	-	-	0,003,160	0,060,182	
Storage-Transmission -Distribution Plant Subtotal		PTSUB	1,000,000	0,077,600	-	0,326,738	-	-	0,014,495	0,170,847	
Transmission and Distribution Payroll		LBTD	1,000,000	-	-	0,329,941	-	-	0,014,724	0,187,247	
Transmission and Distribution Mains		TMSUB	1,000,000	-	-	0,453,897	-	-	-	0,237,356	
Storage Operation Expenses Subtotal	OSE		82,393	61,280	21,113	-	-	-	-	-	
Storage Maintenance Expenses Subtotal	MSE		10,917	1,390	9,527	-	-	-	-	-	
Mains & Services	CADAL		74,431,389	-	-	-	-	-	-	26,786,129	
Demand/Commodity Percent of Purchased Gas Cost	DMCM		1,000,000	-	-	-	-	-	-	-	
Distribution Operation Expenses Subtotal	DOES		112,790	-	-	-	-	-	239	40,480	
Distribution Maintenance Expenses Subtotal	DMES		3,246,873	62,670	30,640	907,004	75,669	-	40,476	514,740	
Subtotal Labor Expenses	LBSUB		5,847,588	169,526	187,044	1,251,005	164,560	58,165	72,838	835,393	
Subtotal O&M Expenses	OMSUB										

DELTA NA . GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains		Services		Meters		Customer Accounts		Customer Service Expense	
			Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer	Customer
<b>Internally Generated Functional Vectors</b>												
Sub-Total Distribution Plant		PTDSUB	0.373140		0.137031		0.178676					
Storage-Transmission-Distribution Subtotal		PTSUB	0.222266		0.081624		0.106431					
Total Storage Plant		PTST	-		-		-					
Transmission Plant		PT365	-		-		-					
General Plant		PT389	0.222266		0.081624		0.106431					
Total Distribution Plant		PTDSUB	0.373140		0.137031		0.178676					
Sub-Total CWIP		CWIP	0.078295		0.017792		0.023199					
Total Depreciation Reserve		DEPR	0.216329		0.079444		0.103568					
Storage-Transmission -Distribution Plant Subtotal		PTSUB	0.222266		0.081624		0.106431					
Transmission and Distribution Payroll		LBTD	0.243602		0.082913		0.114046					
Transmission and Distribution Mains		TDSUB	0.308767		-		-					
Storage Operation Expenses Subtotal		OSE	-		-		-					
Storage Maintenance Expenses Subtotal		MSE	-		-		-					
Mains & Services		CADAL	34,847.853		12,797.407		-					
Demand/Commodity Percent of Purchased Gas Cost		DMCM	-		-		-					
Distribution Operation Expenses Subtotal		DOES	52.663		1,344		18,065					
Distribution Maintenance Expenses Subtotal		DMES	669.659		227,927		313,510		404,578			
Subtotal Labor Expenses		LBSUB	1,086,818		367,895		539,011		1,113,070			
Subtotal O&M Expenses		OMSUB										2,264

DELTA NATIONAL GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<u>Plant in Service</u>										
Gas Supply Costs										
Demand	PTIS	PTISGSD	DEM01	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Commodity	PTIS	PTISGSC	COM01	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Procurement Expenses				\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Storage										
Demand	PTIS	PTISSD	DEM02	\$ 17,875,861	\$ 8,293,256	\$ 2,639,573	\$ 6,943,033	\$ -	\$ -	\$ -
Commodity	PTIS	PTISSC	COM02	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Storage				\$ 17,875,861	\$ 8,293,256	\$ 2,639,573	\$ 6,943,033	\$ -	\$ -	\$ -
Transmission										
Demand	PTIS	PTISTD	TDEM	\$ 57,549,027	\$ 16,048,581	\$ 5,092,582	\$ 12,544,907	\$ 2,581,547	\$ 5,290,335	\$ 15,991,076
Commodity	PTIS	PTISTC	COM03	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Transmission				\$ 57,549,027	\$ 16,048,581	\$ 5,092,582	\$ 12,544,907	\$ 2,581,547	\$ 5,290,335	\$ 15,991,076
Distribution Expenses										
Commodity	PTIS	PTISDEC	COM04	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Distribution Structures & Equipment										
Demand	PTIS	PTISDSD	DEM04	\$ 2,553,073	\$ 1,117,345	\$ 354,559	\$ 873,410	\$ 179,734	\$ 28,025	\$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<u>Plant in Service (Continued)</u>										
Distribution Mains										
Demand Customer	PTIS	PTISDMD	DEM05	\$ 30,091,574	\$ 13,169,488	\$ 4,178,980	\$ 10,294,368	\$ 2,118,421	\$ 330,319	\$ -
Total Distribution Mains	PTIS	PTISDMC	CUST01	\$ 39,148,127	\$ 33,505,637	\$ 4,694,354	\$ 907,953	\$ 39,163	\$ 1,031	\$ -
Services Customer	PTIS	PTISSC	CUST02	\$ 14,376,625	\$ 10,402,095	\$ 2,949,667	\$ 979,288	\$ 42,239	\$ 3,335	\$ -
Meters Customer	PTIS	PTISMC	CUST03	\$ 18,745,871	\$ 11,403,369	\$ 1,852,410	\$ 4,322,532	\$ 1,035,848	\$ 131,713	\$ -
Customer Accounts Customer	PTIS	PTISCAC	CUST04	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Customer Service Customer	PTIS	PTISCSC	CUST05	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total		PLT		\$ 180,340,159	\$ 93,939,761	\$ 21,762,124	\$ 36,865,489	\$ 5,996,952	\$ 5,784,757	\$ 15,991,076

DELTA NATURAL GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Rate Base</b>										
Gas Supply Costs										
Demand	NCRB	RBGSD	DEM01	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Commodity	NCRB	RBGSC	COM01	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Procurement Expenses				\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Storage										
Demand	NCRB	RBSD	DEM02	\$ 21,666,046	\$ 10,051,659	\$ 3,199,236	\$ 8,415,150	\$ -	\$ -	\$ -
Commodity	NCRB	RBSC	COM02	\$ 32,330	\$ 14,289	\$ 4,722	\$ 13,319	\$ -	\$ -	\$ -
Total Storage				\$ 21,698,376	\$ 10,065,949	\$ 3,203,959	\$ 8,428,469	\$ -	\$ -	\$ -
Transmission										
Demand	NCRB	RBTD	TDEM	\$ 34,615,060	\$ 9,633,032	\$ 3,063,128	\$ 7,545,613	\$ 1,552,770	\$ 3,182,074	\$ 9,618,444
Commodity	NCRB	RBTC	COM03	\$ 34,669	\$ 3,599	\$ 1,168	\$ 4,468	\$ 2,534	\$ 5,663	\$ 17,236
Total Transmission				\$ 34,649,729	\$ 9,636,631	\$ 3,064,296	\$ 7,550,082	\$ 1,555,304	\$ 3,187,737	\$ 9,635,680
Distribution Expenses										
Commodity	NCRB	RBDEC	COM04	\$ 8,836	\$ 2,606	\$ 846	\$ 3,235	\$ 1,835	\$ 314	\$ -
Distribution Structures & Equipment										
Demand	NCRB	RBDS	DEM04	\$ 1,515,862	\$ 663,412	\$ 210,516	\$ 518,578	\$ 106,715	\$ 16,640	\$ -



DELTA NATURAL GAS COMPANY

PSC SECOND DA. .-QUEST # 46

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Rate Base (Continued)</b>										
<b>Distribution Mains</b>										
Demand	NCRB	RBDMD	DEM05	\$ 17,901,507	\$ 7,834,341	\$ 2,486,079	\$ 6,124,129	\$ 1,260,251	\$ 196,507	\$ -
Customer	NCRB	RBDMC	CUST01	\$ 23,289,259	\$ 19,932,530	\$ 2,792,676	\$ 540,142	\$ 23,298	\$ 613	\$ -
Total Distribution Mains				\$ 41,190,766	\$ 27,767,071	\$ 5,278,755	\$ 6,664,271	\$ 1,283,548	\$ 197,120	\$ -
<b>Services</b>										
Customer	NCRB	RBSC	CUST02	\$ 8,520,666	\$ 6,165,062	\$ 1,748,194	\$ 580,399	\$ 25,034	\$ 1,976	\$ -
<b>Meters</b>										
Customer	NCRB	RBMC	CUST03	\$ 11,132,896	\$ 6,772,392	\$ 1,100,119	\$ 2,567,088	\$ 615,175	\$ 78,222	\$ -
<b>Customer Accounts</b>										
Customer	NCRB	RBCAC	CUST04	\$ 220,794	\$ 174,835	\$ 24,064	\$ 20,504	\$ 652	\$ 87	\$ 652
<b>Customer Service</b>										
Customer	NCRB	RBCSC	CUST05	\$ 344	\$ 294	\$ 41	\$ 9	\$ 0	\$ 0	\$ -
Total		RBT		\$ 118,938,270	\$ 61,268,154	\$ 14,630,788	\$ 26,332,635	\$ 3,588,264	\$ 3,482,097	\$ 9,656,332

DELTA NATURAL GAS COMPANY

PSC SECOND D: REQUEST #46

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Operation and Maintenance Expenses</b>										
<b>Gas Supply Costs</b>										
Demand	OMT	OMGSD	DEM01	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Commodity	OMT	OMGSC	COM01	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Procurement Expenses		OMGST		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<b>Storage</b>										
Demand	OMT	OMSD	DEM02	\$ 376,007	\$ 174,443	\$ 55,522	\$ 146,042	\$ -	\$ -	\$ -
Commodity	OMT	OMSC	COM02	\$ 257,240	\$ 113,694	\$ 37,573	\$ 105,973	\$ -	\$ -	\$ -
Total Storage		OMST		\$ 633,246	\$ 288,137	\$ 93,095	\$ 252,015	\$ -	\$ -	\$ -
<b>Transmission</b>										
Demand	OMT	OMTD	TDEM	\$ 2,802,949	\$ 781,653	\$ 248,036	\$ 611,005	\$ 125,735	\$ 257,668	\$ 778,852
Commodity	OMT	OMTC	COM03	\$ 275,846	\$ 28,639	\$ 9,294	\$ 35,553	\$ 20,162	\$ 45,060	\$ 137,139
Total Transmission		OMTRT		\$ 3,078,795	\$ 810,292	\$ 257,330	\$ 646,557	\$ 145,897	\$ 302,728	\$ 915,991
<b>Distribution Expenses</b>										
Commodity	OMT	OMDEC	COM04	\$ 70,306	\$ 20,737	\$ 6,730	\$ 25,742	\$ 14,598	\$ 2,499	\$ -
<b>Distribution Structures &amp; Equipment</b>										
Demand	OMT	OMDSD	DEM04	\$ 145,166	\$ 63,532	\$ 20,160	\$ 49,662	\$ 10,220	\$ 1,594	\$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Operation and Maintenance Expenses (Continued)</b>										
Distribution Mains										
Demand Customer	OMT	OMDMD	DEM05	\$ 1,721,636	\$ 753,469	\$ 239,093	\$ 588,974	\$ 121,202	\$ 18,899	\$ -
Total Distribution Mains	OMT	OMDMC	CUST01	\$ 2,239,790	\$ 1,916,965	\$ 268,579	\$ 51,947	\$ 2,241	\$ 59	\$ -
Services Customer	OMT	OMSC	CUST02	\$ 766,364	\$ 554,497	\$ 157,236	\$ 52,202	\$ 2,252	\$ 178	\$ -
Meters Customer	OMT	OMMC	CUST03	\$ 1,087,545	\$ 661,568	\$ 107,468	\$ 250,772	\$ 60,095	\$ 7,641	\$ -
Customer Accounts Customer	OMT	OMCAC	CUST04	\$ 1,756,764	\$ 1,391,087	\$ 191,467	\$ 163,138	\$ 5,190	\$ 692	\$ 5,190
Customer Service Customer	OMT	OMCSC	CUST05	\$ 2,737	\$ 2,343	\$ 322	\$ 69	\$ 2	\$ 0	\$ -
Total		OMTT		\$ 11,502,349	\$ 6,462,625	\$ 1,341,480	\$ 2,081,078	\$ 361,696	\$ 334,289	\$ 921,181



Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Payroll Expenses</b>										
<b>Distribution Mains</b>										
Demand Customer	LBTOT	LBDMD	DEM05	1,072,603 \$	469,421 \$	148,958 \$	366,939 \$	75,510 \$	11,774 \$	-
Total Distribution Mains	LBTOT	LBDMC	CUST01	1,395,420 \$	1,194,295 \$	167,328 \$	32,364 \$	1,396 \$	37 \$	-
				2,468,023 \$	1,663,717 \$	316,287 \$	399,302 \$	76,906 \$	11,811 \$	-
<b>Services</b>										
Customer	LBTOT	LBSC	CUST02	474,949 \$	343,646 \$	97,446 \$	32,352 \$	1,395 \$	110 \$	-
<b>Meters</b>										
Customer	LBTOT	LBMC	CUST03	653,285 \$	397,402 \$	64,556 \$	150,638 \$	36,099 \$	4,590 \$	-
<b>Customer Accounts</b>										
Customer	LBTOT	LBCAC	CUST04	843,051 \$	667,566 \$	91,883 \$	78,288 \$	2,491 \$	332 \$	2,491
<b>Customer Service</b>										
Customer	LBTOT	LBCSC	CUST05	- \$	- \$	- \$	- \$	- \$	- \$	-
Total		LBTT		6,765,762 \$	3,741,478 \$	783,054 \$	1,198,775 \$	219,135 \$	217,268 \$	606,051

DELTA NATURAL GAS COMPANY

PSC SECOND DRAFT REQUEST # 46

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Depreciation Expenses</b>										
<b>Gas Supply Costs</b>										
Demand	DEPREX	DEGSD	DEM01	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Commodity	DEPREX	DEGSC	COM01	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Procurement Expenses		DEGST		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<b>Storage</b>										
Demand	DEPREX	DESD	DEM02	\$ 272,969	\$ 126,640	\$ 40,307	\$ 106,022	\$ -	\$ -	\$ -
Commodity	DEPREX	DESC	COM02	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Storage		DEST		\$ 272,969	\$ 126,640	\$ 40,307	\$ 106,022	\$ -	\$ -	\$ -
<b>Transmission</b>										
Demand	DEPREX	DETD	TDEM	\$ 1,292,154	\$ 360,340	\$ 114,344	\$ 281,672	\$ 57,964	\$ 118,784	\$ 359,049
Commodity	DEPREX	DETC	COM03	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Transmission		DETT		\$ 1,292,154	\$ 360,340	\$ 114,344	\$ 281,672	\$ 57,964	\$ 118,784	\$ 359,049
<b>Distribution Expenses</b>										
Commodity	DEPREX	DEDEC	COM04	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<b>Distribution Structures &amp; Equipment</b>										
Demand	DEPREX	DESDS	DEM04	\$ 65,118	\$ 28,499	\$ 9,043	\$ 22,277	\$ 4,584	\$ 715	\$ -

DELTA NATURAL GAS COMPANY  
 Cost of Service Study  
 12 Months Ended December 31, 2006  
 Class Allocation

PSC SECOND D. REQUEST # 46

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<u>Depreciation Expenses (Continued)</u>										
Distribution Mains										
Demand Customer	DEPREX DEDMD	DEM05	\$	747,809 \$	327,277 \$	103,852 \$	255,827 \$	52,645 \$	8,209 \$	-
Total Distribution Mains	DEPREX DEDMC	CUST01		972,875 \$	832,652 \$	116,660 \$	22,564 \$	973 \$	26 \$	-
				1,720,684 \$	1,159,929 \$	220,512 \$	278,390 \$	53,618 \$	8,234 \$	-
Services Customer	DEPREX DESC	CUST02	\$	351,207 \$	254,113 \$	72,058 \$	23,923 \$	1,032 \$	81 \$	-
Meters Customer	DEPREX DEMC	CUST03	\$	532,606 \$	323,991 \$	52,630 \$	122,811 \$	29,430 \$	3,742 \$	-
Customer Accounts Customer	DEPREX DECAC	CUST04	\$	- \$	- \$	- \$	- \$	- \$	- \$	-
Customer Service Customer	DEPREX DECSC	CUST05	\$	- \$	- \$	- \$	- \$	- \$	- \$	-
Total	DET		\$	4,234,739 \$	2,253,513 \$	508,895 \$	835,096 \$	146,629 \$	131,557 \$	359,049

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Other Taxes</b>										
Gas Supply Costs										
Demand	OTT	OTTGSD	DEM01	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Commodity	OTT	OTTGSC	COM01	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Procurement Expenses		OTTGST		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Storage										
Demand	OTT	OTTSD	DEM02	\$ 130,765	\$ 60,667	\$ 19,309	\$ 50,790	\$ -	\$ -	\$ -
Commodity	OTT	OTTSC	COM02	\$ 5,104	\$ 2,236	\$ 746	\$ 2,103	\$ -	\$ -	\$ -
Total Storage		OTTST		\$ 135,870	\$ 62,923	\$ 20,055	\$ 52,892	\$ -	\$ -	\$ -
Transmission										
Demand	OTT	OTTDD	TDEM	\$ 349,874	\$ 153,342	\$ 48,659	\$ 119,865	\$ 24,666	\$ 50,549	\$ 152,793
Commodity	OTT	OTTTC	COM03	\$ 12,606	\$ 1,309	\$ 425	\$ 1,625	\$ 921	\$ 2,059	\$ 6,267
Total Transmission		OTTTT		\$ 362,480	\$ 154,651	\$ 49,084	\$ 121,490	\$ 25,588	\$ 52,608	\$ 159,060
Distribution Expenses										
Commodity	OTT	OTTDEC	COM04	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Distribution Structures & Equipment										
Demand	OTT	OTTDSD	DEM04	\$ 23,940	\$ 10,477	\$ 3,325	\$ 8,190	\$ 1,685	\$ 263	\$ -



Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<u>Other Taxes (Continued)</u>										
Distribution Mains										
Demand	OTT	OTTDMD	\$	288,788 \$	126,387 \$	40,106 \$	98,795 \$	20,330 \$	3,170 \$	-
Customer	OTT	OTTDMC		375,703 \$	321,532 \$	45,052 \$	8,714 \$	376 \$	10 \$	-
Total Distribution Mains				664,491 \$	447,940 \$	85,157 \$	107,508 \$	20,706 \$	3,180 \$	-
Services Customer	OTT	OTTSC	\$	134,806 \$	97,538 \$	27,658 \$	9,183 \$	396 \$	31 \$	-
Meters Customer	OTT	OTTMC	\$	178,494 \$	108,580 \$	17,638 \$	41,158 \$	9,863 \$	1,254 \$	-
Customer Accounts Customer	OTT	OTTAC	\$	67,400 \$	53,371 \$	7,346 \$	6,239 \$	199 \$	27 \$	199
Customer Service Customer	OTT	OTTCSC	\$	- \$	- \$	- \$	- \$	- \$	- \$	-
Total		OTTT	\$	1,767,481 \$	935,479 \$	210,262 \$	346,680 \$	58,438 \$	57,362 \$	159,259

DELTA NATURAL GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<u>Interest Expense</u>										
Gas Supply Costs										
Demand	INT	INTGSD	DEM01	- \$	- \$	- \$	- \$	- \$	- \$	- \$
Commodity	INT	INTGSC	COM01	- \$	- \$	- \$	- \$	- \$	- \$	- \$
Total Procurement Expenses		INTGST		- \$	- \$	- \$	- \$	- \$	- \$	- \$
Storage										
Demand	INT	INTSD	DEM02	487,325 \$	226,088 \$	71,959 \$	189,278 \$	- \$	- \$	- \$
Commodity	INT	INTSC	COM02	- \$	- \$	- \$	- \$	- \$	- \$	- \$
Total Storage		INTST		487,325 \$	226,088 \$	71,959 \$	189,278 \$	- \$	- \$	- \$
Transmission										
Demand	INT	INTTD	TDEM	1,615,059 \$	450,388 \$	142,919 \$	352,061 \$	72,449 \$	148,468 \$	448,775 \$
Commodity	INT	INTTC	COM03	- \$	- \$	- \$	- \$	- \$	- \$	- \$
Total Transmission		INTTT		1,615,059 \$	450,388 \$	142,919 \$	352,061 \$	72,449 \$	148,468 \$	448,775 \$
Distribution Expenses										
Commodity	INT	INTDEC	COM04	- \$	- \$	- \$	- \$	- \$	- \$	- \$
Distribution Structures & Equipment										
Demand	INT	INTDSD	DEM04	69,647 \$	30,481 \$	9,672 \$	23,826 \$	4,903 \$	765 \$	- \$

DELTA NATURAL GAS COMPANY

PSC SECOND DA. .EQUEST # 46

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Interest Expense (Continued)</b>										
Distribution Mains										
Demand Customer	INT	INTDMD	DEMO5	822,308 \$	359,881 \$	114,198 \$	281,313 \$	57,890 \$	9,027 \$	-
Customer	INT	INTDMC	CUST01	1,069,795 \$	915,604 \$	128,282 \$	24,812 \$	1,070 \$	28 \$	-
Total Distribution Mains				1,892,104 \$	1,275,484 \$	242,480 \$	306,124 \$	58,960 \$	9,055 \$	-
Services Customer	INT	INTSC	CUST02	392,190 \$	283,766 \$	80,466 \$	26,715 \$	1,152 \$	91 \$	-
Meters Customer	INT	INTMC	CUST03	511,381 \$	311,080 \$	50,533 \$	117,917 \$	28,258 \$	3,593 \$	-
Customer Accounts Customer	INT	INTCAC	CUST04	- \$	- \$	- \$	- \$	- \$	- \$	-
Customer Service Customer	INT	INTCSC	CUST05	- \$	- \$	- \$	- \$	- \$	- \$	-
Total		INTT		4,967,706 \$	2,577,287 \$	598,029 \$	1,015,922 \$	165,722 \$	161,972 \$	448,775

DELTA NATURAL GAS COMPANY

PSC SECOND Docket REQUEST # 46

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<u>Net Operating Income -- Adjusted Test Period</u>										
Operating Revenues										
Sales and Transportation		REVUC		25,395,331	11,599,893	3,391,784	5,685,582	1,625,063	608,063	2,484,947
Collection Fees		COLFEE	\$	137,310	124,139	12,285	886	-	-	-
Reconnect Revenue		RCTREV		113,896	97,954	15,030	864	48	-	-
Bad Check Revenue		BDCH		10,095	9,035	970	90	-	-	-
Total Operating Revenues -- Per Books		TOR	\$	25,656,632	11,831,021	3,420,069	5,687,422	1,625,110	608,063	2,484,947
Pro-Forma Adjustments to Revenues										
Temperature normalization		REVADJ1	\$	106,453	(53,005)	(6,064)	163,640	1,882	-	-
Total Revenue Adjustments			\$	106,453	(53,005)	(6,064)	163,640	1,882	-	-
Total Adjusted Revenue			\$	25,763,085	11,778,016	3,414,004	5,851,062	1,626,992	608,063	2,484,947
Expenses										
Operation and Maintenance Expenses			\$	11,502,349	6,462,625	1,341,480	2,081,078	361,696	334,289	921,181
Depreciation and Amortization Expenses			\$	4,234,739	2,253,513	508,895	835,096	146,629	131,557	359,049
Other Taxes			\$	1,767,481	935,479	210,262	346,680	58,438	57,362	159,259
Total Operating Expenses		TOE	\$	17,504,569	9,651,617	2,060,637	3,262,854	566,762	523,209	1,439,489

DELTA NATURAL GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Net Operating Income -- Adjusted Test Period (Cont.)</b>										
Pro-Forma Adjustments to Expenses										
Labor Adjustment		EXADJ1	\$	52,914 \$	29,262 \$	6,124 \$	9,375 \$	1,714 \$	1,699 \$	4,740
Eliminate Advertising Expenses		EXADJ2		(2,264) \$	(1,034) \$	(302) \$	(507) \$	(145) \$	(54) \$	(222)
Lobbying Expense		EXADJ3		(26,488) \$	(12,099) \$	(3,538) \$	(5,930) \$	(1,695) \$	(634) \$	(2,592)
Community Relations		EXADJ4		(22,664) \$	(10,352) \$	(3,027) \$	(5,074) \$	(1,450) \$	(543) \$	(2,218)
Marketing		EXADJ5		(3,973) \$	(2,232) \$	(463) \$	(719) \$	(125) \$	(115) \$	(318)
Rate Case Expenses		EXADJ6		33,700 \$	18,934 \$	3,930 \$	6,097 \$	1,060 \$	979 \$	2,699
Depreciation Expenses		EXADJ7		292,968 \$	155,903 \$	35,206 \$	57,774 \$	10,144 \$	9,101 \$	24,840
Payroll Tax		EXADJ8		3,910 \$	2,162 \$	453 \$	693 \$	127 \$	126 \$	350
Total Expense Adjustments		ADJTOT	\$	328,103 \$	180,543 \$	38,383 \$	61,709 \$	9,629 \$	10,559 \$	27,279
Net Income Before Income Taxes			\$	7,930,413 \$	1,945,856 \$	1,314,984 \$	2,526,499 \$	1,050,601 \$	74,295 \$	1,018,178
Income Taxes		TXINC	\$	1,138,000 \$	(315,241) \$	286,093 \$	608,851 \$	364,834 \$	(38,332) \$	231,797
Net Operating Income (Adjusted)		TOM	\$	6,792,413 \$	2,261,097 \$	1,028,892 \$	1,917,649 \$	685,767 \$	112,627 \$	786,382
Net Cost Rate Base			\$	118,938,270 \$	61,268,154 \$	14,630,788 \$	26,332,635 \$	3,588,264 \$	3,482,097 \$	9,636,332
Rate of Return -- Actual				5.71%	3.69%	7.03%	7.28%	19.11%	3.23%	8.16%

DELTA NATURAL GAS COMPANY

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Net Operating Income -- Adjusted For Increase</b>										
Test Year Operating Income				\$ 6,792,413	\$ 2,261,097	\$ 1,028,892	\$ 1,917,649	\$ 685,767	\$ 112,627	\$ 786,382
Proposed Increase				\$ 5,563,328	\$ 3,847,603	\$ 489,441	\$ 1,130,709	\$ -	\$ -	\$ 95,575
Increase To Misc Revenue		RCNCT		\$ 79,309	\$ 70,401	\$ 8,340	\$ 56	\$ 12	\$ -	\$ -
Total Increase		CLSINC		\$ 5,642,637	\$ 3,918,004	\$ 497,781	\$ 1,131,265	\$ 12	\$ -	\$ 95,575
<b>Incremental Income Taxes (@39.4445)</b>										
		CLSINC		\$ 1,941,555	\$ 1,348,132	\$ 171,280	\$ 389,253	\$ 4	\$ -	\$ 32,886
<b>Net Operating Income Adjusted for Increase</b>										
				\$ 10,493,495	\$ 4,830,969	\$ 1,355,393	\$ 2,659,661	\$ 685,775	\$ 112,627	\$ 849,071
Net Cost Rate Base				\$ 118,938,270	\$ 61,268,154	\$ 14,630,788	\$ 26,332,635	\$ 3,588,264	\$ 3,482,097	\$ 9,636,332
<b>Rate of Return -- Proposed</b>				8.82%	7.88%	9.26%	10.10%	19.11%	3.23%	8.81%

DELTA NATURAL GAS COMPANY

PSC SECOND L. REQUEST # 46

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Allocation Factors</b>										
Commodity		COM01		17,149,249	1,780,480	577,814	2,210,287	1,253,445	2,801,367	8,525,855
Procurement Expenses		COM02		2,671,021	0,103,823	0,033,693	0,128,885	-	-	-
Storage (Dec thru March)		COM03		17,149,249	1,780,480	577,814	2,210,287	1,253,445	2,801,367	8,525,855
Transmission		COM04		6,036,593	1,780,480	577,814	2,210,287	1,253,445	214,567	-
Distribution				-	-	-	-	-	-	-
Demand		DEM01		84,012	23,443	7,439	18,325	3,771	7,675	23,359
Procurement Expenses		DEM02		1,00000	0,463,936	0,147,661	0,368,403	-	-	-
Storage				-	0,463,936	0,147,661	0,368,403	-	-	-
Transmission		DEM03		84,012	23,443	7,439	18,325	3,771	7,675	23,359
Distribution Structures		DEM04		53,566	23,443	7,439	18,325	3,771	588	-
Distribution Mains		DEM05		53,566	23,443	7,439	18,325	3,771	588	-
Customer		CUST01		37,986	32,511	4,555	881	38	1	-
Distribution Mains (Year-end Customers)		CUST02		13,391,413	9,689,253	2,747,530	912,179	39,345	3,106	-
Services		CUST03		5,849,497	3,558,329	578,030	1,348,811	323,228	41,100	-
Meters				37,568	32,164	4,427	943	30	4	-
Customer Count (Average)		CUST04		40,619	32,164	4,427	3,772	120	16	120
Customer Accounts		CUST05		37,568	32,164	4,427	943	30	4	-
Customer Service				-	-	-	-	-	-	-
Forfeited Discounts		REVFD		2,641,717	2,168,773	432,108	9,080	2,703	18,740	9,961

DELTA NATURAL GAS COMPANY

PSC SECOND D.A. REQUEST # 46

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Allocation Factors Continued</b>										
<b>Taxable Income Actual</b>										
Net Income Before Income Tax		NIBIT	\$	7,930,413	1,945,856	1,314,984	2,525,499	1,050,601	74,295	1,018,178
Interest Expense		INT	\$	4,967,706	2,587,694	599,466	1,015,508	165,194	159,349	440,495
Interest Adjustment		PLT	\$	224,173	116,772	27,052	45,826	7,455	7,191	19,878
Taxable Income		TXINC	\$	2,738,534	(758,611)	688,467	1,465,165	877,952	(92,245)	557,805
<b>Meter Allocation</b>										
Number of Customers				37,988	32,511	4,555	881	38	3	-
Average Cost Per Service Meter Cost				5,849,497	109,45	126.9	1531	8506	13700	-
					3,558,329	578,030	1,348,811	323,228	41,100	-
<b>Service Line Allocation</b>										
Number of Customers				37,988	32,511	4,555	881	38	3	-
Average Cost Per Service Service Cost				13,391,413	288.03	603.19	1035.39	1035.39	1035.39	0
					9,689,253	2,747,530	912,179	39,345	3,106	-
Collection Fees		COLL		1,00000	0.90408	0.08947	0.00645			
Reconnect Revenue		RCNCT		1,00000	0.86003	0.13196	0.00759	0.00042		
Bad Check Fees		BDCK		1,00000	0.89500	0.09608	0.00892			
Customer Deposits		CSTDEP		1,00000	0.89690	0.08960	0.00980	0.00370		
<b>Transmission Allocator</b>										
Transmission Demand Allocator			\$	84,012	23,443	7,439	18,325	3,771	7,675	23,359
Specific Assignment			\$	57,549,027						
Residual Transmission Plant		DEM03	\$	36,192.40					36,192.40	
Total Allocation of Transmission Plant			\$	57,512,834	16,048,581	5,092,582	12,544,907	2,381,547	5,254,142	15,991,076
Transmission Allocator		TDEM	\$	57,549,027	16,048,580.89	5,092,581.72	12,544,906.58	2,581,546.67	5,290,334.72	15,991,076.27
				1,000000	0.27868798	0.088491187	0.217986424	0.044868216	0.09192744	0.277868752



DELTA NATURAL GAS COMPANY

PSC SECOND CLASS REQUEST # 46

Cost of Service Study  
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<b>Customer Related Unit Cost</b>										
Rate Base			\$	43,163,959	33,045,014	5,665,093	3,708,141	664,160	80,899	652
Rate of Return				8.82%	8.82%	8.82%	8.82%	8.82%	8.82%	8.82%
Return			\$	3,808,201	2,915,443	499,811	327,156	58,596	7,137	56
Income Taxes			\$	413,143	(170,043)	110,791	85,763	67,610	(892)	16
Operation and Maintenance Expenses				5,853,199	4,526,459	725,072	518,128	69,779	8,570	5,190
Depreciation Expenses				1,856,688	1,410,757	241,348	169,298	31,436	3,849	-
Other Taxes				756,403	581,041	97,694	65,313	10,834	1,322	199
Expense Adjustment (Classified Pro-Rata on the basis of Operating Expenses)				158,805	121,947	19,825	14,243	1,907	278	103
Total Customer-Related Revenue Requirement			\$	12,846,440	9,385,605	1,694,541	1,179,902	240,162	20,265	5,565
Less: Misc Service Revenues				(49,687)	(61,617)	(6,930)	(163)	(9)	-	-
Net Revenue Requirement			\$	12,796,754	9,323,988	1,687,612	1,179,739	240,153	20,265	5,565
Customer-Months				37,568	32,164	4,427	943	30	4	-
Customer-Related Unit Cost (\$/Cust/Mo)				28,386	24,157	31,767	104,254	667,092	422,193	-



**DELTA NATURAL GAS COMPANY, INC.**  
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47. Refer to the Seelye Testimony, page 29. Delta states that it prefers not to make a year-end customer adjustment due to the numerous customers who voluntarily disconnect during the non-winter months.
- a. Provide the basis for the customer count used in Seelye Exhibit 4, page 1 of 16, and explain why this method is appropriate.
  - b. Provide the number of customers by month and by customer class for the period 2002 through 2006.
  - c. Explain how increasing rates will prevent customers from leaving in the next few years.

RESPONSE:

- A. The customer count of 385,374 represents the number of customers billed in the calendar year ended December 31, 2006. During the period from 2002 to 2006, Delta Natural Gas has experienced a steady decrease in the number of residential customers served. Considering the current downward trend in the number of residential customers served, the 385,374 residential customer-months during the test year may in fact overstate the actual customer-months that will be billed during the 12-month period when the new rates go into effect. Because Delta is not proposing to use a forecasted test-year in this proceeding, we did not make a downward adjustment to customer billing units based on this trend, even though such an adjustment could be justified.
- B. Please see attached.
- C. Increasing rates will not prevent customers from leaving the system in the next few years. Delta is proposing to increase its rates so that it will have an opportunity to earn a fair and reasonable rate of return. However, Delta anticipates that its proposed rate design, which recovers most of increase through the customer charge rather than through the volumetric charge, will encourage customers to continue to take natural gas service, especially customers with space heating requirements. Ultimately, customer decisions to continue to take gas service will depend on a number of factors, including trends in gas supply costs, the age of appliance stocks, new construction trends, customer preferences for heating and cooking, as well as the level of incremental distribution charges.

Sponsoring Witness:

William Steven Seelye

YY/M	Residential	Small Non Residential	Large Non Residential	Interruptible	Total
Average 2002	33,721	4,452	874	8	39,055
Average 2003	33,700	4,476	868	9	39,052
Average 2004	33,391	4,470	864	9	38,734
Average 2005	33,082	4,417	845	8	38,351
Average 2006	32,148	4,320	859	8	37,334

YY/M	Residential	Small Non Residential	Large Non Residential	Interruptible	Total
2002 01	34,578	4,639	882	8	40,107
2002 02	34,766	4,689	878	8	40,341
2002 03	34,749	4,703	886	7	40,345
2002 04	34,599	4,677	884	7	40,167
2002 05	34,089	4,529	880	7	39,505
2002 06	33,287	4,338	872	8	38,505
2002 07	32,818	4,222	869	8	37,917
2002 08	32,624	4,183	864	8	37,679
2002 09	32,534	4,161	863	8	37,566
2002 10	32,576	4,160	863	9	37,608
2002 11	33,555	4,450	878	9	38,892
2002 12	34,479	4,667	872	9	40,027
<b>Total</b>	<b>404,654</b>	<b>53,418</b>	<b>10,491</b>	<b>96</b>	<b>468,659</b>
<b>Average</b>	<b>33,721</b>	<b>4,452</b>	<b>874</b>	<b>8</b>	<b>39,055</b>

YY/M	Residential	Small Non Residential	Large Non Residential	Interruptible	Total
2003 01	34,711	4,720	876	9	40,316
2003 02	34,922	4,748	873	9	40,552
2003 03	34,934	4,741	880	9	40,564
2003 04	34,692	4,692	875	9	40,268
2003 05	34,042	4,568	874	9	39,493
2003 06	33,193	4,357	869	8	38,427
2003 07	32,816	4,257	863	8	37,944
2003 08	32,521	4,204	856	8	37,589
2003 09	32,429	4,179	857	8	37,473
2003 10	32,570	4,207	850	8	37,635
2003 11	33,464	4,414	866	9	38,753
2003 12	34,100	4,629	872	9	39,610
<b>Total</b>	<b>404,394</b>	<b>53,716</b>	<b>10,411</b>	<b>103</b>	<b>468,624</b>
<b>Average</b>	<b>33,700</b>	<b>4,476</b>	<b>868</b>	<b>9</b>	<b>39,052</b>

YY/M	Residential	Small Non Residential	Large Non Residential	Interruptible	Total
2004 01	34,525	4,724	885	9	40,143
2004 02	34,678	4,747	884	9	40,318
2004 03	34,696	4,755	888	9	40,348
2004 04	34,325	4,705	875	9	39,914
2004 05	33,742	4,584	870	9	39,205
2004 06	32,970	4,370	869	9	38,218
2004 07	32,387	4,262	866	8	37,523
2004 08	32,256	4,241	861	8	37,366
2004 09	32,237	4,227	861	8	37,333
2004 10	32,250	4,167	830	9	37,256
2004 11	32,934	4,316	841	9	38,100
2004 12	33,691	4,545	843	9	39,088
<b>Total</b>	<b>400,691</b>	<b>53,643</b>	<b>10,373</b>	<b>105</b>	<b>464,812</b>
<b>Average</b>	<b>33,391</b>	<b>4,470</b>	<b>864</b>	<b>9</b>	<b>38,734</b>

YY/M	Residential	Small Non Residential	Large Non Residential	Interruptible	Total
2005 01	34,189	4,680	848	9	39,726
2005 02	34,410	4,696	851	9	39,966
2005 03	34,454	4,672	854	8	39,988
2005 04	34,218	4,642	852	8	39,720
2005 05	33,498	4,496	848	8	38,850
2005 06	32,882	4,362	841	8	38,093
2005 07	32,284	4,227	830	7	37,348
2005 08	31,950	4,176	834	7	36,967
2005 09	31,699	4,136	835	7	36,677
2005 10	31,776	4,136	837	7	36,756
2005 11	32,296	4,267	849	8	37,420
2005 12	33,323	4,513	858	8	38,702
<b>Total</b>	<b>396,979</b>	<b>53,003</b>	<b>10,137</b>	<b>94</b>	<b>460,213</b>
<b>Average</b>	<b>33,082</b>	<b>4,417</b>	<b>845</b>	<b>8</b>	<b>38,351</b>

YY/M	Residential	Small Non Residential	Large Non Residential	Interruptible	Total
2006 01	33,571	4,565	861	8	39,005
2006 02	33,596	4,556	863	8	39,023
2006 03	33,558	4,555	862	8	38,983
2006 04	33,227	4,523	866	8	38,624
2006 05	32,274	4,374	861	7	37,516
2006 06	31,662	4,217	859	7	36,745
2006 07	31,131	4,125	855	7	36,118
2006 08	30,827	4,088	845	7	35,767
2006 09	30,832	4,061	851	7	35,751
2006 10	30,885	4,066	850	7	35,808
2006 11	31,697	4,265	863	8	36,833
2006 12	32,511	4,449	868	8	37,836
<b>Total</b>	<b>385,771</b>	<b>51,844</b>	<b>10,304</b>	<b>90</b>	<b>448,009</b>
<b>Average</b>	<b>32,148</b>	<b>4,320</b>	<b>859</b>	<b>8</b>	<b>37,334</b>



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48. Refer to the Seelye Testimony, page 30. Provide the survivor curves and depreciation rates from neighboring gas utilities that were utilized in Delta's depreciation study, as references at lines 11 through 13.

RESPONSE:

See attached.

Sponsoring Witness:

William Steven Seelye

## Survivor Curves from Other Regional LDCs' Depreciation Studies

	LG&E		Vectren South		CG&E	
	ASL	Curve Type	ASL	Curve Type	ASL	Curve Type
305						
325						
327						
331						
332						
333			40	AQ		
334			32	SQ		
351	35	R 2				
352	38	R 3	44	R 4		
3521						
3522	45	R 3				
3523	45	R 3				
353	28	L 4	44	R 3		
354	40	S 4	37	R 5		
355	33	R 4	32	R 3		
356	30	R 3	28	S 6		
357	30	R 3				
3652			46	R 4		
3653						
366			43	R 4		
367	45	R 4	46	R 4		
368			30	SQ		
369			22	S 2		
371			25	SQ	14	L .5
375	35	L .5	48	R 3	47	S .5
376	55	S 3	38	R 2.5	50	R .3
378	36	S 1.5	34	S .5	33	R .5
379	33	R 3	39	R 1.5	10	L .5
380	42	R 2	39	R 1.5	40	R 1
381	35	R 5	26	R 2	43	R 2
382	35	R 5	32	R 2		
383	45	R 4	35	R 2		
385	30	S 0				
390	45	SQ	37	S 4		
391			21	S 0		
392	20	L 0	7	S 2		
393			30	SQ		
394	35	R 4	20	R 5		
39401						
395	30	S 1.5	18	R 4		
396	30	L 3.0	13	S 6		
397	25	S 0	22	R 5		
398	20	R 2	21	R 4		
399.1						
399.2						
399031						
399033						





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49. Refer to the Seelye Testimony, Seelye Exhibit 4, page 16 of 16. Should the Collection Fees, Reconnect Revenue and Bad Check Revenue charges under "Proposed" be \$20, \$60, and \$15 respectively?

RESPONSE:

Yes. See the attached corrected page.

Sponsoring Witness:

William Steven Seelye

**Delta Natural Gas Company, Inc.**

Calculated Increase in Revenue under Proposed Revision of Rates  
 Based on the adjusted sales for the 12 months Ended December 31, 2006

Miscellaneous Charges	Current		Proposed		Difference	
	Units	Charge	Revenue	Charge		Revenue
Collection Fees	9,154	\$ 15.00	\$ 137,310	\$ 20.00	\$ 183,080	\$ 45,770
Reconnect Revenue	2,373	48.00	113,896.00	60.00	142,380	28,484
Bad Check Revenue	1,010	10.00	10,095.00	15.00	15,150	5,055
<b>Total</b>			<u>\$ 261,301</u>		<u>\$ 340,610</u>	<u>\$ 79,309</u>



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50. Refer to the Seelye Testimony, Seelye Exhibit 11.
- a. Provide the survival curves for all accounts that best fit the data provided by Delta and recommended by the depreciation study.
  - b. Refer to pages 2 through 10. Several of the plant account narratives end with the statement, "The recommended accrual rate is reasonable compared with other gas distribution utilities in the region." For each plant account narrative containing this statement, identify the applicable gas distribution utilities.
  - c. Refer to page 4. Explain the reason(s) for the recommended depreciation rate for Account No. 305 – Structures and Improvements – Manufactured Gas Plant.
  - d. Refer to page 5. The narrative for Account No. 334 – Gathering Lines states that Delta is currently using a depreciation accrual rate of 4.00 percent, but the study is recommending Delta maintain its current accrual rate of 2.72 percent. Indicate the correct current depreciation rate and clarify the depreciation study recommendation for this account.
  - e. Previous depreciation studies submitted to the Commission for approval included an analysis of the book salvage data. This "Summary of Book Salvage" examined the regular retirements, the cost of removal (amount and percentage), the gross salvage (amount and percentage), and the net salvage (amount and percentage) for the entire historical experience for each plant account, as well as calculated 3-year and 5-year moving averages. Did Mr. Seelye prepare such an analysis by plant account number in conjunction with the depreciation study?
    - (1) If yes, provide copies of the analysis.
    - (2) If no, explain why this particular analysis was not prepared.
  - f. Provide all workpapers, calculations, and assumptions that support Appendices A through C of Seelye Exhibit 11.

**RESPONSE:**

- a. Although other statistics were utilized in selecting the appropriate survivor curve, including the conformance index and index of variation, the following lists the survival curves that best fit the data in terms of the sum of squared deviations ("SSD") for those accounts with sufficient data to conduct a statistical analysis:

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Acct	Description	ASL	Curve Type
366	Structures & Improvements - Transmission	49	R 5
367	Mains -- Transmission	43	R 3
368	Compressor Station Equipment -- Transmission	36	S 4
369	Meas and Regulator Station Equip -- Transmission	39	S 3
375	Structures and Improvements -- Distribution	34	L 3
376	Mains -- Distribution	34	R 4
378	Meas and Regulator Station Equipment -- Distribution	36	R 1
379	Meas and Reg Station Equipment -- City Gate	37	R 2
381	Meters	40	S 1
382	Meter & Regulator Installations	40	S 1
383	Houes Regulators	28	S 6
385	Ind Meas and Reg Station Equipment -- Distribution	43	R 1
390	Structures and Improvements -- General Plant	32	R 3

b. Listed below are the gas utilities referenced:

Acct	Description	Utilities
367	Mains -- Transmission	LG&E/Vectren
375	Structures and Improvements -- Distribution	LG&E
376	Mains -- Distribution	Vectren
378	Meas and Regulator Station Equipment -- Distribution	LG&E/Vectren/CG&E
379	Meas and Reg Station Equipment -- City Gate	LG&E/Vectren
380	Services -- Distribution	Vectren
381	Meters	LG&E
382	Meter & Regulator Installations	LG&E/Vectren
383	Houes Regulators	Vectren

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- c. Because there is currently no plant recorded in this account, the depreciation rate, if ever used, would initially apply to new plant. The 4.0% rate assumes a life for new plant of 25 years. This depreciation rate will be re-evaluated in future depreciation studies.
- d. The current rate for Account 334 is 2.72 percent. The rate proposed by Delta is 2.72 percent, as shown in Appendix A of the report, and not 4.00 as indicated on page 5 of the report.
- e. In the depreciation study in this proceeding we relied on the estimated salvage percentages from Delta's last depreciation study conducted approximately 3 years ago. In the last depreciation study, the salvage percentages were determined based on an analysis of actual salvage and removal costs; however, the amount of actual data was somewhat limited. For continuity, we determined that it was appropriate to maintain the same percentages which were developed in the last study. It is unlikely that the salvage and removal percentages would have changed significantly in this short of period. Furthermore, based on discussions with Delta personnel, nothing was identified to suggest that these percentages would have changed in the intervening period.
- f. The Excel spreadsheet with the input data and the depreciation model in VBA is included in the accompanying CD.

Sponsoring Witness:

William Steven Seelye

Delta Natural Gas Company  
 Depreciation Study  
 As of June 30, 2002  
 375 -- Distribution Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	34	L3	-	-	#NAME?	-	#NAME?
1941	-	0	34	L3	-	-	#NAME?	-	#NAME?
1942	-	0	34	L3	-	-	#NAME?	-	#NAME?
1943	-	0	34	L3	-	-	#NAME?	-	#NAME?
1944	-	0	34	L3	-	-	#NAME?	-	#NAME?
1945	-	0	34	L3	-	-	#NAME?	-	#NAME?
1946	-	0	34	L3	-	-	#NAME?	-	#NAME?
1947	-	0	34	L3	-	-	#NAME?	-	#NAME?
1948	-	0	34	L3	-	-	#NAME?	-	#NAME?
1949	-	0	34	L3	-	-	#NAME?	-	#NAME?
1950	-	0	34	L3	-	-	#NAME?	-	#NAME?
1951	400	0	34	L3	12	-	#NAME?	-	#NAME?
1952	-	0	34	L3	-	-	#NAME?	-	#NAME?
1953	-	0	34	L3	-	-	#NAME?	-	#NAME?
1954	-	0	34	L3	-	-	#NAME?	-	#NAME?
1955	1,480	0	34	L3	44	-	#NAME?	-	#NAME?
1956	3,602	0	34	L3	106	-	#NAME?	-	#NAME?
1957	814	0	34	L3	24	-	#NAME?	-	#NAME?
1958	199	0	34	L3	6	-	#NAME?	-	#NAME?
1959	500	0	34	L3	15	-	#NAME?	-	#NAME?
1960	488	0	34	L3	14	-	#NAME?	-	#NAME?
1961	1,719	0	34	L3	51	-	#NAME?	-	#NAME?
1962	-	0	34	L3	-	-	#NAME?	-	#NAME?
1963	-	0	34	L3	-	-	#NAME?	-	#NAME?
1964	264	0	34	L3	8	-	#NAME?	-	#NAME?
1965	-	0	34	L3	-	-	#NAME?	-	#NAME?
1966	4,386	0	34	L3	129	-	#NAME?	-	#NAME?
1967	2,857	0	34	L3	84	-	#NAME?	-	#NAME?
1968	798	0	34	L3	23	-	#NAME?	-	#NAME?
1969	64	0	34	L3	2	-	#NAME?	-	#NAME?
1970	19,796	0	34	L3	582	-	#NAME?	-	#NAME?
1971	1,439	0	34	L3	42	-	#NAME?	-	#NAME?



Delta Natural Gas Company  
 Depreciation Study  
 As of June 30, 2002  
 375 -- Distribution Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1972	366	0	34	L3	11	-	#NAME?	-	#NAME?
1973	-	0	34	L3	-	-	#NAME?	-	#NAME?
1974	298	0	34	L3	9	-	#NAME?	-	#NAME?
1975	414	0	34	L3	12	-	#NAME?	-	#NAME?
1976	4,664	0	34	L3	137	-	#NAME?	-	#NAME?
1977	16,625	0	34	L3	489	-	#NAME?	-	#NAME?
1978	-	0	34	L3	-	-	#NAME?	-	#NAME?
1979	2,354	0	34	L3	69	-	#NAME?	-	#NAME?
1980	572	0	34	L3	17	-	#NAME?	-	#NAME?
1981	1,270	0	34	L3	37	-	#NAME?	-	#NAME?
1982	-	0	34	L3	-	-	#NAME?	-	#NAME?
1983	734	0	34	L3	22	-	#NAME?	-	#NAME?
1984	-	0	34	L3	-	-	#NAME?	-	#NAME?
1985	9,863	0	34	L3	290	-	#NAME?	-	#NAME?
1986	6,484	0	34	L3	191	-	#NAME?	-	#NAME?
1987	-	0	34	L3	-	-	#NAME?	-	#NAME?
1988	5,063	0	34	L3	149	-	#NAME?	-	#NAME?
1989	2,806	0	34	L3	83	-	#NAME?	-	#NAME?
1990	779	0	34	L3	23	-	#NAME?	-	#NAME?
1991	-	0	34	L3	-	-	#NAME?	-	#NAME?
1992	7,442	0	34	L3	219	-	#NAME?	-	#NAME?
1993	3,144	0	34	L3	92	-	#NAME?	-	#NAME?
1994	-	0	34	L3	-	-	#NAME?	-	#NAME?
1995	12,893	0	34	L3	379	-	#NAME?	-	#NAME?
1996	3,942	0	34	L3	116	-	#NAME?	-	#NAME?
1997	4,101	0	34	L3	121	-	#NAME?	-	#NAME?
1998	2,265	0	34	L3	67	-	#NAME?	-	#NAME?
1999	3,538	0	34	L3	104	-	#NAME?	-	#NAME?
2000	-	0	34	L3	-	-	#NAME?	-	#NAME?
2001	5,172	0	34	L3	152	-	#NAME?	-	#NAME?
2002	2,756	0	34	L3	81	-	#NAME?	-	#NAME?
2003	2,624	0	34	L3	77	-	#NAME?	-	#NAME?
2004	2,883	0	34	L3	85	-	#NAME?	-	#NAME?

Delta Natural Gas Company  
 Depreciation Study  
 As of June 30, 2002  
 375 -- Distribution Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
2005	1,850	0	34	L3	54	-	#NAME?	-	#NAME?
2006	-	0	34	L3	-	-	#NAME?	-	#NAME?
	143,708	-			4,227	-	#NAME?		#NAME?
Average Remaining Life									
				Survivor Curve					
				ASL					
				L3					
				34					

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Delta Natural Gas Company  
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 As of June 30, 2002  
 376 -- Distribution Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	58,962	0	34	R4	1,734	-	#NAME?	-	#NAME?
1941	-	0	34	R4	-	-	#NAME?	-	#NAME?
1942	-	0	34	R4	-	-	#NAME?	-	#NAME?
1943	-	0	34	R4	-	-	#NAME?	-	#NAME?
1944	-	0	34	R4	-	-	#NAME?	-	#NAME?
1945	-	0	34	R4	-	-	#NAME?	-	#NAME?
1946	-	0	34	R4	-	-	#NAME?	-	#NAME?
1947	75,766	0	34	R4	2,228	-	#NAME?	-	#NAME?
1948	67,865	0	34	R4	1,996	-	#NAME?	-	#NAME?
1949	62,008	0	34	R4	1,824	-	#NAME?	-	#NAME?
1950	29,854	0	34	R4	878	-	#NAME?	-	#NAME?
1951	36,626	0	34	R4	1,077	-	#NAME?	-	#NAME?
1952	18,609	0	34	R4	547	-	#NAME?	-	#NAME?
1953	12,981	0	34	R4	382	-	#NAME?	-	#NAME?
1954	47,353	0	34	R4	1,393	-	#NAME?	-	#NAME?
1955	148,499	0	34	R4	4,368	-	#NAME?	-	#NAME?
1956	143,937	0	34	R4	4,233	-	#NAME?	-	#NAME?
1957	39,727	0	34	R4	1,168	-	#NAME?	-	#NAME?
1958	34,326	0	34	R4	1,010	-	#NAME?	-	#NAME?
1959	106,509	0	34	R4	3,133	-	#NAME?	-	#NAME?
1960	69,660	0	34	R4	2,049	-	#NAME?	-	#NAME?
1961	110,606	0	34	R4	3,253	-	#NAME?	-	#NAME?
1962	71,538	0	34	R4	2,104	-	#NAME?	-	#NAME?
1963	86,884	0	34	R4	2,555	-	#NAME?	-	#NAME?
1964	89,514	0	34	R4	2,633	-	#NAME?	-	#NAME?
1965	123,728	0	34	R4	3,639	-	#NAME?	-	#NAME?
1966	135,264	0	34	R4	3,978	-	#NAME?	-	#NAME?
1967	317,430	0	34	R4	9,336	-	#NAME?	-	#NAME?
1968	182,038	0	34	R4	5,354	-	#NAME?	-	#NAME?
1969	582,335	0	34	R4	17,128	-	#NAME?	-	#NAME?
1970	1,455,571	0	34	R4	42,811	-	#NAME?	-	#NAME?
1971	1,074,050	0	34	R4	31,590	-	#NAME?	-	#NAME?
1972	324,850	0	34	R4	9,554	-	#NAME?	-	#NAME?
1973	448,840	0	34	R4	13,201	-	#NAME?	-	#NAME?
1974	294,232	0	34	R4	8,654	-	#NAME?	-	#NAME?
1975	409,344	0	34	R4	12,040	-	#NAME?	-	#NAME?
1976	201,118	0	34	R4	5,915	-	#NAME?	-	#NAME?
1977	215,318	0	34	R4	6,333	-	#NAME?	-	#NAME?
1978	316,671	0	34	R4	9,314	-	#NAME?	-	#NAME?

Delta Natural Gas Company  
 Depreciation Study  
 As of June 30, 2002  
 376 -- Distribution Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	723,822	0	34	R4	21,289	-	#NAME?	-	#NAME?
1980	646,465	0	34	R4	19,014	-	#NAME?	-	#NAME?
1981	1,960,024	0	34	R4	57,648	-	#NAME?	-	#NAME?
1982	1,666,448	0	34	R4	49,013	-	#NAME?	-	#NAME?
1983	1,579,871	0	34	R4	46,467	-	#NAME?	-	#NAME?
1984	1,436,971	0	34	R4	42,264	-	#NAME?	-	#NAME?
1985	1,581,605	0	34	R4	46,518	-	#NAME?	-	#NAME?
1986	1,840,623	0	34	R4	54,136	-	#NAME?	-	#NAME?
1987	1,938,634	0	34	R4	57,019	-	#NAME?	-	#NAME?
1988	2,392,247	0	34	R4	70,360	-	#NAME?	-	#NAME?
1989	2,519,548	0	34	R4	74,104	-	#NAME?	-	#NAME?
1990	2,464,496	0	34	R4	72,485	-	#NAME?	-	#NAME?
1991	3,124,355	0	34	R4	91,893	-	#NAME?	-	#NAME?
1992	2,153,634	0	34	R4	63,342	-	#NAME?	-	#NAME?
1993	2,518,971	0	34	R4	74,087	-	#NAME?	-	#NAME?
1994	2,398,105	0	34	R4	70,533	-	#NAME?	-	#NAME?
1995	3,191,099	0	34	R4	93,856	-	#NAME?	-	#NAME?
1996	2,627,094	0	34	R4	77,267	-	#NAME?	-	#NAME?
1997	2,772,515	1000	34	R4	81,545	29	#NAME?	#NAME?	#NAME?
1998	4,460,035	0	34	R4	131,178	-	#NAME?	-	#NAME?
1999	3,295,415	0	34	R4	96,924	-	#NAME?	-	#NAME?
2000	3,191,898	0	34	R4	93,879	-	#NAME?	-	#NAME?
2001	1,634,379	6556	34	R4	48,070	193	#NAME?	#NAME?	#NAME?
2002	1,118,713	0	34	R4	32,903	-	#NAME?	-	#NAME?
2003	1,493,803	0	34	R4	43,935	-	#NAME?	-	#NAME?
2004	1,866,444	0	34	R4	54,895	-	#NAME?	-	#NAME?
2005	1,634,459	0	34	R4	48,072	-	#NAME?	-	#NAME?
2006	1,344,632	0	34	R4	39,548	-	#NAME?	-	#NAME?
	66,968,318	7,556			1,969,656	222	#NAME?		#NAME?

Average Remaining Life

Survivor Curve  
ASL

R4  
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Delta Natural Gas Company  
 Depreciation Study  
 As of June 30, 2002

378 -- Measuring Regulating Equipment - General

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	110	0	36	R1	3	-	#NAME?	-	#NAME?
1941	-	0	36	R1	-	-	#NAME?	-	#NAME?
1942	-	0	36	R1	-	-	#NAME?	-	#NAME?
1943	-	0	36	R1	-	-	#NAME?	-	#NAME?
1944	-	0	36	R1	-	-	#NAME?	-	#NAME?
1945	-	0	36	R1	-	-	#NAME?	-	#NAME?
1946	-	0	36	R1	-	-	#NAME?	-	#NAME?
1947	-	0	36	R1	-	-	#NAME?	-	#NAME?
1948	260	0	36	R1	7	-	#NAME?	-	#NAME?
1949	97	0	36	R1	3	-	#NAME?	-	#NAME?
1950	202	0	36	R1	6	-	#NAME?	-	#NAME?
1951	535	0	36	R1	15	-	#NAME?	-	#NAME?
1952	904	0	36	R1	25	-	#NAME?	-	#NAME?
1953	789	0	36	R1	22	-	#NAME?	-	#NAME?
1954	38	0	36	R1	1	-	#NAME?	-	#NAME?
1955	5,199	0	36	R1	144	-	#NAME?	-	#NAME?
1956	3,855	0	36	R1	107	-	#NAME?	-	#NAME?
1957	1,094	0	36	R1	30	-	#NAME?	-	#NAME?
1958	-	0	36	R1	-	-	#NAME?	-	#NAME?
1959	12,372	0	36	R1	344	-	#NAME?	-	#NAME?
1960	-	0	36	R1	-	-	#NAME?	-	#NAME?
1961	-	0	36	R1	-	-	#NAME?	-	#NAME?
1962	321	0	36	R1	9	-	#NAME?	-	#NAME?
1963	-	0	36	R1	-	-	#NAME?	-	#NAME?
1964	608	0	36	R1	17	-	#NAME?	-	#NAME?
1965	881	0	36	R1	24	-	#NAME?	-	#NAME?
1966	5,272	0	36	R1	146	-	#NAME?	-	#NAME?
1967	-	0	36	R1	-	-	#NAME?	-	#NAME?
1968	317	0	36	R1	9	-	#NAME?	-	#NAME?
1969	281	0	36	R1	8	-	#NAME?	-	#NAME?
1970	23,330	0	36	R1	648	-	#NAME?	-	#NAME?
1971	24,948	0	36	R1	693	-	#NAME?	-	#NAME?
1972	13,981	0	36	R1	388	-	#NAME?	-	#NAME?
1973	3,975	0	36	R1	110	-	#NAME?	-	#NAME?
1974	5,207	0	36	R1	145	-	#NAME?	-	#NAME?
1975	6,244	0	36	R1	173	-	#NAME?	-	#NAME?
1976	3,610	0	36	R1	100	-	#NAME?	-	#NAME?
1977	8,552	0	36	R1	238	-	#NAME?	-	#NAME?
1978	7,190	0	36	R1	200	-	#NAME?	-	#NAME?

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 378 -- Measuring Regulating Equipment - General

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	9,000	0	36	R1	250	-	#NAME?	-	#NAME?
1980	41,132	0	36	R1	1,143	-	#NAME?	-	#NAME?
1981	51,901	0	36	R1	1,442	-	#NAME?	-	#NAME?
1982	13,595	0	36	R1	378	-	#NAME?	-	#NAME?
1983	20,919	0	36	R1	581	-	#NAME?	-	#NAME?
1984	16,759	0	36	R1	466	-	#NAME?	-	#NAME?
1985	12,417	0	36	R1	345	-	#NAME?	-	#NAME?
1986	37,728	0	36	R1	1,048	-	#NAME?	-	#NAME?
1987	54,661	0	36	R1	1,518	-	#NAME?	-	#NAME?
1988	57,764	0	36	R1	1,605	-	#NAME?	-	#NAME?
1989	87,102	0	36	R1	2,420	-	#NAME?	-	#NAME?
1990	51,068	0	36	R1	1,419	-	#NAME?	-	#NAME?
1991	44,062	0	36	R1	1,224	-	#NAME?	-	#NAME?
1992	52,625	0	36	R1	1,462	-	#NAME?	-	#NAME?
1993	49,956	0	36	R1	1,388	-	#NAME?	-	#NAME?
1994	44,296	0	36	R1	1,230	-	#NAME?	-	#NAME?
1995	101,062	0	36	R1	2,807	-	#NAME?	-	#NAME?
1996	58,206	0	36	R1	1,617	-	#NAME?	-	#NAME?
1997	116,218	0	36	R1	3,228	-	#NAME?	-	#NAME?
1998	62,585	0	36	R1	1,738	-	#NAME?	-	#NAME?
1999	133,573	0	36	R1	3,710	-	#NAME?	-	#NAME?
2000	8,746	0	36	R1	243	-	#NAME?	-	#NAME?
2001	27,018	0	36	R1	751	-	#NAME?	-	#NAME?
2002	14,796	0	36	R1	411	-	#NAME?	-	#NAME?
2003	132,610	0	36	R1	3,684	-	#NAME?	-	#NAME?
2004	59,940	0	36	R1	1,665	-	#NAME?	-	#NAME?
2005	117,525	0	36	R1	3,265	-	#NAME?	-	#NAME?
2006	21,873	0	36	R1	608	-	#NAME?	-	#NAME?
	1,629,309	-			45,259	-	#NAME?		#NAME?

Average Remaining Life

Survivor Curve  
ASL  
R1 36

Delta Natural Gas Company  
 Depreciation Study  
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 379 -- Measuring Regulating Station Equipment -- City Gate

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	37	R2	-	-	#NAME?	-	#NAME?
1941	-	0	37	R2	-	-	#NAME?	-	#NAME?
1942	-	0	37	R2	-	-	#NAME?	-	#NAME?
1943	-	0	37	R2	-	-	#NAME?	-	#NAME?
1944	-	0	37	R2	-	-	#NAME?	-	#NAME?
1945	-	0	37	R2	-	-	#NAME?	-	#NAME?
1946	-	0	37	R2	-	-	#NAME?	-	#NAME?
1947	-	0	37	R2	-	-	#NAME?	-	#NAME?
1948	-	0	37	R2	-	-	#NAME?	-	#NAME?
1949	-	0	37	R2	-	-	#NAME?	-	#NAME?
1950	626	0	37	R2	17	-	#NAME?	-	#NAME?
1951	498	0	37	R2	13	-	#NAME?	-	#NAME?
1952	-	0	37	R2	-	-	#NAME?	-	#NAME?
1953	-	0	37	R2	-	-	#NAME?	-	#NAME?
1954	424	0	37	R2	11	-	#NAME?	-	#NAME?
1955	4,368	0	37	R2	118	-	#NAME?	-	#NAME?
1956	6,252	0	37	R2	169	-	#NAME?	-	#NAME?
1957	2,928	0	37	R2	79	-	#NAME?	-	#NAME?
1958	415	0	37	R2	11	-	#NAME?	-	#NAME?
1959	1,136	0	37	R2	31	-	#NAME?	-	#NAME?
1960	5,188	0	37	R2	140	-	#NAME?	-	#NAME?
1961	729	0	37	R2	20	-	#NAME?	-	#NAME?
1962	103	0	37	R2	3	-	#NAME?	-	#NAME?
1963	-	0	37	R2	-	-	#NAME?	-	#NAME?
1964	118	0	37	R2	3	-	#NAME?	-	#NAME?
1965	185	0	37	R2	5	-	#NAME?	-	#NAME?
1966	10,334	0	37	R2	279	-	#NAME?	-	#NAME?
1967	1,607	0	37	R2	43	-	#NAME?	-	#NAME?
1968	13	0	37	R2	0	-	#NAME?	-	#NAME?
1969	1,756	0	37	R2	47	-	#NAME?	-	#NAME?
1970	6,102	0	37	R2	165	-	#NAME?	-	#NAME?

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 379 -- Measuring Regulating Station Equipment -- City Gate

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1971	-	0	37	R2	-	-	#NAME?	-	#NAME?
1972	-	0	37	R2	-	-	#NAME?	-	#NAME?
1973	-	0	37	R2	-	-	#NAME?	-	#NAME?
1974	1,289	0	37	R2	35	-	#NAME?	-	#NAME?
1975	-	0	37	R2	-	-	#NAME?	-	#NAME?
1976	1,180	0	37	R2	32	-	#NAME?	-	#NAME?
1977	9,218	0	37	R2	249	-	#NAME?	-	#NAME?
1978	1,634	0	37	R2	44	-	#NAME?	-	#NAME?
1979	32,008	0	37	R2	865	-	#NAME?	-	#NAME?
1980	43,580	0	37	R2	1,178	-	#NAME?	-	#NAME?
1981	10,544	0	37	R2	285	-	#NAME?	-	#NAME?
1982	-	0	37	R2	-	-	#NAME?	-	#NAME?
1983	14,039	0	37	R2	379	-	#NAME?	-	#NAME?
1984	13,765	0	37	R2	372	-	#NAME?	-	#NAME?
1985	69,107	0	37	R2	1,868	-	#NAME?	-	#NAME?
1986	29,155	0	37	R2	788	-	#NAME?	-	#NAME?
1987	41,206	0	37	R2	1,114	-	#NAME?	-	#NAME?
1988	-	0	37	R2	-	-	#NAME?	-	#NAME?
1989	-	0	37	R2	-	-	#NAME?	-	#NAME?
1990	-	0	37	R2	-	-	#NAME?	-	#NAME?
1991	33,855	0	37	R2	915	-	#NAME?	-	#NAME?
1992	8,924	0	37	R2	241	-	#NAME?	-	#NAME?
1993	19,002	0	37	R2	514	-	#NAME?	-	#NAME?
1994	37,494	0	37	R2	1,013	-	#NAME?	-	#NAME?
1995	13,865	0	37	R2	375	-	#NAME?	-	#NAME?
1996	-	0	37	R2	-	-	#NAME?	-	#NAME?
1997	2,853	0	37	R2	77	-	#NAME?	-	#NAME?
1998	-	0	37	R2	-	-	#NAME?	-	#NAME?
1999	14,844	0	37	R2	401	-	#NAME?	-	#NAME?
2000	-	0	37	R2	-	-	#NAME?	-	#NAME?
2001	-	0	37	R2	-	-	#NAME?	-	#NAME?
2002	13,763	0	37	R2	372	-	#NAME?	-	#NAME?





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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	1,300	0	40	S1	33	-	#NAME?	-	#NAME?
1941	-	0	40	S1	-	-	#NAME?	-	#NAME?
1942	-	0	40	S1	-	-	#NAME?	-	#NAME?
1943	-	0	40	S1	-	-	#NAME?	-	#NAME?
1944	-	0	40	S1	-	-	#NAME?	-	#NAME?
1945	-	0	40	S1	-	-	#NAME?	-	#NAME?
1946	-	0	40	S1	-	-	#NAME?	-	#NAME?
1947	1,361	0	40	S1	34	-	#NAME?	-	#NAME?
1948	7,200	0	40	S1	180	-	#NAME?	-	#NAME?
1949	12,983	0	40	S1	325	-	#NAME?	-	#NAME?
1950	11,515	0	40	S1	288	-	#NAME?	-	#NAME?
1951	8,282	0	40	S1	207	-	#NAME?	-	#NAME?
1952	25,195	0	40	S1	630	-	#NAME?	-	#NAME?
1953	4,329	0	40	S1	108	-	#NAME?	-	#NAME?
1954	6,163	0	40	S1	154	-	#NAME?	-	#NAME?
1955	14,171	0	40	S1	354	-	#NAME?	-	#NAME?
1956	29,813	0	40	S1	745	-	#NAME?	-	#NAME?
1957	15,293	0	40	S1	382	-	#NAME?	-	#NAME?
1958	17,188	0	40	S1	430	-	#NAME?	-	#NAME?
1959	19,856	0	40	S1	496	-	#NAME?	-	#NAME?
1960	21,145	0	40	S1	529	-	#NAME?	-	#NAME?
1961	24,843	0	40	S1	621	-	#NAME?	-	#NAME?
1962	14,485	0	40	S1	362	-	#NAME?	-	#NAME?
1963	31,894	0	40	S1	797	-	#NAME?	-	#NAME?
1964	18,103	0	40	S1	453	-	#NAME?	-	#NAME?
1965	23,944	0	40	S1	599	-	#NAME?	-	#NAME?
1966	20,427	0	40	S1	511	-	#NAME?	-	#NAME?
1967	36,960	0	40	S1	924	-	#NAME?	-	#NAME?
1968	44,180	0	40	S1	1,105	-	#NAME?	-	#NAME?
1969	61,872	0	40	S1	1,547	-	#NAME?	-	#NAME?
1970	219,572	0	40	S1	5,489	-	#NAME?	-	#NAME?
1971	210,607	0	40	S1	5,265	-	#NAME?	-	#NAME?
1972	91,736	0	40	S1	2,293	-	#NAME?	-	#NAME?
1973	91,823	0	40	S1	2,296	-	#NAME?	-	#NAME?
1974	58,878	0	40	S1	1,472	-	#NAME?	-	#NAME?
1975	78,982	0	40	S1	1,975	-	#NAME?	-	#NAME?
1976	48,111	0	40	S1	1,203	-	#NAME?	-	#NAME?
1977	66,317	0	40	S1	1,658	-	#NAME?	-	#NAME?

Delta Natural Gas Company  
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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1978	67,406	0	40	S1	1,685	-	#NAME?	-	#NAME?
1979	53,560	0	40	S1	1,339	-	#NAME?	-	#NAME?
1980	69,898	0	40	S1	1,747	-	#NAME?	-	#NAME?
1981	92,069	0	40	S1	2,302	-	#NAME?	-	#NAME?
1982	195,244	0	40	S1	4,881	-	#NAME?	-	#NAME?
1983	125,587	0	40	S1	3,140	-	#NAME?	-	#NAME?
1984	147,259	0	40	S1	3,681	-	#NAME?	-	#NAME?
1985	82,296	0	40	S1	2,057	-	#NAME?	-	#NAME?
1986	81,339	0	40	S1	2,033	-	#NAME?	-	#NAME?
1987	125,529	0	40	S1	3,138	-	#NAME?	-	#NAME?
1988	216,913	0	40	S1	5,423	-	#NAME?	-	#NAME?
1989	86,154	0	40	S1	2,154	-	#NAME?	-	#NAME?
1990	195,258	0	40	S1	4,881	-	#NAME?	-	#NAME?
1991	142,091	0	40	S1	3,552	-	#NAME?	-	#NAME?
1992	105,207	6585	40	S1	2,630	165	#NAME?	#NAME?	#NAME?
1993	281,873	0	40	S1	7,047	-	#NAME?	-	#NAME?
1994	239,405	0	40	S1	5,985	-	#NAME?	-	#NAME?
1995	297,778	0	40	S1	7,444	-	#NAME?	-	#NAME?
1996	1,004,419	0	40	S1	25,110	-	#NAME?	-	#NAME?
1997	94,368	0	40	S1	2,359	-	#NAME?	-	#NAME?
1998	828,908	0	40	S1	20,723	-	#NAME?	-	#NAME?
1999	221,392	0	40	S1	5,535	-	#NAME?	-	#NAME?
2000	203,319	0	40	S1	5,083	-	#NAME?	-	#NAME?
2001	408,435	0	40	S1	10,211	-	#NAME?	-	#NAME?
2002	577,827	0	40	S1	14,446	-	#NAME?	-	#NAME?
2003	1,828,445	0	40	S1	45,711	-	#NAME?	-	#NAME?
2004	92,829	0	40	S1	2,321	-	#NAME?	-	#NAME?
2005	215,473	0	40	S1	5,387	-	#NAME?	-	#NAME?
2006	225,642	0	40	S1	5,641	-	#NAME?	-	#NAME?
	9,644,451	6,585			241,111	165	#NAME?		#NAME?

Average Remaining Life

Survivor Curve  
ASL

S1  
40

Delta Natural Gas Company  
 Depreciation Study  
 As of June 30, 2002  
 382 -- Meter Regulator Installation

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	386	0	40	S1	10	-	#NAME?	-	#NAME?
1941	-	0	40	S1	-	-	#NAME?	-	#NAME?
1942	-	0	40	S1	-	-	#NAME?	-	#NAME?
1943	-	0	40	S1	-	-	#NAME?	-	#NAME?
1944	-	0	40	S1	-	-	#NAME?	-	#NAME?
1945	-	0	40	S1	-	-	#NAME?	-	#NAME?
1946	-	0	40	S1	-	-	#NAME?	-	#NAME?
1947	291	0	40	S1	7	-	#NAME?	-	#NAME?
1948	543	0	40	S1	14	-	#NAME?	-	#NAME?
1949	1,057	0	40	S1	26	-	#NAME?	-	#NAME?
1950	1,120	0	40	S1	28	-	#NAME?	-	#NAME?
1951	1,784	0	40	S1	45	-	#NAME?	-	#NAME?
1952	293	0	40	S1	7	-	#NAME?	-	#NAME?
1953	394	0	40	S1	10	-	#NAME?	-	#NAME?
1954	1,666	0	40	S1	42	-	#NAME?	-	#NAME?
1955	2,929	0	40	S1	73	-	#NAME?	-	#NAME?
1956	8,754	0	40	S1	219	-	#NAME?	-	#NAME?
1957	8,202	0	40	S1	205	-	#NAME?	-	#NAME?
1958	6,222	0	40	S1	156	-	#NAME?	-	#NAME?
1959	4,846	0	40	S1	121	-	#NAME?	-	#NAME?
1960	3,986	0	40	S1	100	-	#NAME?	-	#NAME?
1961	3,306	0	40	S1	83	-	#NAME?	-	#NAME?
1962	9,394	0	40	S1	235	-	#NAME?	-	#NAME?
1963	1,800	0	40	S1	45	-	#NAME?	-	#NAME?
1964	1,800	0	40	S1	45	-	#NAME?	-	#NAME?
1965	2,280	0	40	S1	57	-	#NAME?	-	#NAME?
1966	2,088	0	40	S1	52	-	#NAME?	-	#NAME?
1967	4,152	0	40	S1	104	-	#NAME?	-	#NAME?
1968	5,823	0	40	S1	146	-	#NAME?	-	#NAME?
1969	8,651	0	40	S1	216	-	#NAME?	-	#NAME?
1970	8,413	0	40	S1	210	-	#NAME?	-	#NAME?
1971	6,017	0	40	S1	150	-	#NAME?	-	#NAME?
1972	6,795	0	40	S1	170	-	#NAME?	-	#NAME?
1973	8,877	0	40	S1	222	-	#NAME?	-	#NAME?
1974	5,641	0	40	S1	141	-	#NAME?	-	#NAME?
1975	4,065	0	40	S1	102	-	#NAME?	-	#NAME?
1976	2,843	0	40	S1	71	-	#NAME?	-	#NAME?
1977	2,209	0	40	S1	55	-	#NAME?	-	#NAME?

Delta Natural Gas Company  
 Depreciation Study  
 As of June 30, 2002  
 382 -- Meter Regulator Installation

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1978	1,604	0	40	S1	40	-	#NAME?	-	#NAME?
1979	4,463	0	40	S1	112	-	#NAME?	-	#NAME?
1980	5,200	0	40	S1	130	-	#NAME?	-	#NAME?
1981	12,046	0	40	S1	301	-	#NAME?	-	#NAME?
1982	66,540	0	40	S1	1,664	-	#NAME?	-	#NAME?
1983	99,610	0	40	S1	2,490	-	#NAME?	-	#NAME?
1984	94,296	0	40	S1	2,357	-	#NAME?	-	#NAME?
1985	67,324	0	40	S1	1,683	-	#NAME?	-	#NAME?
1986	69,688	0	40	S1	1,742	-	#NAME?	-	#NAME?
1987	60,219	0	40	S1	1,505	-	#NAME?	-	#NAME?
1988	71,400	0	40	S1	1,785	-	#NAME?	-	#NAME?
1989	89,262	296457	40	S1	2,232	7,411	#NAME?	#NAME?	#NAME?
1990	147,697	0	40	S1	3,692	-	#NAME?	-	#NAME?
1991	118,996	0	40	S1	2,975	-	#NAME?	-	#NAME?
1992	170,332	0	40	S1	4,258	-	#NAME?	-	#NAME?
1993	142,352	0	40	S1	3,559	-	#NAME?	-	#NAME?
1994	160,617	0	40	S1	4,015	-	#NAME?	-	#NAME?
1995	148,177	0	40	S1	3,704	-	#NAME?	-	#NAME?
1996	150,837	0	40	S1	3,771	-	#NAME?	-	#NAME?
1997	149,850	0	40	S1	3,746	-	#NAME?	-	#NAME?
1998	172,095	0	40	S1	4,302	-	#NAME?	-	#NAME?
1999	155,766	0	40	S1	3,894	-	#NAME?	-	#NAME?
2000	122,090	0	40	S1	3,052	-	#NAME?	-	#NAME?
2001	98,891	0	40	S1	2,472	-	#NAME?	-	#NAME?
2002	93,543	0	40	S1	2,339	-	#NAME?	-	#NAME?
2003	102,667	0	40	S1	2,567	-	#NAME?	-	#NAME?
2004	112,534	0	40	S1	2,813	-	#NAME?	-	#NAME?
2005	110,798	0	40	S1	2,770	-	#NAME?	-	#NAME?
2006	82,818	0	40	S1	2,070	-	#NAME?	-	#NAME?
	3,008,339	296,457			75,208	7,411	#NAME?		#NAME?

Average Remaining Life

Survivor Curve  
ASL

S1  
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Delta Natural Gas Company  
 Depreciation Study  
 As of June 30, 2002  
 383 -- House Regulators

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	563	0	28	S6	20	-	#NAME?	-	#NAME?
1941	-	0	28	S6	-	-	#NAME?	-	#NAME?
1942	-	0	28	S6	-	-	#NAME?	-	#NAME?
1943	-	0	28	S6	-	-	#NAME?	-	#NAME?
1944	-	0	28	S6	-	-	#NAME?	-	#NAME?
1945	-	0	28	S6	-	-	#NAME?	-	#NAME?
1946	-	0	28	S6	-	-	#NAME?	-	#NAME?
1947	6,423	0	28	S6	229	-	#NAME?	-	#NAME?
1948	560	0	28	S6	20	-	#NAME?	-	#NAME?
1949	508	0	28	S6	18	-	#NAME?	-	#NAME?
1950	1,192	0	28	S6	43	-	#NAME?	-	#NAME?
1951	3,347	0	28	S6	120	-	#NAME?	-	#NAME?
1952	1,274	0	28	S6	46	-	#NAME?	-	#NAME?
1953	1,063	0	28	S6	38	-	#NAME?	-	#NAME?
1954	1,689	0	28	S6	60	-	#NAME?	-	#NAME?
1955	4,186	0	28	S6	150	-	#NAME?	-	#NAME?
1956	8,755	0	28	S6	313	-	#NAME?	-	#NAME?
1957	6,486	0	28	S6	232	-	#NAME?	-	#NAME?
1958	4,537	0	28	S6	162	-	#NAME?	-	#NAME?
1959	4,836	0	28	S6	173	-	#NAME?	-	#NAME?
1960	5,466	0	28	S6	195	-	#NAME?	-	#NAME?
1961	10,139	0	28	S6	362	-	#NAME?	-	#NAME?
1962	4,564	0	28	S6	163	-	#NAME?	-	#NAME?
1963	8,161	0	28	S6	291	-	#NAME?	-	#NAME?
1964	5,251	0	28	S6	188	-	#NAME?	-	#NAME?
1965	9,372	0	28	S6	335	-	#NAME?	-	#NAME?
1966	5,883	0	28	S6	210	-	#NAME?	-	#NAME?
1967	8,100	0	28	S6	289	-	#NAME?	-	#NAME?
1968	10,199	0	28	S6	364	-	#NAME?	-	#NAME?
1969	15,644	0	28	S6	559	-	#NAME?	-	#NAME?
1970	15,245	0	28	S6	544	-	#NAME?	-	#NAME?
1971	44,148	0	28	S6	1,577	-	#NAME?	-	#NAME?
1972	18,706	0	28	S6	668	-	#NAME?	-	#NAME?
1973	18,408	0	28	S6	657	-	#NAME?	-	#NAME?
1974	29,340	0	28	S6	1,048	-	#NAME?	-	#NAME?
1975	12,375	0	28	S6	442	-	#NAME?	-	#NAME?
1976	18,467	0	28	S6	660	-	#NAME?	-	#NAME?
1977	29,083	0	28	S6	1,039	-	#NAME?	-	#NAME?
1978	20,730	0	28	S6	740	-	#NAME?	-	#NAME?

Delta Natural Gas Company  
 Depreciation Study  
 As of June 30, 2002  
 383 -- House Regulators

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	17,688	0	28	S6	632	-	#NAME?	-	#NAME?
1980	44,258	0	28	S6	1,581	-	#NAME?	-	#NAME?
1981	46,611	0	28	S6	1,665	-	#NAME?	-	#NAME?
1982	62,018	0	28	S6	2,215	-	#NAME?	-	#NAME?
1983	79,203	0	28	S6	2,829	-	#NAME?	-	#NAME?
1984	68,536	0	28	S6	2,448	-	#NAME?	-	#NAME?
1985	82,809	0	28	S6	2,957	-	#NAME?	-	#NAME?
1986	45,980	0	28	S6	1,642	-	#NAME?	-	#NAME?
1987	107,385	3463	28	S6	3,835	124	#NAME?	-	#NAME?
1988	84,581	0	28	S6	3,021	-	#NAME?	-	#NAME?
1989	114,666	0	28	S6	4,095	-	#NAME?	-	#NAME?
1990	112,102	0	28	S6	4,004	-	#NAME?	-	#NAME?
1991	63,398	0	28	S6	2,264	-	#NAME?	-	#NAME?
1992	95,099	0	28	S6	3,396	-	#NAME?	-	#NAME?
1993	152,812	0	28	S6	5,458	-	#NAME?	-	#NAME?
1994	115,494	0	28	S6	4,125	-	#NAME?	-	#NAME?
1995	126,610	0	28	S6	4,522	-	#NAME?	-	#NAME?
1996	114,577	0	28	S6	4,092	-	#NAME?	-	#NAME?
1997	85,933	0	28	S6	3,069	-	#NAME?	-	#NAME?
1998	340,732	295	28	S6	12,169	11	#NAME?	#NAME?	#NAME?
1999	161,756	0	28	S6	5,777	-	#NAME?	-	#NAME?
2000	136,617	0	28	S6	4,879	-	#NAME?	-	#NAME?
2001	84,144	0	28	S6	3,005	-	#NAME?	-	#NAME?
2002	114,466	0	28	S6	4,088	-	#NAME?	-	#NAME?
2003	108,820	0	28	S6	3,886	-	#NAME?	-	#NAME?
2004	115,491	0	28	S6	4,125	-	#NAME?	-	#NAME?
2005	142,384	0	28	S6	5,065	-	#NAME?	-	#NAME?
2006	181,209	0	28	S6	6,472	-	#NAME?	-	#NAME?
	3,340,079	3,758			119,289	134	#NAME?		#NAME?

Average Remaining Life

Survivor Curve  
ASL

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Delta Natural Gas Company  
 Depreciation Study  
 As of June 30, 2002  
 385 -- Industrial Meter Sets

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	43	R1	-	-	#NAME?	-	#NAME?
1941	-	0	43	R1	-	-	#NAME?	-	#NAME?
1942	-	0	43	R1	-	-	#NAME?	-	#NAME?
1943	-	0	43	R1	-	-	#NAME?	-	#NAME?
1944	-	0	43	R1	-	-	#NAME?	-	#NAME?
1945	-	0	43	R1	-	-	#NAME?	-	#NAME?
1946	-	0	43	R1	-	-	#NAME?	-	#NAME?
1947	-	0	43	R1	-	-	#NAME?	-	#NAME?
1948	-	0	43	R1	-	-	#NAME?	-	#NAME?
1949	-	0	43	R1	-	-	#NAME?	-	#NAME?
1950	-	0	43	R1	-	-	#NAME?	-	#NAME?
1951	-	0	43	R1	-	-	#NAME?	-	#NAME?
1952	-	0	43	R1	-	-	#NAME?	-	#NAME?
1953	-	0	43	R1	-	-	#NAME?	-	#NAME?
1954	-	0	43	R1	-	-	#NAME?	-	#NAME?
1955	-	0	43	R1	-	-	#NAME?	-	#NAME?
1956	702	0	43	R1	16	-	#NAME?	-	#NAME?
1957	1,860	0	43	R1	43	-	#NAME?	-	#NAME?
1958	1,172	0	43	R1	27	-	#NAME?	-	#NAME?
1959	366	0	43	R1	9	-	#NAME?	-	#NAME?
1960	1,596	0	43	R1	37	-	#NAME?	-	#NAME?
1961	941	0	43	R1	22	-	#NAME?	-	#NAME?
1962	168	0	43	R1	4	-	#NAME?	-	#NAME?
1963	1,767	0	43	R1	41	-	#NAME?	-	#NAME?
1964	308	0	43	R1	7	-	#NAME?	-	#NAME?
1965	1,098	0	43	R1	26	-	#NAME?	-	#NAME?
1966	1,847	0	43	R1	43	-	#NAME?	-	#NAME?
1967	2,885	0	43	R1	67	-	#NAME?	-	#NAME?
1968	2,179	0	43	R1	51	-	#NAME?	-	#NAME?
1969	1,759	0	43	R1	41	-	#NAME?	-	#NAME?
1970	3,485	0	43	R1	81	-	#NAME?	-	#NAME?
1971	3,084	0	43	R1	72	-	#NAME?	-	#NAME?
1972	2,554	0	43	R1	59	-	#NAME?	-	#NAME?
1973	3,174	0	43	R1	74	-	#NAME?	-	#NAME?
1974	2,543	0	43	R1	59	-	#NAME?	-	#NAME?
1975	1,682	0	43	R1	39	-	#NAME?	-	#NAME?
1976	6,518	0	43	R1	152	-	#NAME?	-	#NAME?
1977	-	0	43	R1	-	-	#NAME?	-	#NAME?
1978	4,035	0	43	R1	94	-	#NAME?	-	#NAME?
1979	3,969	0	43	R1	92	-	#NAME?	-	#NAME?





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Delta Natural Gas Company  
 Depreciation Study  
 As of June 30, 2002  
 390 -- General Plant Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	32	R3	-	-	#NAME?	-	#NAME?
1941	-	0	32	R3	-	-	#NAME?	-	#NAME?
1942	-	0	32	R3	-	-	#NAME?	-	#NAME?
1943	-	0	32	R3	-	-	#NAME?	-	#NAME?
1944	-	0	32	R3	-	-	#NAME?	-	#NAME?
1945	-	0	32	R3	-	-	#NAME?	-	#NAME?
1946	-	0	32	R3	-	-	#NAME?	-	#NAME?
1947	-	0	32	R3	-	-	#NAME?	-	#NAME?
1948	-	0	32	R3	-	-	#NAME?	-	#NAME?
1949	-	0	32	R3	-	-	#NAME?	-	#NAME?
1950	-	0	32	R3	-	-	#NAME?	-	#NAME?
1951	-	0	32	R3	-	-	#NAME?	-	#NAME?
1952	-	0	32	R3	-	-	#NAME?	-	#NAME?
1953	-	0	32	R3	-	-	#NAME?	-	#NAME?
1954	-	0	32	R3	-	-	#NAME?	-	#NAME?
1955	-	0	32	R3	-	-	#NAME?	-	#NAME?
1956	-	0	32	R3	-	-	#NAME?	-	#NAME?
1957	-	0	32	R3	-	-	#NAME?	-	#NAME?
1958	20,586	0	32	R3	643	-	#NAME?	-	#NAME?
1959	27,726	0	32	R3	866	-	#NAME?	-	#NAME?
1960	250	0	32	R3	8	-	#NAME?	-	#NAME?
1961	832	0	32	R3	26	-	#NAME?	-	#NAME?
1962	1,197	0	32	R3	37	-	#NAME?	-	#NAME?
1963	23,367	0	32	R3	730	-	#NAME?	-	#NAME?
1964	357	0	32	R3	11	-	#NAME?	-	#NAME?
1965	10,712	0	32	R3	335	-	#NAME?	-	#NAME?
1966	24,179	0	32	R3	756	-	#NAME?	-	#NAME?
1967	149	0	32	R3	5	-	#NAME?	-	#NAME?
1968	3,179	0	32	R3	99	-	#NAME?	-	#NAME?
1969	94	0	32	R3	3	-	#NAME?	-	#NAME?
1970	37,380	0	32	R3	1,168	-	#NAME?	-	#NAME?
1971	29,546	0	32	R3	923	-	#NAME?	-	#NAME?
1972	11,406	0	32	R3	356	-	#NAME?	-	#NAME?
1973	84,336	0	32	R3	2,636	-	#NAME?	-	#NAME?
1974	480	0	32	R3	15	-	#NAME?	-	#NAME?
1975	700	0	32	R3	22	-	#NAME?	-	#NAME?
1976	2,119	0	32	R3	66	-	#NAME?	-	#NAME?
1977	1,374	0	32	R3	43	-	#NAME?	-	#NAME?

Delta Natl. Gas Company  
 Depreciation Study  
 As of June 30, 2002  
 390 -- General Plant Structures and Improvements

1978	568,930	0	32	R3	17,779	-	#NAME?	-	#NAME?
1979	23,860	0	32	R3	746	-	#NAME?	-	#NAME?
1980	58,518	0	32	R3	1,829	-	#NAME?	-	#NAME?
1981	253,709	0	32	R3	7,928	-	#NAME?	-	#NAME?
1982	171,370	0	32	R3	5,355	-	#NAME?	-	#NAME?
1983	79,384	0	32	R3	2,481	-	#NAME?	-	#NAME?
1984	176,763	0	32	R3	5,524	-	#NAME?	-	#NAME?
1985	198,267	0	32	R3	4,321	-	#NAME?	-	#NAME?
1986	79,344	0	32	R3	2,480	-	#NAME?	-	#NAME?
1987	21,786	0	32	R3	681	-	#NAME?	-	#NAME?
1988	9,828	0	32	R3	307	-	#NAME?	-	#NAME?
1989	158,943	0	32	R3	4,967	-	#NAME?	-	#NAME?
1990	247,667	0	32	R3	7,740	-	#NAME?	-	#NAME?
1991	910	0	32	R3	28	-	#NAME?	-	#NAME?
1992	26,100	0	32	R3	816	-	#NAME?	-	#NAME?
1993	115,754	0	32	R3	3,617	-	#NAME?	-	#NAME?
1994	525,596	0	32	R3	16,425	-	#NAME?	-	#NAME?
1995	62,193	0	32	R3	1,944	-	#NAME?	-	#NAME?
1996	150,022	0	32	R3	4,688	-	#NAME?	-	#NAME?
1997	11,853	0	32	R3	370	-	#NAME?	-	#NAME?
1998	33,458	0	32	R3	1,046	-	#NAME?	-	#NAME?
1999	310,970	0	32	R3	9,718	-	#NAME?	-	#NAME?
2000	21,039	0	32	R3	657	-	#NAME?	-	#NAME?
2001	41,155	0	32	R3	1,286	-	#NAME?	-	#NAME?
2002	1,331,240	0	32	R3	41,601	-	#NAME?	-	#NAME?
2003	489,667	0	32	R3	15,302	-	#NAME?	-	#NAME?
2004	346,841	0	32	R3	10,839	-	#NAME?	-	#NAME?
2005	20,333	0	32	R3	635	-	#NAME?	-	#NAME?
2006	55,450	0	32	R3	1,733	-	#NAME?	-	#NAME?
	5,810,919	-			181,591	-	#NAME?		#NAME?

Average Remaining Life

Survivor Curve  
ASL

R3  
32



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

51. Refer to the response to the Staff's First Request, Item 1. Explain the reason(s) for the reduction in the number of directors from 10 to 8.

RESPONSE:

See response to Item 15.

Sponsoring Witness:

Glenn R. Jennings



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

52. Refer to the response to the Staff's First Request, Item 9.
- a. Concerning the reference to the 2006 Federal Energy Regulatory Commission Form 2, do the financial statements contained in that report incorporate the operational results from Delta's three subsidiaries – Delta Resources, Inc., Delgasco, Inc., and Enpro, Inc.?
  - b. Provide an income statement and balance sheet for the test-year that only reflects Delta's regulated operations, in other words, excludes the financial information associated with the three subsidiaries.

**RESPONSE:**

- a. Yes.
- b. See attached schedules:
  - 1. Income Statement
  - 2. Balance Sheet

Sponsoring Witness:

John B. Brown

**DELTA NATURAL GAS COMPANY, INC.**

**STATEMENT OF INCOME  
12 MONTHS ENDED DECEMBER 31, 2006  
(UNAUDITED)**

<b>OPERATING REVENUES</b>	<u>\$63,515,558</u>
<b>OPERATING EXPENSES AND TAXES</b>	
Gas Purchased	\$38,363,849
Operations	10,822,603
Maintenance	679,744
Depreciation	4,234,739
Property & Other Taxes	1,767,480
Income Taxes	956,300
Total	<u>\$56,824,715</u>
<b>Operating Income</b>	\$ 6,690,843
<b>INTEREST EXPENSES</b>	\$ 4,967,705
<b>NET INCOME</b>	<u>\$ 1,723,138</u>



**DELTA NATURAL GAS COMPANY, INC.**  
**BALANCE SHEET**  
**12 MONTHS ENDED DECEMBER 31, 2006**  
**(UNAUDITED)**

**ASSETS**

Gas Utility Plant, at Cost	\$ 182,615,712
Less - Reserve for Depreciation	<u>61,435,867</u>
Net Gas Plant	\$ <u>121,179,845</u>
Current Assets	
Cash	\$ 385,644
Receivables	11,182,535
Deferred Gas Cost	1,117,889
Gas in Storage, at Average Cost	9,809,341
Materials and Supplies, at first-in, first-out cost	480,166
Prepayments	<u>1,032,803</u>
Total Current Assets	\$ <u>24,008,378</u>
Other Assets	
Cash Surrender Value of Life Insurance	\$ 379,661
Unamortized Expenses	5,704,177
Receivable/Investment in Subsidiaries	8,225,272
Other	<u>5,186,763</u>
Total Other Assets	\$ <u>19,495,873</u>
<b>TOTAL ASSETS</b>	<b>\$ <u>164,684,096</u></b>

**LIABILITIES**

Capitalization	
Common Shareholders' Equity	\$ 52,736,947
Long-Term Debt	<u>58,670,000</u>
Total Capitalization	\$ <u>111,406,947</u>
Current Liabilities	
Notes Payable	\$ 17,146,346
Current Portion of Long-Term Debt	1,200,000
Accounts Payable	4,712,879
Accrued Taxes	498,346
Customers' Deposits	596,453
Refunds Due Customers	1,440
Current Deferred Income Taxes	701,000
Accrued Interest	863,201
Other	<u>952,844</u>
Total Current Liabilities	\$ <u>26,672,509</u>
Deferred Credits & Others	
Deferred Income Taxes	\$ 22,191,088
Deferred Investment Tax Credit	232,100
Regulatory Items	2,491,478
Advances for Construction	1,689,974
Total Deferred Credits and Other	\$ <u>26,604,640</u>
<b>TOTAL LIABILITIES</b>	<b>\$ <u>164,684,096</u></b>



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

53. Refer to the response to the Staff's First Request, Item 10.
- a. Identify each account in the trial balance that is exclusively utilized by the three subsidiaries.
  - b. For any account in the trial balance that is utilized by both Delta's regulated operations and the three subsidiaries, indicate the account and separate the test-year-end balance between the regulated operations and the three subsidiaries.

**RESPONSE:**

- a. The first digit of the account number signifies company name. Therefore, no accounts listed are exclusively utilized by the three subsidiaries. The company codes for the subsidiaries are as follows:

- 2 Delta Resources, Inc.
- 3 Delgasco, Inc.
- 5 Enpro, Inc.

The trial balance provided for the Staff's First Request represents only those accounts of Company 1 – Delta Natural. Therefore, there are no accounts on the trial balance which are exclusively utilized by the subsidiaries.

- b. Delta does not further segregate any of its accounts between parent and subsidiary.

Sponsoring Witness:

John B. Brown



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

54. Refer to the response to the Staff's First Request, Item 16. Delta was requested to provide schedules, in comparative form, showing by months for the test year, and the year preceding the test year, the total company balance in each gas plant and reserve account or subaccount included in Delta's chart of accounts as shown in Format 16. The response did not provide the requested information for the subaccounts of Account No. 108 or the account information for Account Nos. 301 through 399. Provide the originally requested information for Account Nos. 108 and 301 through 399.

RESPONSE:

See attached.

Sponsoring Witness:

John B. Brown











Delta Natural Gas Co., Inc.  
Case No. 2007-00089  
PSC 2nd Request #54

1,365,010 Tran Land & Land Rights	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	56,999	56,999	56,999	56,999	56,999	56,999	56,999	56,999	56,999	56,999	56,999	56,999	683,988
2005	56,999	56,999	56,999	56,999	56,999	56,999	56,999	56,999	56,999	56,999	56,999	56,999	683,988
Increase (Decrease)	0	0	0	0	0	0	0	0	0	0	0	0	0

1,365,020 Tran Rights of Way	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	1,197,756	1,197,756	1,197,756	1,197,756	1,197,806	1,199,506	1,200,534	1,207,059	1,209,375	1,211,707	1,212,507	1,212,507	14,442,025
2005	1,091,732	1,091,736	1,101,188	1,101,272	1,101,272	1,117,530	1,122,554	1,122,554	1,127,705	1,144,602	1,144,602	1,189,300	13,456,047
Increase (Decrease)	106,024	106,020	96,568	96,484	96,534	81,976	77,980	84,505	81,670	67,105	67,905	23,207	985,978

1,365,030 Land Rights Depreciable	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	163,626	163,626	163,626	163,626	163,626	163,626	163,626	163,626	163,626	163,626	163,626	163,626	1,963,512
2005	163,626	163,626	163,626	163,626	163,626	163,626	163,626	163,626	163,626	163,626	163,626	163,626	1,963,512
Increase (Decrease)	0	0	0	0	0	0	0	0	0	0	0	0	0

1,366,000 Tran Structures & Improvements	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	152,933	152,933	152,933	152,933	152,933	180,590	180,590	182,239	182,239	182,239	182,239	182,239	2,037,040
2005	153,944	153,944	153,944	153,944	153,944	153,944	153,944	153,944	153,944	152,933	152,933	152,933	1,844,295
Increase (Decrease)	(1,011)	(1,011)	(1,011)	(1,011)	(1,011)	26,646	26,646	28,295	28,295	29,306	29,306	29,306	192,745

1,367,000 Transmission Mains	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	41,362,597	41,360,314	41,360,314	41,360,314	41,406,904	41,434,956	41,429,806	41,443,096	41,443,096	41,443,096	41,443,096	41,447,022	495,934,626
2005	37,122,181	37,122,181	37,718,105	37,719,712	37,722,732	37,754,192	37,798,671	37,884,704	37,884,704	37,889,610	37,771,179	37,761,179	452,149,150
Increase (Decrease)	4,240,416	4,238,133	3,642,209	3,640,602	3,684,172	3,680,764	3,631,135	3,558,407	3,558,392	3,553,486	3,671,917	3,685,843	44,785,476









1.394.010 Compressed Nat.Gas Stat&Equip	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	283,352	283,352	283,352	283,352	283,352	283,352	283,352	283,352	283,352	283,352	283,352	283,352	3,400,224
2005	283,352	283,352	283,352	283,352	283,352	283,352	283,352	283,352	283,352	283,352	283,352	283,352	3,400,224
Increase (Decrease)	0	0	0	0	0	0	0	0	0	0	0	0	0

1.395.000 Laboratory Equipment	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	185,069	185,069	185,069	185,069	185,069	230,648	230,648	230,648	215,548	215,820	215,820	215,820	2,480,215
2005	188,223	185,069	185,069	185,069	185,069	185,069	185,069	185,069	185,069	185,069	185,069	185,069	2,223,982
Increase (Decrease)	(3,154)	0	0	0	0	45,497	45,579	45,579	30,479	30,751	30,751	30,751	256,233

1.396.000 Power Operated Equipment	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	2,731,664	2,723,034	2,723,034	2,723,034	2,723,034	2,723,034	2,794,584	2,766,969	2,779,542	2,779,542	2,779,542	2,779,542	33,026,555
2005	2,693,673	2,693,673	2,693,673	2,683,198	2,689,129	2,689,129	2,733,144	2,733,144	2,733,144	2,735,687	2,735,687	2,731,664	32,544,945
Increase (Decrease)	37,991	29,361	29,361	39,836	33,905	33,905	61,440	33,825	46,398	43,855	43,855	47,878	481,610

1.397.000 Communication Equipment	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	538,887	535,151	528,229	527,895	527,013	527,013	527,013	526,220	443,788	443,788	443,788	443,788	6,012,840
2005	541,265	541,265	541,265	541,265	541,265	528,653	528,653	528,653	528,903	533,050	533,050	542,602	6,429,889
Increase (Decrease)	(2,378)	(6,114)	(13,036)	(13,370)	(13,985)	(1,640)	(1,640)	(2,433)	(85,115)	(89,262)	(89,262)	(98,814)	(417,049)

1.398.000 Miscellaneous Equip.	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	94,060	93,391	93,391	93,391	90,487	90,487	90,487	90,487	54,238	54,238	54,238	54,238	953,133
2005	91,594	91,594	94,395	94,395	94,395	94,395	94,395	94,395	94,395	94,395	94,395	94,395	1,127,136
Increase (Decrease)	2,466	1,797	(1,004)	(1,004)	(3,908)	(3,908)	(3,908)	(3,908)	(40,157)	(40,157)	(40,157)	(40,157)	(174,005)

1.399.010 Mapping	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
Costs													
2006	662,043	662,043	662,043	662,043	662,043	662,043	662,043	662,043	638,509	638,509	638,509	638,509	7,850,380
2005	662,043	662,043	662,043	662,043	662,043	662,043	662,043	662,043	662,043	662,043	662,043	662,043	7,944,516
Increase	0	0	0	0	0	0	0	0	0				
(Decrease)									(23,534)	(23,534)	(23,534)	(23,534)	(94,136)

1.399.020	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
Computer Software													
2006	1,924,167	1,324,167	1,932,005	1,943,283	1,948,775	2,370,799	2,382,094	2,382,094	2,384,744	2,384,744	2,390,294	2,525,991	26,493,157
2005	2,118,144	2,121,016	2,112,303	2,118,550	2,124,094	1,898,541	1,902,851	1,908,898	1,915,465	1,915,465	1,920,497	1,920,497	23,976,321
Increase						472,258	479,243	473,196	469,279	469,279	469,797	605,494	2,518,836
(Decrease)	(193,977)	(196,849)	(180,298)	(175,267)	(175,319)								

1.399.030	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
Computer Hardware													
2006	984,589	984,589	989,381	981,913	990,340	1,006,170	997,099	979,578	937,029	937,029	937,029	937,029	11,641,775
2005	980,875	989,549	989,549	989,549	989,549	961,864	961,864	961,864	963,739	963,739	963,739	984,589	11,700,469
Increase	3,714				791	44,306	35,235	17,714					
(Decrease)		(4,960)	(20,168)	(7,636)					(26,710)	(26,710)	(26,710)	(47,560)	(58,694)

1.399.031	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
Computerized Office Equip													
2006	259,996	258,411	258,411	258,411	256,348	256,348	256,348	256,348	256,348	255,272	255,272	255,272	3,082,785
2005	259,996	258,411	258,411	258,411	256,348	256,348	256,348	256,348	256,348	255,272	255,272	256,781	2,826,004
Increase													
(Decrease)												(1,509)	



1,108,010 PROV FOR DEPR PLANT IN SERVICE	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	-62,104,573	-62,289,462	-62,529,964	-62,893,108	-63,102,209	-63,315,121	-63,659,495	-63,932,244	-63,598,283	-63,970,490	-64,317,155	-64,674,788	(760,728,257)
2005	-58,720,552	-59,071,679	-59,357,798	-59,584,626	-59,837,914	-59,892,914	-60,187,949	-60,516,299	-60,784,792	-61,147,961	-61,496,531	-61,816,919	(722,736,245)
Increase													
(Decrease)	(3,385,712)	(3,219,482)	(3,173,873)	(3,310,199)	(3,266,021)	(3,423,960)	(3,473,308)	(3,417,718)	(2,815,271)	(2,824,320)	(2,822,423)	(2,859,725)	(37,992,013)

1,108,830 AVC 383 SALVAGE DEPR	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	56,318	56,804	57,291	57,779	58,268	58,757	59,247	59,742	60,239	60,743	61,253	61,766	708,207
2005	51,207	51,646	52,112	52,579	53,053	53,528	54,005	54,482	54,644	54,866	55,347	55,832	643,300
Increase	5,111	5,158	5,178	5,200	5,215	5,229	5,243	5,261	5,594	5,878	5,905	5,935	64,907
(Decrease)													0

1,108,900 AVC 390 SALVAGE DEPR	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	987,789	993,795	997,301	1,003,295	1,009,290	1,015,284	1,021,307	1,027,336	1,033,364	1,039,401	1,045,437	1,051,473	12,225,073
2005	915,779	921,779	927,779	933,779	939,779	945,779	951,780	957,780	963,790	969,788	975,786	981,783	11,385,382
Increase	72,010	72,016	69,522	69,516	69,511	69,505	69,528	69,556	69,574	69,613	69,651	69,690	839,691
(Decrease)													0

1,108,910 AVC 391 SALVAGE DEPR	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	25,538	25,392	25,396	25,400	25,405	25,409	25,413	25,417	25,421	25,426	25,430	25,435	305,082
2005	25,527	25,555	25,283	25,511	25,339	25,367	25,395	25,423	25,450	25,478	25,506	25,534	305,168
Increase	11		114	90	66	42	18						
(Decrease)		(163)						(6)	(29)	(53)	(76)	(99)	(65)

1,108,920 AVC 392 SALVAGE DEPR	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	928,588	874,310	857,079	863,893	828,017	834,449	840,560	845,512	854,444	863,375	865,948	863,643	10,319,838
2005	914,294	922,220	917,090	910,259	876,807	885,054	890,660	898,654	907,048	915,242	923,509	931,864	10,892,901
Increase	14,294												
(Decrease)		(47,910)	(60,011)	(46,367)	(48,790)	(50,605)	(50,080)	(53,342)	(52,604)	(51,866)	(57,561)	(68,221)	(573,063)

1,108,940 A/C 394 SALVAGE DEPR	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	25,886	25,968	26,051	26,135	26,218	26,304	26,390	26,477	26,560	26,647	26,717	26,828	316,541
2005	25,078	25,133	25,187	25,241	25,294	25,348	25,403	25,480	25,561	25,643	25,724	25,805	304,898
Increase (Decrease)	808	835	864	893	924	955	988	1,016	1,045	1,074	1,105	1,135	11,643

1,108,960 A/C 396 SALVAGE DEPR	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	1,088,925	1,091,031	1,093,127	1,091,223	1,093,319	1,095,415	1,097,511	1,091,906	1,094,081	1,096,277	1,098,473	1,100,669	13,131,956
2005	1,064,335	1,066,363	1,068,390	1,070,418	1,072,440	1,074,470	1,076,499	1,078,606	1,080,713	1,082,820	1,084,930	1,086,820	12,906,804
Increase (Decrease)	24,590	24,668	24,736	20,805	20,878	20,945	21,012	13,300	13,368	13,457	13,543	13,849	225,152

1,108,970 A/C 397 SALVAGE DEPR	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	15,262	15,364	15,467	15,569	15,671	15,774	15,876	15,978	16,081	16,184	16,287	16,390	189,903
2005	16,030	16,130	16,230	16,330	16,430	14,560	14,659	14,758	14,858	14,957	15,058	15,158	185,156
Increase (Decrease)	(768)	(766)	(763)	(761)	(758)	1,214	1,217	1,220	1,223	1,227	1,229	1,232	4,747

1,108,980 A/C 398 SALVAGE DEPR	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	4,557	4,561	4,566	4,570	4,575	4,579	4,584	4,588	4,593	4,597	4,602	4,606	54,979
2005	4,505	4,508	4,512	4,517	4,521	4,526	4,530	4,535	4,539	4,544	4,548	4,553	54,337
Increase (Decrease)	52	53	54	54	54	54	54	54	54	54	54	54	642

1,108,993 A/C 39903 SALVAGE DEPR	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12th Month	total
2006	34,639	35,180	34,259	34,792	35,331	35,866	36,421	29,964	30,523	31,079	31,617	32,146	401,817
2005	27,927	28,494	29,068	29,643	30,217	30,772	31,334	31,893	32,452	33,012	33,566	34,099	372,464
Increase (Decrease)	6,713	6,687	5,191	5,150	5,114	5,094	5,087	(1,929)	(1,929)	(1,934)	(1,939)	(1,953)	29,353





**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

55. Refer to the response to the Staff's First Request, Item 18. For each account listed below, explain the reason(s) for the change in the total account balance between the test year and previous 12-month period.
- a. Account No. 480.01 – GS Rate Sales Residential.
  - b. Account No. 480.02 – GS Rate Sales Other Commercial.
  - c. Account No. 480.04 – GS Rate Sales Small Commercial.

RESPONSE:

See attachment.

Sponsoring Witness:

John B. Brown

- a) The reason for the increase in account number 480.01(GS Rate Sales Residential) for calendar 2006 versus 2005 of \$3,288,625 is mainly due to the change in the gas cost recovered through Delta's rates for 2006 versus 2005. After factoring out the gas cost recovered through rates, the actual revenue billed to customers for calendar 2006 actually declined (\$1,173,332) which is attributable to customer conservation and a reduction in the number of customers. See the table below for details.

<u>2006</u>		<u>2005</u>	
Revenue Per G/L	\$34,155,499	Revenue Per G/L	\$30,866,875
Gas Cost recovered	<u>22,943,563</u>	Gas Cost Recovered	<u>18,481,607</u>
Net Revenue	\$11,211,936	Net Revenue	\$12,385,268

- b) The reason for the increase in account number 480.02(GS Rate Sales Other Commercial) for calendar 2006 versus 2005 of \$2,326,875 is mainly due to the change in the gas cost recovered through Delta's rates for 2006 versus 2005. After factoring out the gas cost recovered through rates, the actual revenue billed to customers for calendar 2006 actually declined (\$48,988), which is attributable to customer conservation and a reduction in the number of customers. See the table below for details.

<u>2006</u>		<u>2005</u>	
Revenue Per G/L	\$13,259,071	Revenue Per G/L	\$10,932,196
Gas Cost Recovered	<u>9,926,824</u>	Gas Cost Recovered	<u>7,550,961</u>
Net Revenue	\$ 3,332,247	Net Revenue	\$ 3,381,235

- c) The reason for the increase in account number 480.04(GS Rate Sales Small Commercial) for calendar 2006 versus 2005 of \$1,319,143 is mainly due to the change in the gas cost recovered through Delta's rates for 2006 versus 2005. After factoring out the gas cost recovered through rates, the actual revenue billed to customers for calendar 2006 actually declined (\$226,426), which is attributable to customer conservation and a reduction in the number of customers. See the table below for details.

<u>2006</u>		<u>2005</u>	
Revenue Per G/L	\$10,166,003	Revenue Per G/L	\$8,846,859
Gas Cost Recovered	<u>7,031,328</u>	Gas Cost Recovered	<u>5,485,758</u>
Net Revenue	\$ 3,134,675	Net Revenue	\$3,361,101



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

56. Refer to the response to the Staff's First Request, Item 20(a). For each account listed below, explain the reason(s) for the change in the total account balance between the test year and the previous 12-month period.
- a. Account No. 410.00 – Deferred Income Taxes, sheet 2 of 13.
  - b. Account No. 803.00 – Purchased Gas – Outside, sheet 4 of 13.
  - c. Account No. 926.04 – Medical Coverage, sheet 11 of 13.

RESPONSE:

- a) Deferred income taxes, account (410.00) increased \$935,813 for calendar 2006 versus 2005 mainly due to an increase in deferred income taxes for depreciation over book, which is attributable to additional plant additions.
- b) Purchased gas – outside, account (803.00) increased \$8,700,538 due to the increase in the market price for gas.
- c) Medical coverage, account (926.04) decreased \$362,598 due to the decline in medical claims for calendar 2006 versus calendar 2005.

Sponsoring Witness:

John B. Brown





**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

57. Refer to the response to the Staff's First Request, Item 20(c). Delta was requested to provide a schedule of the total company and Kentucky jurisdictional operations salaries and wages for the test year and each of the 3 calendar years preceding the test year as shown in Format 20c. Delta was also requested to show for each time period the amount of overtime pay. The response to Item 20(c) contains none of the detail requested and does not conform to Format 20c. Provide the originally requested information in the format requested. However, instead of presenting the information on a total company and Kentucky jurisdictional operational basis, provide the information on a total company and regulated operations basis.

**RESPONSE:**

See attached. Line 9 and 10 represents total salaries and wages on a regulated operations basis. Line 12 represents total salaries and wages on a total company basis.

Sponsoring Witness:

John B. Brown

Delta Natural Gas Company, Inc.  
Case No. 2007-00089  
Analysis of Salaries and Wages  
For the Calendar Years 2003 through 2005 and the Test Year

Line No.	Item (a)	Calendar Years Prior to Test Year						Test Year	
		3rd		2nd		1st		Amount (h)	% (i)
		Amount (b)	%	Amount (d)	% (e)	Amount (f)	% (g)		
1.	Wages charged to expense								
2.	Production, Natural Gas Storage, Terminating Processing Expense	132,222	-2.4%	141,723	7.2%	158,323	11.7%	168,979	6.7%
3.	Transmission Expense								
4.	Distribution Expense	2,898,709	-0.9%	3,057,471	5.5%	3,000,635	-1.9%	3,175,422	5.8%
5.	Customer Accounts Expense	362,869	-0.2%	372,665	2.7%	391,234	5.0%	404,578	3.4%
6.	Sales Expense								
7.	Administrative and General Expenses:								
	(a) Administrative and General Salaries	1,306,124	5.7%	1,418,883	8.6%	1,494,606	5.3%	1,612,517	7.9%
	(b) Office Supplies and Expense								
	(c) Administrative Expense transferred - credit								
	(d) Outside services employed								
	(e) Property insurance								
	(f) Injuries and damages								
	(g) Employee pensions and benefits								
	(h) Franchise requirements								
	(i) Regulatory commission expense								
	(j) Duplicate charges - credit								
	(k) Miscellaneous general expense								
	(l) Maintenance of general plant								
8.	Total Administrative and General Expenses - L7(a) through L7(l)	1,306,124	5.7%	1,418,883	8.6%	1,494,606	5.3%	1,612,517	7.9%
9.	Total Salaries and Wages charged expense (L2 through L6 + L8)	4,699,924	0.9%	4,990,742	6.2%	5,044,798	1.1%	5,361,496	6.3%
10.	Wages Capitalized	1,721,213	13.7%	1,450,050	-15.8%	1,583,919	9.2%	1,536,825	-3.0%
11.	Other Accounts	48,592	3.4%	94,017	93.5%	96,195	2.3%	69,003	-28.3%
12.	Total Salaries and Wages	6,469,729	4.0%	6,534,809	1.0%	6,724,912	2.9%	6,967,324	3.6%
13.	Ratio of salaries and wages charged expense to total wages (L9/L12)	0.73		0.76		0.75		0.77	
14.	Ratio of salaries and wages capitalized to total wages (L10/L12)	0.27		0.22		0.24		0.22	
	Overtime	414,993	12.8%	199,718	-51.9%	212,859	6.6%	166,373	-21.8%



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

58. Refer to the response to the Staff's First Request, Item 27(b).
- a. Concerning Account No. 930.01, the director fees and expenses shown on sheets 1 and 2 of 7, provide a schedule by individual listing the compensation for service, cash retainer, chair retainer, committee service retainer, cash performance bonus, and any other thing of value paid to each person serving as a member of Delta's Board of Directors during the test year. Include for each individual the total sum paid by Delta. If any form of compensation to a director was recorded in an account other than Account No. 930.01, provide the same information as requested for Account No. 930.01.
  - b. Concerning Account No. 930.02, industry association dues shown on sheet 2 of 7, describe the nature and purpose of the following organizations and explain why the expense should be included for rate-making purposes.
    - (1) Kentucky Association for Economic Development.
    - (2) Tennessee Oil and Gas Association.
    - (3) National Investor Relations Institute.
    - (4) Associated Industries of Kentucky.
    - (5) Madison County HBA.
    - (6) Tennessee Gas Association.
    - (7) Southeastern Kentucky HBA.
    - (8) Society of Corporate Secretaries.
    - (9) Kentucky Motor Transport Association, Inc.
    - (10) Bluegrass Tomorrow, Inc.
    - (11) BB&T Bankcard Corporation.
    - (12) Commerce Lexington.
  - c. For each of the accounts listed below, additional information is needed concerning the nature or purpose of the expenditures contained in the account. For each account listed, repeat the transaction detail as shown in the response, but organize the transactions by vendor name and describe the nature or purpose of the expenditure instead of referencing "Miscellaneous."
    - (1) Account No. 930.03, sheet 2 of 7.
    - (2) Account No. 930.05, sheets 2 and 3 of 7.
    - (3) Account No. 930.09, sheets 3 and 4 of 7.
  - d. Concerning Account No. 930.11, the miscellaneous expenditures shown on sheets 5 and 6 of 7:

**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

- (1) Reprint the transaction detail as shown in the response, but organize the transactions by vendor name and describe the nature or purpose of the expenditure instead of referencing "Miscellaneous."
- (2) In the November 10, 2004 Order in Case No. 2004-00067, the Commission found that the expenses recorded in Account No. 930.11, Conservation Program, represented promotional advertising and excluded those expenses for rate-making purposes pursuant to the provisions of 807 KAR 5:016, Section 4. Are the expenditures recorded in Account No. 930.11 for this test year essentially the same as the expenditures disallowed in Case No. 2004-00067? If yes, explain why Delta believes these expenditures should be included for rate-making purposes.

**RESPONSE:**

- a. See attached.
- b. (1) Delta participates in order to assist the state and its service area in economic development efforts to help with growth and job creation. Efforts here benefit all Delta's customers when growth occurs and jobs are created or retained.
- (2) Delta participates as some of our transportation volumes go to an interconnected pipeline in Tennessee. This helps us stay better abreast of transportation opportunities, which transportation revenue helps to keep our other rates lower.
- (3) This assists in Delta's efforts to be able to raise equity in a cost effective manner and keep our cost of capital lower.
- (4) Delta has industrial customers that are a significant component of its business. This keeps us better informed of their concerns and assists us in meeting their needs.
- (5) Home builder associations involvement helps us to interact with builders and to stay better informed as to their concerns in order to meet their future needs.
- (6) See response to (2).
- (7) See response to (5).

**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

- (8) Delta is a public, investor-owned company, and must report quarterly to the Securities and Exchange Commission. Information from this organization helps with that.
  - (9) Delta participates with this organization to help obtain information about regulatory requirements as needed relative to Delta's larger trucks and vehicles.
  - (10) Participation keeps us better informed about regional planning and helps support the communities, and thus the customers, involved.
  - (11) This is for membership in the American Institute of Certified Public Accountants for Glenn Jennings, a CPA who is Chairman of the Board, President & CEO. This keeps the company informed in accounting areas, which is important as a publicly-owned company.
  - (12) See response to (10).
- c. See attached.
- d. (1) See attached.
- d. (2) Amounts in account 930.11 are not promotional advertising. They instead represent Delta's conservation program for builders, developers and customers who installed additional gas appliances and received amounts under Delta's incentive program. The benefits of additional sales to these customers are included in the test year in this current rate case and thus revenues are reflected. Therefore, the inclusion of these expenses related thereto should also be included to match revenue and expense. Also, such installations by customers results in conservation of electricity and reduces the need to build expensive generating plants, thus helping everyone as well as Kentucky's environment.

Sponsoring Witness:

Glenn R. Jennings

DELTA NATURAL GAS COMPANY, INC. CASE NO. 2007-00089													
2006 DIRECTORS COMPENSATION													
	G/L Account Number	Crowe Donald	Greer Lanny	Green Jane	Hall Billy Joe	Jennings Glenn R.	Kistner Michael J.	Melton Lewis N.	Peet Harrison D.	Walker Arthur	Whitley Michael	Total	Total
Retainer Fee	193001	11,500.00	11,500.00	9,900.00	11,500.00		11,500.00	11,500.00	13,200.00	11,500.00	11,500.00	103,600.00	103,600.00
Committee Chair Fee	193001						4,800.00	3,600.00				8,400.00	8,400.00
Committee Service Fee	193001	4,800.00	4,800.00	3,300.00	8,100.00		7,200.00	7,200.00		6,900.00	8,300.00	50,600.00	50,600.00
Consulting Fee	192304								24,000.00			24,000.00	24,000.00
Cash Bonus	193001	4,300.00	4,300.00	4,200.00	4,500.00		5,000.00	4,900.00	4,200.00	4,400.00	4,500.00	40,300.00	40,300.00
<b>Total</b>		<b>\$20,600.00</b>	<b>\$20,600.00</b>	<b>\$17,400.00</b>	<b>\$24,100.00</b>	<b>\$ -</b>	<b>\$28,500.00</b>	<b>\$27,200.00</b>	<b>\$41,400.00</b>	<b>\$22,800.00</b>	<b>\$24,300.00</b>	<b>\$226,900.00</b>	<b>\$226,900.00</b>



LINE NO.	VEN NO.	VENDOR NAME	ACCOUNT NO	DATE	TOTAL	CHECK NO.	NATURE OR PURPOSE OF EXPENSE
1	58	AMERICAN EXPRESS	1930030000000000	2006-01-31	425.00	237874	NARUC Winter Committee Meetings - President G. Jennings attend
2	4314	B B & T BANKCARD CORPORATION	1930030000000000	2006-02-28	85.00	238293	Registration 17th Annual Outlook 2006 Conference-G Jennings
3	4314	B B & T BANKCARD CORPORATION	1930030000000000	2006-04-25	175.00	239657	Kentucky Association Education Conference registration Bob Hazelrigg
4	4314	B B & T BANKCARD CORPORATION	1930030000000000	2006-05-30	250.00	240255	Kentucky Gas Association Annual meeting - Glenn Jennings
5	4314	B B & T BANKCARD CORPORATION	1930030000000000	2006-05-30	425.00	240255	NARUC Summer Committee Meetings - President G. Jennings attend
6	4314	B B & T BANKCARD CORPORATION	1930030000000000	2006-06-30	250.00	241051	Kentucky Gas Association Annual meeting - Jeff Steele - Operations
7	4314	B B & T BANKCARD CORPORATION	1930030000000000	2006-10-31	625.00	244130	NARUC - Annual Convention - Bob Hazelrigg
8	4314	B B & T BANKCARD CORPORATION	1930030000000000	2006-10-31	125.00	244130	KAED Registration - Bob Hazelrigg
9	1168	HOME BUILDERS ASSOCIATION OF KY	1930030000000000	2006-01-20	300.00	237405	Commonwealth Builders Conference - Exhibitor Booth Rental
10	1343	KENTUCKY GAS ASSOCIATION	1930030000000000	2006-06-01	1,500.00	240042	Registration for 6 employees to attend KGA Annual Meeting
11	1343	KENTUCKY GAS ASSOCIATION	1930030000000000	2006-06-01	315.00	239761	Kentucky Gas Association Annual meeting - Johnny Caudill-VP
12	1343	KENTUCKY GAS ASSOCIATION	1930030000000000	2006-06-01	250.00	239997	Sponsorship for KGA Annual Meeting
13	1343	KENTUCKY GAS ASSOCIATION	1930030000000000	2006-06-01	250.00	240153	Kentucky Gas Association Annual meeting - Mike Robinson-Dist Mgr
14	0	KIUC	1930030000000000	2006-02-01	300.00	237670	KIUC - KY Ind Utility Conference- Pres G. Jennings; B Ramsey attend
15	1745	NARUC	1930030000000000	2006-04-01	150.00	238828	NARUC Registration John Brown attend conference (CPE hours)
16	1745	NARUC	1930030000000000	2006-09-01	150.00	241735	NARUC - Staff Sub Committee Accounting and Finance-J Hall- VP
17	2126	SEARUC 2006	1930030000000000	2006-06-01	550.00	239285	SEARUC Conference Bob Hazelrigg attend as Industry Participant
18				TOTAL	6,125.00		

DELTA NATURAL GAS COMPANY  
 RATE CASE 2007-00089  
 AC 930.05 YR ENDED 2006

LINE NO	VEN NO	VENDOR NAME	AC NO	DATE	TOTAL	CHECK NO	NATURE OR PURPOSE OF EXPENSE
1	32	ADVERTISING SPECIALTIES	1930050000000000	2006-06-30	2,662.85	241157	Shirts for employees Dec meeting
2	32	ADVERTISING SPECIALTIES	1930050000000000	2006-06-30	485.53	241157	Shirts for employees Dec meeting
3	32	ADVERTISING SPECIALTIES	1930050000000000	2006-06-30	206.96	241157	Shirts for employees Dec meeting
4	32	ADVERTISING SPECIALTIES	1930050000000000	2006-07-21	58.88	241745	Shirts for Continuing Ed meetings
5	32	ADVERTISING SPECIALTIES	1930050000000000	2006-07-28	1,093.82	241745	Thermometers given to employees/customers
6	32	ADVERTISING SPECIALTIES	1930050000000000	2006-10-31	192.84	244057	Recognize employees
7	32	ADVERTISING SPECIALTIES	1930050000000000	2006-10-31	134.58	244057	Recognize employees
8	32	ADVERTISING SPECIALTIES	1930050000000000	2006-10-31	132.46	244057	Recognize employees
9	32	ADVERTISING SPECIALTIES	1930050000000000	2006-10-31	195.49	244057	Recognize employees
10	32	ADVERTISING SPECIALTIES	1930050000000000	2006-10-31	66.23	244057	Recognize employees
11	43	ALLENS FLOWERS & GREENHOUSES INC	1930050000000000	2006-05-31	38.11	240196	Gift/Flowers death employee family member
12	43	ALLENS FLOWERS & GREENHOUSES INC	1930050000000000	2006-08-31	42.35	242680	Gift/Flowers employee family member
13	43	ALLENS FLOWERS & GREENHOUSES INC	1930050000000000	2006-09-30	44.47	243339	Gift/Flowers death employee family member
14	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-03-31	35.00	238877	Gift/Flowers employee family member hospitalized
15	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-04-30	253.76	239657	Gift retirement Margie Sidwell
16	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-04-30	25.99	239657	Gift retirement Margie Sidwell
17	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-04-30	165.92	239675	Gift retirement Margie Sidwell
18	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-05-31	508.26	240255	Retirement luncheon
19	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-06-27	4.01	240965	Retirement gift
20	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-06-27	332.79	240965	Retirement gift
21	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-07-26	102.01	241900	Retirement luncheon
22	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-07-26	388.01	241900	Retirement luncheon
23	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-07-26	10.52	241900	Gift/Flowers death employee family member
24	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-07-26	41.09	241900	Gift/Flowers death employee family member
25	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-07-26	5.37	241900	Retirement luncheon
26	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-08-31	41.58	242614	Gift/Flowers employee family member hospitalized
27	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-09-30	40.00	243448	Gift/Flowers employee hospitalized
28	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-10-26	13.10	244130	Ribbons wrap service awards
29	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-11-28	22.98	244785	Retirement dinner
30	4314	B B & T BANKCARD CORPORATION	1930050000000000	2006-11-30	482.98	244785	Retirement dinner
31	0	BETHANY BOOK ROOM	1930050000000000	2006-02-23	39.17	238107	Gift/Flowers death employee family member
32	0	BETHANY BOOK ROOM	1930050000000000	2006-05-03	39.17	239550	Gift/Flowers death employee family member
33	0	BETHANY BOOK ROOM	1930050000000000	2006-10-26	39.19	244008	Gift/Flowers death employee family member
34	0	CALVARY CHRISTIAN CHURCH	1930050000000000	2006-07-06	50.00	241080	Gift memory of employee family member
35	497	CHAPMAN PRINTING COMPANY INC, THE	1930050000000000	2006-03-31	883.68	239295	Company newsletter
36	497	CHAPMAN PRINTING COMPANY INC, THE	1930050000000000	2006-07-31	883.68	242450	Company newsletter
37	497	CHAPMAN PRINTING COMPANY INC, THE	1930050000000000	2006-12-19	973.28	245337	Company newsletter
38	4593	CRAFT NOOK, THE	1930050000000000	2006-03-31	50.40	238917	Gift/Flowers death employee family member
39	4593	CRAFT NOOK, THE	1930050000000000	2006-04-30	38.15	239572	Gift retirement Margie Sidwell

40	4593	CRAFT NOOK, THE	1930050000000000	2006-05-18	58.99	239980	Gift/Flowers death employee family member	Connie King (Mother)
41	4593	CRAFT NOOK, THE	1930050000000000	2006-05-18	58.99	239980	Gift/Flowers death employee family member	Tom Conlee (Grandmother)
42	4593	CRAFT NOOK, THE	1930050000000000	2006-12-31	45.40	245628	Gift/Flowers death employee family member	CKING DEATH IN FAMILY
43	277	DELTA NATURAL GAS - 02	1930050000000000	2006-08-21	40.00	242197	Gift/Flowers employee family member hospitalized	Employee Kelly Meadows wife
44	866	ESTES, KATHY	1930050000000000	2006-04-13	35.00	239081	Gift/Flowers employee hospitalized	GIFT C SADLER HOSPITAL
45	0	FIRST CHRISTIAN CHURCH OF OWINGSVILLE	1930050000000000	2006-04-17	35.00	239250	Gift/Flowers death employee family member	Yvonne Carpenter's Father
46	0	FIRST CHRISTIAN CHURCH OF OWINGSVILLE	1930050000000000	2006-12-12	100.00	245017	Gift in memory of former Delta Director	ROGER BYRON/FORMER DIRECTOR
47	1132	HENRY'S FLOWER SHOP	1930050000000000	2006-01-31	39.75	237801	Gift/Flowers death employee family member	Kermit Money Father-in-law
48	1132	HENRY'S FLOWER SHOP	1930050000000000	2006-04-30	140.45	239990	Gift/Flowers death employee family member	Employee Cox
49	4665	HOSPICE OF THE BLUE GRASS	1930050000000000	2006-07-07	50.00	241107	Memory Am Meter Rep 25+ years	Anthony Ruggiero
50	1402	KNOX FLORIST	1930050000000000	2006-01-31	47.70	237672	Gift/Flowers death employee family member	Larry Evan's mother (Dorothy Evans)
51		Misc Accts Receivable	1930050000000000	2006-10-31	(20.67)	NA	Reimbursement for shirt	
52	3939	NICHOLASVILLE FLORIST	1930050000000000	2006-05-31	51.41	240496	Gift/Flowers death employee family member	Richard Wells wife
53	1862	PAGES EDITORIAL SERVICE	1930050000000000	2006-12-27	277.30	245405	Company newsletter	DELTA DIGEST
54		PAYROLL	1930050000000000	2006-12-31	3,041.44	NA	Recognize employees	Employee service awards
55	0	RAYANN'S	1930050000000000	2006-12-31	45.05	245948	Gift in memory for former Delta Director	FORMER DIRECTOR MR BYRON
56	2411	TIMES-TRIBUNE, THE	1930050000000000	2006-09-30	325.75	243697	Reclassified to advertising AC 913	
57	4587	TOP DRAWER GALLERY	1930050000000000	2006-11-10	679.70	244472	Recognize employees	Employee Service Awards
58	4618	TURNER, BRENDA	1930050000000000	2006-06-28	72.00	240955	Retirement luncheon	Juanita Hensley Retirement
59				TOTAL	15,947.92			

LINE NO.	VEN NO.	VENDOR NAME	ACCOUNT NO	DATE	TOTAL	CHECK NO.	NATURE OR PURPOSE OF EXPENSE
1	33	ADVOCATE PUBLISHING COMPANY	1930090000000000	2006-07-31	112.64	241967	Barbourville Continuing Education Meeting
2	4412	ADVOCATE-MESSENGER, THE	1930090000000000	2006-09-26	170.40	243197	Nicholasville Continuing Education Meeting
3	4314	B B & T BANKCARD CORPORATION	1930090000000000	2006-07-26	265.63	241900	CONTINUING ED BR 01 - MVA
4	4314	B B & T BANKCARD CORPORATION	1930090000000000	2006-07-26	29.72	241900	Continuing Education Meeting
5	4314	B B & T BANKCARD CORPORATION	1930090000000000	2006-08-30	40.69	242614	Continuing Education Meeting Bell Co
6	4314	B B & T BANKCARD CORPORATION	1930090000000000	2006-08-31	8.55	242614	Continuing Education Public Meeting
7	4314	B B & T BANKCARD CORPORATION	1930090000000000	2006-08-31	138.09	242614	Continuing Education Public Meeting
8	4314	B B & T BANKCARD CORPORATION	1930090000000000	2006-08-31	360.37	242614	Continuing Education Public Meeting
9	4314	B B & T BANKCARD CORPORATION	1930090000000000	2006-09-29	242.98	243448	Continuing Education Public Meeting
10	4314	B B & T BANKCARD CORPORATION	1930090000000000	2006-09-30	30.07	243448	Continuing Education Public Meeting
11	210	BATH COUNTY NEWS OUTLOOK	1930090000000000	2006-06-30	60.80	241063	Owingsville's Continuing Education Meeting
12	210	BATH COUNTY NEWS OUTLOOK	1930090000000000	2006-12-01	12.00	245455	Christmas Greeting
13	256	BEREA CITIZEN, THE	1930090000000000	2006-08-31	88.00	242689	Berea Education Meeting
14	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-01-24	216.90	237876	2006 Meter Reading Schedule
15	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-04-13	2,052.16	239295	Statement Stuffers April 06
16	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-04-30	1,801.81	239829	Statement Stuffers
17	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-05-18	(96.53)	240210	Statement Stuffers
18	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-05-26	2,052.16	240717	Panel Statement Stuffers May 06
19	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-05-31	400.01	240876	Customer Notification Door Hangers
20	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-06-29	2,132.80	241348	Statement Stuffer's June 06
21	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-07-25	2,048.66	242091	Statement Stuffer's July 06
22	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-07-31	2,052.16	242247	Statement Stuffer 2006
23	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-08-31	1,816.63	243135	Statement Stuffer - June 2006
24	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-09-30	1,282.60	243705	Statement Stuffers Oct 06
25	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-10-31	2,052.16	244639	Statement Stuffers Nov 06
26	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-10-31	2,020.10	244639	Important Notice Stuffer Nov 06
27	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-11-30	417.41	245337	Customer Notification Door Hangers
28	497	CHAPMAN PRINTING COMPANY INC, TH	1930090000000000	2006-11-30	1,336.34	245337	Statement Stuffers Dec 06
29	3302	CITIZEN ADVERTISER, THE	1930090000000000	2006-06-30	106.40	241083	Notice of Owingsville's Continuing Education Meeting
30	509	CITIZEN VOICE & TIMES	1930090000000000	2006-09-31	77.76	242700	Manchester Continuing Education
31	1849	DELTA NATURAL GAS - 01	1930090000000000	2006-07-31	36.28	241825	Continuing Education Meeting
32	1796	DELTA NATURAL GAS - 03	1930090000000000	2006-08-24	80.50	242402	Nicholasville Continuing Education Meeting (cookout)
33	1649	DELTA NATURAL GAS - 10	1930090000000000	2006-08-31	14.00	242571	Continuing Education Public Meeting
34	887	ESTILL COUNTY TRIBUNE, THE	1930090000000000	2006-09-17	26.60	242407	Manchester Continuing Education

LINE NO.	VEN NO.	VENDOR NAME	ACCOUNT NO	DATE	TOTAL	CHECK NO.	NATURE OR PURPOSE OF EXPENSE
35	3335	FLEMINGSBURG GAZETTE	1930090000000000	2006-06-30	60.00	241262	Owingsville's Continuing Education Meeting
36	485	GARRARD CENTRAL RECORD, THE	1930090000000000	2006-08-31	80.00	242719	Nicholasville Education Meeting
37	0	HACKER FIRE DEPARTMENT	1930090000000000	2006-07-18	60.00	241573	Donation to Fire Department
38	3092	INTERMOUNTAIN PUBLISHING	1930090000000000	2006-07-31	64.00	241845	Stanton Education Meeting
39	1242	JACKSON COUNTY NEWSGROUP INC.	1930090000000000	2006-08-21	56.00	242417	Manchester Continuing Education
40	1306	JUNIOR ACHIEVEMENT OF THE BLUEGR	1930090000000000	2006-03-17	1,200.00	238740	Junior Achievement Program Donation
41	2653	KENTUCKY INSTITUTE-ECONOMIC DEVEL	1930090000000000	2006-08-31	300.00	242732	Sponsorship
42	4667	LEE PUBLICATIONS INC	1930090000000000	2006-06-30	247.20	241283	Owingsville's Continuing Education Meeting
43	3319	LESLIE COUNTY NEWS, THE	1930090000000000	2006-08-31	108.80	242738	Manchester Continuing Education
44	1473	LXINGTON HERALD-LEADER	1930090000000000	2006-08-17	139.66	242422	Nicholasville Continuing Education Meeting
45	1557	MANCHESTER ENTERPRISE INC	1930090000000000	2006-08-31	112.00	243105	Manchester Continuing Education
46	1645	MIDDLESBORO DAILY NEWS	1930090000000000	2006-07-31	194.56	242215	Middlesboro Continuing Education Meeting
47	4101	MOREHEAD NEWS GROUP	1930090000000000	2006-06-30	243.20	241603	Owingsville's Continuing Education Meeting
48	1720	MT. STERLING ADVOCATE	1930090000000000	2006-07-31	91.04	242217	Stanton Continuing Education Meeting
49	4361	MYRON CORPORATION	1930090000000000	2006-01-18	255.74	237422	Pocket Pals for Transportation Customers
50	4361	MYRON CORPORATION	1930090000000000	2006-11-30	269.12	244912	Pocket Pals for Transportation Customers
51	3487	NATIONAL ENERGY FOUNDATION	1930090000000000	2006-09-30	500.00	243542	NEF Academy for Natural Gas Education
52	1923	PINEVILLE SUN	1930090000000000	2006-07-31	113.60	242049	Middlesboro/Pineville Education Meeting
53	2069	RICHMOND REGISTER	1930090000000000	2006-08-31	195.36	243010	Berea Continuing Education Meeting
54	2152	SENTINEL-ECHO, THE	1930090000000000	2006-07-31	119.20	242228	Corbin Continuing Education Meeting
55	4698	TASCO INDUSTRIES	1930090000000000	2006-10-31	280.85	244146	COPY CHANGE
56	4698	TASCO INDUSTRIES	1930090000000000	2006-10-31	1,788.00	244146	2007 CALENDARS WITH DELTA IMPR
57	2408	THOUSANDSTICKS NEWS, THE	1930090000000000	2006-08-31	108.80	242770	Manchester Continuing Education
58	2409	THREE FORKS TRADITION	1930090000000000	2006-07-31	64.00	241882	Stanton Education Meeting
59	2411	TIMES-TRIBUNE, THE	1930090000000000	2006-07-31	183.20	242235	Corbin Continuing Education Meeting
60	3148	WINCHESTER SUN, THE	1930090000000000	2006-06-30	172.00	241340	Owingsville's Continuing Education Meeting
61				<b>TOTAL</b>	<b>30,493.18</b>		

LINE NO.	VENDOR NO.	VENDOR NAME	ACCOUNT NO	DATE	TOTAL	CHECK NO	NATURE OR PURPOSE OF EXPENSE
1	0	ALEXANDER, MICHAEL	1930110000000000	2006-12-01	300.00	245447	Conservation Program
2	3426	BALL, HOMES INC	1930110000000000	2006-01-05	450.00	236976	Conservation Program
3	3426	BALL, HOMES INC	1930110000000000	2006-01-10	150.00	237139	Conservation Program
4	3426	BALL, HOMES INC	1930110000000000	2006-03-31	250.00	238886	Conservation Program
5	3426	BALL, HOMES INC	1930110000000000	2006-04-30	250.00	239658	Conservation Program
6	3426	BALL, HOMES INC	1930110000000000	2006-05-04	750.00	239658	Conservation Program
7	3426	BALL, HOMES INC	1930110000000000	2006-06-06	750.00	240411	Conservation Program
8	3426	BALL, HOMES INC	1930110000000000	2006-07-12	400.00	241222	Conservation Program
9	3426	BALL, HOMES INC	1930110000000000	2006-08-16	800.00	242179	Conservation Program
10	3426	BALL, HOMES INC	1930110000000000	2006-09-08	250.00	242931	Conservation Program
11	3426	BALL, HOMES INC	1930110000000000	2006-10-18	250.00	243630	Conservation Program
12	3426	BALL, HOMES INC	1930110000000000	2006-11-10	800.00	244403	Conservation Program
13	3426	BALL, HOMES INC	1930110000000000	2006-12-14	250.00	244982	Conservation Program
14	0	BALL, JIMMY	1930110000000000	2006-09-08	150.00	242932	Conservation Program
15	4728	BALL, KERRY	1930110000000000	2006-12-14	150.00	244983	Conservation Program
16	0	BANTA, PATRICK	1930110000000000	2006-09-22	300.00	243199	Conservation Program
17	4712	BANTA, PATRICK	1930110000000000	2006-11-10	200.00	244404	Conservation Program
18	4712	BANTA, PATRICK	1930110000000000	2006-12-14	200.00	244984	Conservation Program
19	0	BENNETT, GARY	1930110000000000	2006-11-21	100.00	244572	Conservation Program
20	0	BISSONNETTE, KATHY	1930110000000000	2006-11-28	250.00	244742	Conservation Program
21	0	BLACKBURN, KEITH	1930110000000000	2006-11-21	200.00	244574	Conservation Program
22	0	BLUEGRASS FINE HOMES	1930110000000000	2006-03-05	300.00	238332	Conservation Program
23	0	CAMPBELL, DEWEY	1930110000000000	2006-02-13	250.00	237757	Conservation Program
24	0	CARPENTER, JIMMY	1930110000000000	2006-09-26	400.00	243210	Conservation Program
25	0	COUCH, HERSHEL	1930110000000000	2006-03-15	300.00	238543	Conservation Program
26	4066	CROUSE, KEVIN	1930110000000000	2006-07-12	2,250.00	241352	Conservation Program
27	4066	CROUSE, KEVIN	1930110000000000	2006-09-08	750.00	242950	Conservation Program
28	4066	CROUSE, KEVIN	1930110000000000	2006-11-08	250.00	244233	Conservation Program
29	4066	CROUSE, KEVIN	1930110000000000	2006-12-14	2,000.00	245109	Conservation Program
30	0	CVM PROPERTIES	1930110000000000	2006-09-08	150.00	242952	Conservation Program
31	0	DAILEY HOMES	1930110000000000	2006-10-18	300.00	243650	Conservation Program
32	4708	DAILY HOMES	1930110000000000	2006-11-08	150.00	244237	Conservation Program
33	0	DEAN, BOBBY	1930110000000000	2006-12-14	200.00	245009	Conservation Program
34	0	ELKINS, JAMES	1930110000000000	2006-12-20	100.00	245281	Conservation Program
35	0	EZ BUILDERS	1930110000000000	2006-11-10	200.00	244435	Conservation Program
36	0	FRENCH, DANNY	1930110000000000	2006-03-31	150.00	238934	Conservation Program
37	0	GABBARD, DON	1930110000000000	2006-01-05	250.00	237017	Conservation Program
38	4287	GAWTHROP, JO	1930110000000000	2006-01-05	200.00	237019	Conservation Program
39	4287	GAWTHROP, JO	1930110000000000	2006-01-10	350.00	237186	Conservation Program
40	4287	GAWTHROP, JO	1930110000000000	2006-04-30	250.00	239584	Conservation Program
41	0	GILREATH, TROY	1930110000000000	2006-05-23	250.00	240118	Conservation Program
42	0	GREENE, ELI	1930110000000000	2006-12-19	100.00	245284	Conservation Program
43	0	HARMONY HOMES	1930110000000000	2006-12-14	300.00	245027	Conservation Program
44	0	HARPE & MASHNI HOMES	1930110000000000	2006-03-05	150.00	238375	Conservation Program
45	4709	HARPE & MASHNI HOMES	1930110000000000	2006-11-08	150.00	244260	Conservation Program
46	4709	HARPE & MASHNI HOMES	1930110000000000	2006-12-14	150.00	245028	Conservation Program
47	0	HATFIELD, MIKE	1930110000000000	2006-11-28	100.00	244754	Conservation Program
48	0	HEUSON, JOHN	1930110000000000	2006-11-21	150.00	244598	Conservation Program

LINE NO.	VENDOR NO.	VENDOR NAME	ACCOUNT NO	DATE	TOTAL	CHECK NO	NATURE OR PURPOSE OF EXPENSE
49	0	HOWARD, GEORGE	1930110000000000	2006-12-20	100.00	245292	Conservation Program
50	0	HUGHES, GARY	1930110000000000	2006-09-11	350.00	242972	Conservation Program
51	4381	J. B. LANG BUILDERS	1930110000000000	2006-01-10	200.00	237196	Conservation Program
52	4263	J. K. HOMES	1930110000000000	2006-03-31	200.00	238951	Conservation Program
53	4263	J. K. HOMES	1930110000000000	2006-05-04	150.00	239592	Conservation Program
54	4263	J. K. HOMES	1930110000000000	2006-06-06	250.00	240471	Conservation Program
55	0	JETT BUILDERS	1930110000000000	2006-11-08	250.00	244267	Conservation Program
56	4727	JETT BUILDERS	1930110000000000	2006-12-14	250.00	245041	Conservation Program
57	0	JONES, ROB	1930110000000000	2006-09-18	150.00	243098	Conservation Program
58	0	JONES, WAVERLY	1930110000000000	2006-09-26	250.00	243228	Conservation Program
59	0	KELLEY, HAROLD	1930110000000000	2006-10-09	250.00	243528	Conservation Program
60	4553	KINDER, DENVER	1930110000000000	2006-06-30	300.00	241114	Conservation Program
61	4553	KINDER, DENVER	1930110000000000	2006-08-21	300.00	242420	Conservation Program
62	4553	KINDER, DENVER	1930110000000000	2006-09-11	250.00	242980	Conservation Program
63	4553	KINDER, DENVER	1930110000000000	2006-12-19	250.00	245299	Conservation Program
64	0	KINDER, STEVE	1930110000000000	2006-01-30	250.00	237669	Conservation Program
65	3643	KNIGHT, BILLY	1930110000000000	2006-12-14	200.00	245051	Conservation Program
66	0	LOCKER, CHARLES	1930110000000000	2006-05-08	350.00	239768	Conservation Program
67	0	MESMER, MIKE	1930110000000000	2006-10-17	250.00	243674	Conservation Program
68	0	MINK, CRAIG	1930110000000000	2006-10-18	400.00	243675	Conservation Program
69	0	O'CONNELL, BOB	1930110000000000	2006-12-14	300.00	245062	Conservation Program
70	3727	PAYNE, KEVIN	1930110000000000	2006-03-27	350.00	238833	Conservation Program
71	4711	PAYNE, KEVIN	1930110000000000	2006-11-10	150.00	244456	Conservation Program
72	0	PHILLIPS, R NICHOLAS	1930110000000000	2006-09-08	250.00	243000	Conservation Program
73	0	POWELL, JIMMY	1930110000000000	2006-11-21	150.00	244611	Conservation Program
74	0	RICE, DREW	1930110000000000	2006-02-09	850.00	237844	Conservation Program
75	4639	RICK MOORE HOMES INC	1930110000000000	2006-03-31	250.00	238993	Conservation Program
76	4639	RICK MOORE HOMES INC	1930110000000000	2006-09-11	250.00	243011	Conservation Program
77	0	ROGERS, JENNIFER	1930110000000000	2006-11-21	100.00	244619	Conservation Program
78	3798	SHORT, RODNEY	1930110000000000	2006-01-10	1,000.00	237273	Conservation Program
79	0	SMITH, LEON	1930110000000000	2006-11-21	100.00	244622	Conservation Program
80	0	SNOW, DAVID	1930110000000000	2006-11-14	200.00	244464	Conservation Program
81	4715	STAR MOUNTAIN DEVELOPMENT LLC	1930110000000000	2006-11-21	1,407.00	244649	Conservation Program
82	4715	STAR MOUNTAIN DEVELOPMENT LLC	1930110000000000	2006-12-14	2,814.00	245126	Conservation Program
83	4433	T & J HOMES LLC	1930110000000000	2006-01-10	150.00	237242	Conservation Program
84	4433	T & J HOMES LLC	1930110000000000	2006-03-31	200.00	239010	Conservation Program
85	4433	T & J HOMES LLC	1930110000000000	2006-05-04	250.00	239635	Conservation Program
86	4433	T & J HOMES LLC	1930110000000000	2006-08-16	200.00	242233	Conservation Program
87	0	TMW CONSTRUCTION	1930110000000000	2006-03-31	150.00	239013	Conservation Program
88	0	W.A.C. BUILDERS	1930110000000000	2006-12-14	750.00	245093	Conservation Program
89	0	WASSON, ADDY	1930110000000000	2006-12-20	100.00	245327	Conservation Program
90	0	WILSON, JAMES	1930110000000000	2006-12-19	100.00	245329	Conservation Program
91	0	WINKLEMAN, JIM	1930110000000000	2006-12-19	100.00	245331	Conservation Program
92	0	WITHROW, DONNA	1930110000000000	2006-10-09	100.00	243582	Conservation Program
93	0	YOUNT CONSTRUCTION	1930110000000000	2006-03-03	150.00	238453	Conservation Program
94	4713	YOUNT CONSTRUCTION	1930110000000000	2006-11-14	100.00	244480	Conservation Program
95		TOTAL			32,821.00		





**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

59. Refer to the response to the Staff's First Request, Item 27(c). Explain in detail why Delta records its donations in Account No. 930.10 instead of Account No. 426.

RESPONSE:

As far as we can tell, it was a decision made when Delta's chart of accounts were originally set up. So, basically, donations are coded to 930.10 because that is the way it has always been done.

Sponsoring Witness:

John B. Brown



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

60. Refer to the response to the Staff's First Request, Item 28. Reprint the transaction detail shown on sheets 1 through 8 of 8 with the data organized by vendor name.

RESPONSE:

See attached.

Sponsoring Witness:

John B. Brown

LINE NO.	VEN N	VENDOR NAME	AC NO	DATE	AMOUNT	CK NUMBER	INV #	INVOICE DESCRIPTION	HRLY RATE	NO HOURS	BUSINESS EXP	BUSINESS EXP DESCRIPTION	TYPE SERVICE
1	3307	COY GILBERT AND GILBERT	192301	2006-03-09	1,000.00	238598	RETAINER FEE	RETAINER FEE	450.00	2.00	2.00	ANNUAL RETAINER FEE	LEGAL
2	958	FULBRIGHT AND JAWORSKI	192301	2006-07-18	902.25	241570	10667264	GENERAL -REVIEW FERC. CORRECTION OF INVOICE				TELEPHONE & DUPLICATING FEES	LEGAL
3	4568	JAMES R. GOLDEN CORRECTION OF INVOICE - FROM AUG AND SEPT. 05	192301	2006-01-31	(5,541.83)							JAMES R. GOLDEN CORRECTION OF INVOICE - FROM AUG AND SEPT. 05	LEGAL
4	4576	MILLER BALIS & O'NEIL P.C.	192301	2006-08-30	1,420.45	243860	15893	TGP - GENERAL	361.00	3.50	157.00	PHOTOCOPIES & TELEPHONE FEES	LEGAL
5	4576	MILLER BALIS & O'NEIL P.C.	192301	2006-10-31	1,189.19	244333	16059	TGP GENERAL MATTERS	361.00	3.19	39.00	PHOTOCOPIES	LEGAL
6	4576	MILLER BALIS & O'NEIL P.C.	192301	2006-12-31	663.15	245678	16339	TGP GENERAL MATTERS	314.00	1.95	50.00	PHOTOCOPIES & TELEPHONE FEES	LEGAL
7	2334	STOLL KEENON AND OGDEN	192301	2006-02-17	995.57	238471	502442	GENERAL-MISCELLANEOUS	281.00	3.60	56.00	TELEPHONE & DUPLICATING FEES	LEGAL
8	2334	STOLL KEENON AND OGDEN	192301	2006-02-22	608.50	238471	504281	GENERAL-MISCELLANEOUS	230.00	2.60	10.00	CERTIFICATE OF EXISTENCE	LEGAL
9	2334	STOLL KEENON AND OGDEN	192301	2006-03-23	1,554.23	238750	FEB 06	GENERAL-MISCELLANEOUS	254.00	5.90	53.00	TELEPHONE & DUPLICATING FEES	LEGAL
10	2334	STOLL KEENON AND OGDEN	192301	2006-04-21	4,982.88	239477	510403	GENERAL-MISCELLANEOUS	206.00	24.10	8.00	TELEPHONE & DUPLICATING FEES	LEGAL
11	2334	STOLL KEENON AND OGDEN	192301	2006-04-21	734.22	239477	510403	EMPLOYEE BENEFITS	281.00	2.60	3.00	TELEPHONE & DUPLICATING FEES	LEGAL
12	2334	STOLL KEENON AND OGDEN	192301	2006-05-18	2,098.44	240050	APRIL 2006	GENERAL-MISCELLANEOUS	172.00	12.10	2.00	TELEPHONE & DUPLICATING FEES	LEGAL
13	2334	STOLL KEENON AND OGDEN	192301	2006-05-18	784.52	240050	APRIL 2006	EMPLOYEE BENEFITS	286.00	3.00	2.00	NO BUSINESS EXPENSE	LEGAL
14	2334	STOLL KEENON AND OGDEN	192301	2006-06-21	1,125.00	240894	MAY 06	GENERAL-MISCELLANEOUS	251.00	4.40	-	TELEPHONE & DUPLICATING FEES	LEGAL
15	2334	STOLL KEENON AND OGDEN	192301	2006-08-23	3,859.60	242470	JUL 06	GENERAL-MISCELLANEOUS	306.00	12.60	4.00	TELEPHONE & DUPLICATING FEES	LEGAL
16	2334	STOLL KEENON AND OGDEN	192301	2006-08-23	1,031.96	242470	JUL 06	EMPLOYEE BENEFITS	281.00	3.90	14.00	TELEPHONE & DUPLICATING FEES	LEGAL
17	2334	STOLL KEENON AND OGDEN	192301	2006-09-22	1,988.26	243280	SEP 06	EMPLOYEE BENEFITS	281.00	7.60	13.00	TELEPHONE & DUPLICATING FEES	LEGAL
18	2334	STOLL KEENON AND OGDEN	192301	2006-09-22	1,327.32	243280	SEP 06	GENERAL-MISCELLANEOUS	205.00	6.40	15.00	TELEPHONE & DUPLICATING FEES	LEGAL
19	2334	STOLL KEENON AND OGDEN	192301	2006-10-24	8,976.01	243959	528234-528235	GENERAL-MISCELLANEOUS	301.00	29.80	1.00	TELEPHONE FEE	LEGAL
20	2334	STOLL KEENON AND OGDEN	192301	2006-10-24	738.78	243959	528234-528235	EMPLOYEE BENEFITS	287.00	2.60	8.00	TELEPHONE FEE	LEGAL
21	2334	STOLL KEENON AND OGDEN	192301	2006-11-21	2,175.40	244651	531295	GENERAL - MISCELLANEOUS	286.00	7.60	1.00	DUPLICATING CHARGES	LEGAL
22	2334	STOLL KEENON AND OGDEN	192301	2006-12-18	2,457.81	245351	534653	GENERAL-MISCELLANEOUS	304.00	8.00	25.00	TELEPHONE & TRAVEL EXPENSE	LEGAL
23	2334	STOLL KEENON AND OGDEN	192301	2006-12-31	1,627.54	246073	DEC 06	EMPLOYEE BENEFITS	281.00	6.20	9.34	TELEPHONE & DUPLICATING FEES	LEGAL
24	2334	STOLL KEENON AND OGDEN	192301	2006-12-31	924.22	246073	DEC 06	EMPLOYEE BENEFITS	281.00	6.20	9.34	TELEPHONE & DUPLICATING FEES	LEGAL
25	2334	STOLL KEENON AND OGDEN	192301	2006-01-31	(12,474.90)			STOLL KEENON AND OGDEN INVOICE REVERSAL FROM DEC 05 WHERE THE S-3 EXPENSE WAS EXPENSED IN ERROR. WHEN THE INVOICE WAS PAID IT WENT CORRECTLY TO CAPITAL STOCK EXPENSE.				STOLL KEENON AND OGDEN - INVOICE REVERSAL FROM DEC 05 WHERE THE S-3 EXPENSE WAS EXPENSED IN ERROR. WHEN THE INVOICE WAS PAID IT WENT CORRECTLY TO CAPITAL STOCK EXPENSE.	LEGAL
26		ACCURED FOR ACCOUNTING SERVICE	192302	VARIOUS	223,834.07			ACCUALS				G/L ENTRY TO ACCRUE FOR ACCOUNTING SERVICES	ACCOUNTING
27	4314	B & T BANKCARD CORPORATION	192302	2006-06-01	990.00	240965	1960 GJ	PREAPPROVED EXPENSES FOR DELOITTE				2006 DELOITTE ENERGY CONFERENCE - MIKE KISTNER	ACCOUNTING
28	4314	B & T BANKCARD CORPORATION	192302	2006-06-01	990.00	240965	1960 GJ	PREAPPROVED EXPENSES FOR DELOITTE				2006 DELOITTE ENERGY CONFERENCE - GLENN JENNINGS	ACCOUNTING
29	4166	DELOITTE AND TOUCHE LLP	192302	2006-01-31	9,990.00	237901	8000082732	OUT OF POCKET EXPENSES ESTIMAT				MEALS & TRAVEL EXPENSES	ACCOUNTING
30	4186	DELOITTE AND TOUCHE LLP	192302	2006-01-31	5,000.00	237901	8000082732	PREAPPROVED TAX RELATED CONSUL		25.00		INCOME TAXES	ACCOUNTING
31	4186	DELOITTE AND TOUCHE LLP	192302	2006-03-31	5,500.00	237076	8000088225	PREAPPROVED AUDIT RELATED SERV				AUDIT RELATED SERVICES	ACCOUNTING
32	4186	DELOITTE AND TOUCHE LLP	192302	2006-05-13	16,800.00	239830	8000166042	PREAPPROVED AUDIT RELATED SERV	200.00	84.00		AUDIT RELATED SERVICES	ACCOUNTING
33	4523	DELOITTE AND TOUCHE PRODUCTS C	192302	2006-05-31	1,500.00	240537	09448537	PREAPPROVED EXPENSES FOR DELOITTE				1 DART SUBSCRIPTION	ACCOUNTING
34	4508	DELOITTE TAX LLP	192302	2006-03-31	500.00	239176	8000159413	PREAPPROVED AUDIT RELATED SERV		2.50		AUDIT	ACCOUNTING
35	2319	STEAMLINER CARPET CLEANER	192303	2006-01-01	2,500.00	237538	CLEANING	CLEANING				JANITORIAL SERVICES	OTHER
36	2319	STEAMLINER CARPET CLEANER	192303	2006-02-01	2,500.00	238175	CLEANING	CLEANING				JANITORIAL SERVICES	OTHER
37	2319	STEAMLINER CARPET CLEANER	192303	2006-03-01	2,500.00	238749	CLEANING	CLEANING				JANITORIAL SERVICES	OTHER
38	2319	STEAMLINER CARPET CLEANER	192303	2006-04-01	2,500.00	239311	CLEANING	CLEANING				JANITORIAL SERVICES	OTHER
39	2319	STEAMLINER CARPET CLEANER	192303	2006-05-01	2,500.00	240146	CLEANING	CLEANING				JANITORIAL SERVICES	OTHER
40	2319	STEAMLINER CARPET CLEANER	192303	2006-06-01	2,500.00	240893	CLEANING	CLEANING				JANITORIAL SERVICES	OTHER
41	2319	STEAMLINER CARPET CLEANER	192303	2006-07-03	2,500.00	241755	CLEANING	CLEANING				JANITORIAL SERVICES	OTHER
42	2319	STEAMLINER CARPET CLEANER	192303	2006-08-01	2,500.00	242469	CLEANING	CLEANING				JANITORIAL SERVICES	OTHER
43	2319	STEAMLINER CARPET CLEANER	192303	2006-09-01	2,500.00	243150	CLEANING	CLEANING				JANITORIAL SERVICES	OTHER
44	2319	STEAMLINER CARPET CLEANER	192303	2006-10-01	2,500.00	243958	CLEANING	CLEANING				JANITORIAL SERVICES	OTHER
45	2319	STEAMLINER CARPET CLEANER	192303	2006-11-01	2,500.00	244650	CLEANING	CLEANING				JANITORIAL SERVICES	OTHER
46	2319	STEAMLINER CARPET CLEANER	192303	2006-12-01	2,500.00	245350	CLEANING	CLEANING				JANITORIAL SERVICES	OTHER
47	3676	CAPITAL LINK CONSULTANTS	192304	2006-10-01	1,000.00	244015	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
48	3676	CAPITAL LINK CONSULTANTS	192304	2006-11-01	1,000.00	244015	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
49	3676	CAPITAL LINK CONSULTANTS	192304	2006-12-01	1,000.00	244322	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
50	3771	CLARK COUNTY HEALTH DEPARTMENT	192304	2006-10-31	1,175.00	244322	FLU SHOTS	FLU SHOTS				FLU SHOTS	OTHER
51	392	COLUMBIA SMALL CUSTOMER GROUP	192304	2006-06-13	6,440.00	240878	1	CONSULTANT				LINDA POSTLEWAITE	OTHER
52	3304	EEO ASSOCIATES	192304	2006-07-31	548.15	242003	11829	LINDA POSTLEWAITE				LINDA POSTLEWAITE	OTHER
53	3304	EEO ASSOCIATES	192304	2006-09-30	799.90	245003	11869	LINDA POSTLEWAITE				LINDA POSTLEWAITE	OTHER
54	4365	ETA ENGINEERING CONSULTANTS PSC	192304	2006-01-24	500.00	237495	2060079	CONSULTING EMERGENCY SHUTDOWN				CONSULTING SERVICES	OTHER
55	1131	HENSLEY, JUANITA	192304	2006-07-03	3,000.00	240974	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER

LINE NO.	VEN N	VENDOR NAME	AC NO	DATE	AMOUNT	CK NUMBER	INV #	INVOICE DESCRIPTION	HRLY RATE	NO HOURS	BUSINESS EXP	BUSINESS EXP DESCRIPTION	TYPE SERVICE
56	1131	HENSLEY, JUANITA	192304	2006-08-01	3,000.00	241779	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
57	1131	HENSLEY, JUANITA	192304	2006-09-01	3,000.00	242545	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
58	1131	HENSLEY, JUANITA	192304	2006-10-01	3,000.00	243268	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
59	1131	HENSLEY, JUANITA	192304	2006-11-01	3,000.00	244021	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
60	1131	HENSLEY, JUANITA	192304	2006-12-01	3,000.00	244730	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
61	4153	MERCER HUMAN RESOURCE CONSULT	192304	2006-10-18	1,037.00	243717	134010003626	COMPENSATION STUDY				COMPENSATION CONSULTING	OTHER
62	4153	MERCER HUMAN RESOURCE CONSULT	192304	2006-10-31	30,500.00	244492	134010003748	COMPENSATION STUDY				COMPENSATION CONSULTING	OTHER
63	1890	PEET, H D	192304	2006-01-01	2,000.00	236950	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
64	1890	PEET, H D	192304	2006-02-01	2,000.00	237612	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
65	1890	PEET, H D	192304	2006-03-01	2,000.00	238206	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
66	1890	PEET, H D	192304	2006-04-01	2,000.00	238866	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
67	1890	PEET, H D	192304	2006-05-01	2,000.00	239476	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
68	1890	PEET, H D	192304	2006-06-01	2,000.00	240188	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
69	1890	PEET, H D	192304	2006-07-03	2,000.00	240981	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
70	1890	PEET, H D	192304	2006-08-01	2,000.00	241783	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
71	1890	PEET, H D	192304	2006-09-01	2,000.00	242549	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
72	1890	PEET, H D	192304	2006-10-01	2,000.00	243274	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
73	1890	PEET, H D	192304	2006-11-01	2,000.00	244025	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
74	1890	PEET, H D	192304	2006-12-01	2,000.00	244733	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
75	3955	QUEST DIAGNOSTICS	192304	2006-04-30	1,117.00	239659	042806	MEDICAL				MEDICAL SERVICES	OTHER
76	2840	SIDWELL, MARJORIE	192304	2006-10-17	640.00	243610	200024	CONSULTANT				CONSULTING SERVICES	OTHER
77	4138	URGENT TREATMENT CLINIC	192304	2006-03-31	3,500.00	239315	900130135556	MEDICAL				MEDICAL SERVICES	OTHER
78	4138	URGENT TREATMENT CLINIC	192304	2006-04-30	1,785.50	240051	900130135556	MEDICAL				MEDICAL SERVICES	OTHER
79	4138	URGENT TREATMENT CLINIC	192304	2006-06-22	1,827.00	240897	900130135556	MEDICAL				MEDICAL SERVICES	OTHER
80	4138	URGENT TREATMENT CLINIC	192304	2006-08-31	1,485.15	243151	ALIG 06	MEDICAL				MEDICAL SERVICES	OTHER
81	4138	URGENT TREATMENT CLINIC	192304	2006-09-30	2,085.45	243721	900130135556	MEDICAL				MEDICAL SERVICES	OTHER
82	4138	URGENT TREATMENT CLINIC	192304	2006-12-31	678.00	245955	900130135556	MEDICAL				MEDICAL SERVICES	OTHER
83	4596	WHITLEY COUNTY HEALTH DEPTARTE	192304	2006-11-22	506.00	244633	FLU SHOTS	MEDICAL				MEDICAL SERVICES	OTHER
84	2635	YARBER, EUNICE	192304	2006-01-01	700.00	236928	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
85	2635	YARBER, EUNICE	192304	2006-02-01	700.00	237601	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
86	2635	YARBER, EUNICE	192304	2006-03-01	700.00	238193	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
87	2635	YARBER, EUNICE	192304	2006-04-01	700.00	238848	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
88	2635	YARBER, EUNICE	192304	2006-05-01	700.00	239452	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
89	2635	YARBER, EUNICE	192304	2006-06-01	700.00	240176	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
90	2635	YARBER, EUNICE	192304	2006-07-03	700.00	240963	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
91	2635	YARBER, EUNICE	192304	2006-08-01	700.00	241768	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
92	2635	YARBER, EUNICE	192304	2006-09-01	700.00	242537	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
93	2635	YARBER, EUNICE	192304	2006-10-01	700.00	243255	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
94	2635	YARBER, EUNICE	192304	2006-11-01	700.00	244014	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
95	2635	YARBER, EUNICE	192304	2006-12-01	700.00	244723	CONSULTING	CONSULTANT				CONSULTING SERVICES	OTHER
96	4404	ALLIANCE DATA SYSTEMS INC	192305	2006-01-06	11,289.00	237072	URCM000117	ECIS SOFTWARE MAINTENANCE AND				SOFTWARE MAINTENANCE	OTHER
97	4404	ALLIANCE DATA SYSTEMS INC	192305	2006-04-15	11,289.00	239166	URCM000214	ECIS SOFTWARE MAINTENANCE AND				SOFTWARE MAINTENANCE	OTHER
98	4404	ALLIANCE DATA SYSTEMS INC	192305	2006-07-02	11,289.00	240964	URCM000304	ECIS SOFTWARE MAINTENANCE AND				SOFTWARE MAINTENANCE	OTHER
99	4404	ALLIANCE DATA SYSTEMS INC	192305	2006-10-01	11,289.00	243447	URCM000398	ECIS SOFTWARE MAINTENANCE AND				SOFTWARE MAINTENANCE	OTHER
100	4669	AMERICAN INNOVATIONS	192305	2006-07-31	1,564.93	242242	A10114221	CATHODIC PROTECTION				SOFTWARE MAINTENANCE	OTHER
101	109	ARSENALUT ASSOCIATES	192305	2006-07-28	1,687.55	241770	0609-19	RENEWAL OF ANNUAL SOFTWARE MAI				SOFTWARE MAINTENANCE	OTHER
102	4314	B & T BANKCARD CORPORATION	192305	2006-06-30	673.70	241051	1950 DT	SOFTWARE MAINTENANCE - DT				SOFTWARE MAINTENANCE	OTHER
103	4673	BERBEE INFORMATION NETWORKS CC	192305	2006-07-28	1,871.45	241746	IN00102228	SOFTWARE MAINTENANCE				SOFTWARE MAINTENANCE	OTHER
104	0	BOX LAKE NETWORKS INC.	192305	2006-08-28	765.00	242693	7395	UPDATES TO WEBSITE				WEB SITE DESIGN PLANNING	OTHER
105	4512	BUSINESS SOLUTIONS GROUP INC.	192305	2006-01-31	600.00	237896	2948	IT CONSULTING				CONSULTING SERVICES	OTHER
106	4512	BUSINESS SOLUTIONS GROUP INC.	192305	2006-02-28	675.00	238294	3025	IT CONSULTING				CONSULTING SERVICES	OTHER
107	4512	BUSINESS SOLUTIONS GROUP INC.	192305	2006-04-23	1,162.60	239294	3095	IT CONSULTING				CONSULTING SERVICES	OTHER
108	4512	BUSINESS SOLUTIONS GROUP INC.	192305	2006-04-23	955.00	239294	3109	IT CONSULTING				CONSULTING SERVICES	OTHER
109	3813	CDW DIRECT LLC	192305	2006-01-31	610.42	237638	VW33712	ADOBE AROBAT STANDARD VERSION				GAS SUPPLY DEPARTMENT	OTHER
110	3813	CDW DIRECT LLC	192305	2006-01-31	610.42	237761	VW33712	ADOBE AROBAT STANDARD VERSION				GAS SUPPLY DEPARTMENT	OTHER
111	3813	CDW DIRECT LLC	192305	2006-03-19	735.62	238690	VW69795	WINDOWS 2003 SERVER FOR EXCHAN				EXCHANGE AGENT	OTHER
112	3813	CDW DIRECT LLC	192305	2006-03-31	1,200.00	239172	XH67050	ETRUST RENEWAL AGREEMENT				SUPPORT & UPDATES	OTHER
113	3813	CDW DIRECT LLC	192305	2006-04-30	1,093.87	239827	XV63917	WINDOWS SERVER 2003 LICENSE				EXCHANGE & UPGRADE LICENSE	OTHER
114	3813	CDW DIRECT LLC	192305	2006-05-31	795.98	240427	ZJ16282	EXCHANGE AGENT FOR EXCHANGE SE				EXCHANGE AGENT	OTHER
115	3813	CDW DIRECT LLC	192305	VARIOUS	7,678.25			MONTHLY EXPENSE OF SOFTWARE MAINTENANCE				SOFTWARE MAINTENANCE	OTHER
116	3813	CDW DIRECT LLC	192305	2006-08-14	756.83	242474	BMH7554	SOFTWARE MAINTENANCE				SOFTWARE MAINTENANCE	OTHER

LINE NO.	VEN N	VENDOR NAME	AC NO	DATE	AMOUNT	CK NUMBER	INV #	INVOICE DESCRIPTION	HRLY RATE	NO HOURS	BUSINESS EXP	BUSINESS EXP DESCRIPTION	TYPE SERVICE
117	4196	CITRIX SYSTEMS INC	192305	2006-02-28	1,575.00	238296	90331605	RENEW SUBSCRIPTION ADVANTAGE F				ONE YEAR SUBSCRIPTION	OTHER
118	3764	COGNOS CORPORATION	192305	2006-05-31	804.54	240661	224974	IMPROVING SUPPORT THROUGH 11/2				STANDARD SUPPORT RENEWAL	OTHER
119	3764	COGNOS CORPORATION	192305	2006-12-13	8,469.40	245107	238838	POWERPLAY AND REPORTNET SUPPOR				SUPPORT SERVICES	OTHER
120	4606	CT CORPORATION	192305	2006-04-01	2,962.70	237453	2387264-SI	EDGAR SERVICE SUBSCRIPTION				SUBSCRIPTION	OTHER
121	3803	DATATRADE LLC	192305	2006-07-02	4,464.00	240969	2006-319	SPOOLVIEW ANNUAL MAINTENANCE'S				ANNUAL MAINTENANCE	OTHER
122	4097	DIGITAL DESIGNS INC.	192305	2006-05-01	1,350.00	239460	10554	FORMSERVER/400 ANNUAL MAINTENA				ANNUAL MAINTENANCE	OTHER
123	4097	DIGITAL DESIGNS INC.	192305	2006-10-01	1,875.00	243591	10963	DOCAGENT ANNUAL MAINTENANCE 10				ANNUAL MAINTENANCE	OTHER
124	4674	FILENET CORPORATION	192305	VARIOUS	1,335.60			MONTHLY EXPENSE OF FILENET CONTENT SERVICES, WEB				ANNUAL SOFTWARE SUPPORT	OTHER
125	4674	FILENET CORPORATION	192305	2006-08-21	5,342.40	242780	70070089	FILENET CONTENT SERVICES, WEB				ANNUAL SOFTWARE SUPPORT	OTHER
126	4674	FILENET CORPORATION	192305	2006-08-31	5,342.40	242541	85068766	FILENET CONTENT SERVICES, WEB				ANNUAL SOFTWARE SUPPORT	OTHER
127	3508	GROUP 1 SOFTWARE	192305	2006-06-01	14,464.89	239467	REN0009920	CODE-1 PLUS, MAILSTREAM PLUS,				U.S. POSTAL MONTHLY DATABASE	OTHER
128	4566	HARRIS INC	192305	2006-01-01	16,476.00	236658	MN00005625	ANNUAL CLASSIC SOFTWARE SUPPORT				SOFTWARE SUPPORT	OTHER
129	4429	HAWKEYE INFORMATION SYSTEMS INC	192305	2006-09-01	650.00	242576	64265	PATHFINDER SERVICES				SUPPORT SERVICES	OTHER
130	4019	IBM	192305	2006-01-01	779.00	236404	D810531	IBM BUSINESS RECOVERY CONTRACT				RECOVERY CONTRACT	OTHER
131	4019	IBM	192305	2006-01-30	779.00	237499	1610550	IBM BUSINESS RECOVERY CONTRACT				RECOVERY CONTRACT	OTHER
132	4019	IBM	192305	2006-03-01	779.00	237938	2610519	IBM BUSINESS RECOVERY CONTRACT				RECOVERY CONTRACT	OTHER
133	4019	IBM	192305	2006-04-01	779.00	238554	3610518	IBM BUSINESS RECOVERY CONTRACT				RECOVERY CONTRACT	OTHER
134	4019	IBM	192305	2006-05-01	779.00	239433	4610530	IBM BUSINESS RECOVERY CONTRACT				RECOVERY CONTRACT	OTHER
135	4019	IBM	192305	2006-06-01	779.00	239835	5610522	IBM BUSINESS RECOVERY CONTRACT				RECOVERY CONTRACT	OTHER
136	4019	IBM	192305	2006-07-01	779.00	240470	6610529	IBM BUSINESS RECOVERY CONTRACT				RECOVERY CONTRACT	OTHER
137	4019	IBM	192305	2006-08-01	779.00	241365	7610545	IBM BUSINESS RECOVERY CONTRACT				RECOVERY CONTRACT	OTHER
138	4019	IBM	192305	2006-09-01	779.00	242209	8610522	IBM BUSINESS RECOVERY CONTRACT				RECOVERY CONTRACT	OTHER
139	4019	IBM	192305	2006-10-01	779.00	243093	9610507	IBM BUSINESS RECOVERY CONTRACT				RECOVERY CONTRACT	OTHER
140	4019	IBM	192305	2006-11-01	779.00	243828	0610521	IBM BUSINESS RECOVERY CONTRACT				RECOVERY CONTRACT	OTHER
141	4019	IBM	192305	2006-12-01	779.00	244440	N810507	IBM BUSINESS RECOVERY CONTRACT				RECOVERY CONTRACT	OTHER
142	3583	INTRASOURCE PREPAYMENTS	192305	VARIOUS	3,250.00			MONTHLY EXPENSE				SOFTWARE MAINTENANCE	OTHER
143	3285	ITRON INC	192305	2006-01-19	592.80	237367	283678 2A	SYSTEM SOFTWARE SUPPORT				SOFTWARE SUPPORT	OTHER
144	3285	ITRON INC	192305	2006-04-28	973.41	239470	293845 2A	SYSTEM SOFTWARE SUPPORT				SOFTWARE SUPPORT	OTHER
145	3285	ITRON INC	192305	2006-12-31	653.49	245432	321507 2A	SOFTWARE MAINTENANCE				SOFTWARE MAINTENANCE	OTHER
146	3285	ITRON INC	192305	2006-10-17	653.49	243613	302440	SOFTWARE MAINTENANCE				SOFTWARE MAINTENANCE	OTHER
147	3265	ITRON INC	192305	2006-11-27	729.04	244642	310905 2A	SOFTWARE MAINTENANCE				SOFTWARE MAINTENANCE	OTHER
148	4307	KNOWLEDGELAKE INC.	192305	2006-10-01	5,760.00	242251	200201350	KNOWLEDGELAKE PINNACLE TABLE				ANNUAL MAINTENANCE	OTHER
149	4382	PINNACLE BUSINESS SYSTEMS INC.	192305	2006-03-31	828.00	238876	4460	ICOM/400 ANNUAL SOFTWARE MAINT.				SOFTWARE MAINTENANCE	OTHER
150	4325	PROTIVITI INC.	192305	2006-06-31	10,000.00	243053	030466	ANNUAL SARBOX PORTAL MAINTENAN				ANNUAL MAINTENANCE	OTHER
151	4655	TCG AMERICA LLC	192305	2006-05-31	1,850.00	240576	2393	IT CONSULTING				CONSULTING SERVICES	OTHER
152	4655	TCG AMERICA LLC	192305	2006-06-21	1,025.00	240896	2428	IT CONSULTING				CONSULTING SERVICES	OTHER
153	4655	TCG AMERICA LLC	192305	2006-07-24	1,375.00	241653	2526	IT CONSULTING				CONSULTING SERVICES	OTHER
154	4655	TCG AMERICA LLC	192305	2006-08-12	525.00	242069	2563	IT CONSULTING				CONSULTING SERVICES	OTHER
155	4655	TCG AMERICA LLC	192305	2006-09-27	825.00	243247	2619	IT CONSULTING				CONSULTING SERVICES	OTHER
156	4655	TCG AMERICA LLC	192305	2006-11-20	800.00	244469	2691	IT CONSULTING				CONSULTING SERVICES	OTHER
157	4655	TCG AMERICA LLC	192305	2006-11-21	1,975.00	244652	2700	IT CONSULTING				CONSULTING SERVICES	OTHER
158	Less than \$500												LEGAL
159	3917	ARMSTRONG TEASDALE LLP	192301	2006-02-28	19.41	238214	1006216	LEGAL FEES-BLUE SKY III					LEGAL

LINE NO.	VEN N	VENDOR NAME	AC NO	DATE	AMOUNT	CK NUMBER	INV #	INVOICE DESCRIPTION	HRLY RATE	NO HOURS	BUSINESS EXP	BUSINESS EXP DESCRIPTION	TYPE SERVICE
160	958	FULLBRIGHT AND JAWORSKI	192301	2006-04-30	205.60	239987	10646587	GENERAL MATTERS					LEGAL
161	4576	MILLER BALLS & O'NEIL P.C.	192301	2006-01-31	223.10	237829	14595	TGP GENERAL MATTERS					LEGAL
162	4576	MILLER BALLS & O'NEIL P.C.	192301	2006-02-24	214.32	239282	14692	TGP GENERAL MATTERS					LEGAL
163	4576	MILLER BALLS & O'NEIL P.C.	192301	2006-04-16	116.87	239269	14863	GENERAL TGP					LEGAL
164	4576	MILLER BALLS & O'NEIL P.C.	192301	2006-04-30	202.48	240004	15048	TGP GROUP					LEGAL
165	4576	MILLER BALLS & O'NEIL P.C.	192301	2006-05-22	72.88	240127	15131	TGP GENERAL MATTERS					LEGAL
166	4576	MILLER BALLS & O'NEIL P.C.	192301	2006-06-30	56.54	241124	15388	TGP GENERAL MATTERS					LEGAL
167	4576	MILLER BALLS & O'NEIL P.C.	192301	2006-07-31	148.08	242039	15554	TGP GENERAL MATTERS					LEGAL
168	4576	MILLER BALLS & O'NEIL P.C.	192301	2006-08-31	247.50	242745	15696	TGP - GENERAL					LEGAL
169	4082	SAUNDERS, DARRELL L.	192301	2006-03-31	225.00	239142	MAR 06	JANITORIAL					LEGAL
170	4082	SAUNDERS, DARRELL L.	192301	2006-06-30	112.50	241360	GENERAL 6/06	JANITORIAL					LEGAL
171	4082	SAUNDERS, DARRELL L.	192301	2006-07-31	150.00	242266	GENERAL 7/06	JANITORIAL					LEGAL
172	2334	STOLL KEENON AND OGDEN	192301	2006-01-23	47.70	237893	500419	EMPLOYEE RELATIONS					LEGAL
173	2334	STOLL KEENON AND OGDEN	192301	2006-02-17	208.80	238471	502434	EMPLOYEE RELATIONS					LEGAL
174	2334	STOLL KEENON AND OGDEN	192301	2006-03-21	104.40	238750	505597	EMPLOYEE RELATIONS					LEGAL
175	2334	STOLL KEENON AND OGDEN	192301	2006-03-23	392.64	238750	FEB 06	EMPLOYEE BENEFITS					LEGAL
176	2334	STOLL KEENON AND OGDEN	192301	2006-04-21	118.35	239477	510403	MISCELLANEOUS					LEGAL
177	2334	STOLL KEENON AND OGDEN	192301	2006-07-21	104.40	240894	MAY 06	EMPLOYEE BENEFITS					LEGAL
178	2334	STOLL KEENON AND OGDEN	192301	2006-07-21	137.71	241742	518394	GENERAL					LEGAL
179	2334	STOLL KEENON AND OGDEN	192301	2006-09-30	78.30	243566	525326	GENERAL					LEGAL
180	4598	BAKER, TERRY L	192303	2006-01-24	160.00	237479	JAN 06	Employee Relations					OTHER
181	4598	BAKER, TERRY L	192303	2006-02-21	160.00	238103	FEB 06	JANITORIAL					OTHER
182	4598	BAKER, TERRY L	192303	2006-03-28	160.00	238785	MAR 06	JANITORIAL					OTHER
183	4598	BAKER, TERRY L	192303	2006-04-25	160.00	239414	APR 06	JANITORIAL					OTHER
184	4598	BAKER, TERRY L	192303	2006-05-30	160.00	240148	CLN CORBIN WH	JANITORIAL					OTHER
185	4598	BAKER, TERRY L	192303	2006-06-27	160.00	240905	CLEANING 6/06	JANITORIAL					OTHER
186	4598	BAKER, TERRY L	192303	2006-07-26	160.00	241705	JUL 06	JANITORIAL					OTHER
187	4598	BAKER, TERRY L	192303	2006-08-30	160.00	242559	AUG 06	JANITORIAL					OTHER
188	4598	BAKER, TERRY L	192303	2006-09-30	160.00	243347	CLEANING	JANITORIAL					OTHER
189	4598	BAKER, TERRY L	192303	2006-10-27	160.00	244063	CLEANING	JANITORIAL					OTHER
190	4598	BAKER, TERRY L	192303	2006-11-30	160.00	244739	NOV 06	JANITORIAL					OTHER
191	4598	BAKER, TERRY L	192303	2006-12-31	160.00	245453	CLEANING	JANITORIAL					OTHER
192	3971	BIRDDOG'S CLEANING SERVICE	192303	2006-03-31	50.00	239058	1383	JANITORIAL					OTHER
193	3971	BIRDDOG'S CLEANING SERVICE	192303	2006-06-30	70.00	241230	1434	JANITORIAL					OTHER
194	3971	BIRDDOG'S CLEANING SERVICE	192303	2006-08-31	60.00	242690	1468	JANITORIAL					OTHER
195	3971	BIRDDOG'S CLEANING SERVICE	192303	2006-10-31	50.00	244212	1517	JANITORIAL					OTHER
196	3971	BIRDDOG'S CLEANING SERVICE	192303	2006-12-01	50.00	245609	1557	JANITORIAL					OTHER
197	4028	BLACK, CATHY	192303	2006-01-31	300.00	237630	JAN 06	JANITORIAL					OTHER
198	4028	BLACK, CATHY	192303	2006-02-28	455.00	238223	FEB 06	JANITORIAL					OTHER
199	4028	BLACK, CATHY	192303	2006-03-31	455.00	238892	MAR 06	JANITORIAL					OTHER
200	4028	BLACK, CATHY	192303	2006-04-30	455.00	239551	APR 06	JANITORIAL					OTHER
201	4028	BLACK, CATHY	192303	2006-05-31	455.00	240206	MAY 06	JANITORIAL					OTHER
202	4028	BLACK, CATHY	192303	2006-06-30	455.00	241232	JUN 06	JANITORIAL					OTHER
203	4028	BLACK, CATHY	192303	2006-07-31	455.00	241800	JUL 06	JANITORIAL					OTHER
204	4028	BLACK, CATHY	192303	2006-08-29	455.00	242558	AUG 06	JANITORIAL					OTHER
205	4028	BLACK, CATHY	192303	2006-09-30	455.00	243358	SEP 06	JANITORIAL					OTHER
206	4028	BLACK, CATHY	192303	2006-10-31	455.00	244071	CLEANING OCT	JANITORIAL					OTHER
207	4028	BLACK, CATHY	192303	2006-11-30	455.00	244851	NOV 06	JANITORIAL					OTHER
208	4028	BLACK, CATHY	192303	2006-12-28	455.00	245461	CLEANING 12/06	JANITORIAL					OTHER
209	601	COMMERCIAL CLEANING SERVICE	192303	2006-05-24	300.00	240111	FLOORMACHES	JANITORIAL					OTHER
210	3933	DEZARN, SUE	192303	2006-01-18	52.50	237400	1/13/06 1/20/06	JANITORIAL					OTHER
211	3933	DEZARN, SUE	192303	2006-01-31	52.50	237649	1/27/06 2/3/06	JANITORIAL					OTHER
212	3933	DEZARN, SUE	192303	2006-02-16	52.50	237927	2/10/06 2/17/06	JANITORIAL					OTHER
213	3933	DEZARN, SUE	192303	2006-02-28	52.50	238238	2/24/06 3/3/06	JANITORIAL					OTHER
214	3933	DEZARN, SUE	192303	2006-03-16	52.50	238546	3/10/06 3/17/06	JANITORIAL					OTHER
215	3933	DEZARN, SUE	192303	2006-03-29	52.50	238809	3/24/06 3/31/06	JANITORIAL					OTHER
216	3933	DEZARN, SUE	192303	2006-04-13	52.50	239077	4/7/06 4/14/06	JANITORIAL					OTHER
217	3933	DEZARN, SUE	192303	2006-04-26	52.50	239430	4/21/06 4/28/06	JANITORIAL					OTHER
218	3933	DEZARN, SUE	192303	2006-05-10	52.50	239738	5/5/06 5/12/06	JANITORIAL					OTHER
219	3933	DEZARN, SUE	192303	2006-05-24	52.50	240115	CLN 5/19-5/26	JANITORIAL					OTHER
220	3933	DEZARN, SUE	192303	2006-06-07	52.50	240448	6/2/06 6/9/06	JANITORIAL					OTHER
221	3933	DEZARN, SUE	192303	2006-06-21	52.50	240831	6/16/06 6/23/06	JANITORIAL					OTHER
222	3933	DEZARN, SUE	192303	2006-06-30	52.50	241092	6/30/06 7/7/06	JANITORIAL					OTHER
223	3933	DEZARN, SUE	192303	2006-07-19	52.50	241560	7/14/06 7/21/06	JANITORIAL					OTHER
224	3933	DEZARN, SUE	192303	2006-07-31	52.50	241826	7/28/06 8/4/06	JANITORIAL					OTHER
225	3933	DEZARN, SUE	192303	2006-08-16	52.50	242199	8/11/06 8/18/06	JANITORIAL					OTHER
226	3933	DEZARN, SUE	192303	2006-08-30	52.50	242572	AUG 06	JANITORIAL					OTHER
227	3933	DEZARN, SUE	192303	2006-09-14	52.50	242954	9/8/06 9/15/06	JANITORIAL					OTHER
228	3933	DEZARN, SUE	192303	2006-09-28	52.50	243216	9/22/06 9/29/06	JANITORIAL					OTHER
229	3933	DEZARN, SUE	192303	2006-10-12	52.50	243499	10/06-10/13	JANITORIAL					OTHER
230	3933	DEZARN, SUE	192303	2006-10-26	52.50	243899	10/20-10/27	JANITORIAL					OTHER
231	3933	DEZARN, SUE	192303	2006-11-08	52.50	244239	11/3 11/10/06	JANITORIAL					OTHER
232	3933	DEZARN, SUE	192303	2006-11-22	52.50	244588	11/17 11/24/06	JANITORIAL					OTHER



LINE NO.	VEN #	VENDOR NAME	AC NO	DATE	AMOUNT	CK NUMBER	INV #	INVOICE DESCRIPTION	HRLY RATE	NO HOURS	BUSINESS EXP	BUSINESS EXP DESCRIPTION	TYPE SERVICE
233	3933	DEZARN, SUE	192303	2006-12-06	52.50	244872	1201-12/08	JANITORIAL					OTHER
234	3933	DEZARN, SUE	192303	2006-12-20	52.50	245273	1215-12/22/06	JANITORIAL					OTHER
235	3933	DEZARN, SUE	192303	2006-12-31	52.50	245483	1229 1/5/2007	JANITORIAL					OTHER
236	3876	DOWNS, ANDREA	192303	2006-01-04	105.00	237494	012601	JANITORIAL					OTHER
237	3876	DOWNS, ANDREA	192303	2006-02-01	105.00	238122	012602	JANITORIAL					OTHER
238	3876	DOWNS, ANDREA	192303	2006-03-01	105.00	238701	012603	JANITORIAL					OTHER
239	3876	DOWNS, ANDREA	192303	2006-04-01	105.00	239245	012604	JANITORIAL					OTHER
240	3876	DOWNS, ANDREA	192303	2006-05-01	105.00	240117	012605	JANITORIAL					OTHER
241	3876	DOWNS, ANDREA	192303	2006-06-01	105.00	240833	012606	JANITORIAL					OTHER
242	3876	DOWNS, ANDREA	192303	2006-07-01	105.00	241561	012607	JANITORIAL					OTHER
243	3876	DOWNS, ANDREA	192303	2006-08-01	105.00	242405	012608	JANITORIAL					OTHER
244	3876	DOWNS, ANDREA	192303	2006-09-01	105.00	243066	012609	JANITORIAL					OTHER
245	3876	DOWNS, ANDREA	192303	2006-10-01	105.00	243902	012610	JANITORIAL					OTHER
246	3876	DOWNS, ANDREA	192303	2006-11-01	105.00	244592	012611	JANITORIAL					OTHER
247	1066	HALL, GARY K	192303	2006-12-01	105.00	245278	012612	JANITORIAL					OTHER
248	1066	HALL, GARY K	192303	2006-01-26	105.00	237498	050145	JANITORIAL					OTHER
249	1066	HALL, GARY K	192303	2006-02-16	105.00	238128	050147	JANITORIAL					OTHER
250	1066	HALL, GARY K	192303	2006-03-31	105.00	238812	05-0154	JANITORIAL					OTHER
251	1066	HALL, GARY K	192303	2006-04-21	105.00	239251	05-0155	JANITORIAL					OTHER
252	1066	HALL, GARY K	192303	2006-05-16	105.00	240119	05158	JANITORIAL					OTHER
253	1066	HALL, GARY K	192303	2006-06-30	105.00	241270	050162	JANITORIAL					OTHER
254	1066	HALL, GARY K	192303	2006-07-31	105.00	241835	050163	JANITORIAL					OTHER
255	1066	HALL, GARY K	192303	2006-08-29	105.00	242575	050168	JANITORIAL					OTHER
256	1066	HALL, GARY K	192303	2006-09-29	105.00	243391	050169	JANITORIAL					OTHER
257	1066	HALL, GARY K	192303	2006-10-09	105.00	243907	050172	JANITORIAL					OTHER
258	1066	HALL, GARY K	192303	2006-11-07	105.00	244597	050174	JANITORIAL					OTHER
259	1066	HALL, GARY K	192303	2006-12-01	105.00	245286	050177	JANITORIAL					OTHER
260	4151	HOMETOWN SERVICE	192303	2006-01-31	300.00	237660	451037	JANITORIAL					OTHER
261	4151	HOMETOWN SERVICE	192303	2006-01-31	300.00	237660	451041	JANITORIAL					OTHER
262	4151	HOMETOWN SERVICE	192303	2006-01-31	150.00	237660	451038	JANITORIAL					OTHER
263	4151	HOMETOWN SERVICE	192303	2006-01-31	150.00	237660	451039	JANITORIAL					OTHER
264	4151	HOMETOWN SERVICE	192303	2006-02-28	300.00	238383	090058	JANITORIAL					OTHER
265	4151	HOMETOWN SERVICE	192303	2006-02-28	300.00	238383	090059	JANITORIAL					OTHER
266	4151	HOMETOWN SERVICE	192303	2006-02-28	150.00	238383	090056	JANITORIAL					OTHER
267	4151	HOMETOWN SERVICE	192303	2006-02-28	150.00	238383	090057	JANITORIAL					OTHER
268	4151	HOMETOWN SERVICE	192303	2006-03-30	300.00	238814	090076	JANITORIAL					OTHER
269	4151	HOMETOWN SERVICE	192303	2006-03-30	150.00	238814	090078	JANITORIAL					OTHER
270	4151	HOMETOWN SERVICE	192303	2006-03-30	75.00	238814	090077	JANITORIAL					OTHER
271	4151	HOMETOWN SERVICE	192303	2006-03-31	300.00	238814	090081	JANITORIAL					OTHER
272	4151	HOMETOWN SERVICE	192303	2006-04-30	300.00	239569	090090	JANITORIAL					OTHER
273	4151	HOMETOWN SERVICE	192303	2006-04-30	300.00	239569	090091	JANITORIAL					OTHER
274	4151	HOMETOWN SERVICE	192303	2006-04-30	150.00	239569	090091	JANITORIAL					OTHER
275	4151	HOMETOWN SERVICE	192303	2006-04-30	150.00	239569	090092	JANITORIAL					OTHER
276	4151	HOMETOWN SERVICE	192303	2006-05-31	300.00	240226	230357	JANITORIAL					OTHER
277	4151	HOMETOWN SERVICE	192303	2006-05-31	300.00	240226	230359	JANITORIAL					OTHER
278	4151	HOMETOWN SERVICE	192303	2006-06-30	150.00	240226	230358	JANITORIAL					OTHER
279	4151	HOMETOWN SERVICE	192303	2006-06-30	300.00	241105	230379	JANITORIAL					OTHER
280	4151	HOMETOWN SERVICE	192303	2006-06-30	300.00	241105	230380	JANITORIAL					OTHER
281	4151	HOMETOWN SERVICE	192303	2006-06-30	150.00	241105	230377	JANITORIAL					OTHER
282	4151	HOMETOWN SERVICE	192303	2006-06-30	150.00	241105	230378	JANITORIAL					OTHER
283	4151	HOMETOWN SERVICE	192303	2006-07-31	300.00	241842	230388	JANITORIAL					OTHER
284	4151	HOMETOWN SERVICE	192303	2006-07-31	285.00	241842	230391	JANITORIAL					OTHER
285	4151	HOMETOWN SERVICE	192303	2006-07-31	150.00	241842	230389	JANITORIAL					OTHER
286	4151	HOMETOWN SERVICE	192303	2006-07-31	150.00	241842	230390	JANITORIAL					OTHER
287	4151	HOMETOWN SERVICE	192303	2006-08-29	300.00	242577	409409	JANITORIAL					OTHER
288	4151	HOMETOWN SERVICE	192303	2006-08-29	265.00	242577	409408	JANITORIAL					OTHER
289	4151	HOMETOWN SERVICE	192303	2006-08-29	150.00	242577	409410	JANITORIAL					OTHER
290	4151	HOMETOWN SERVICE	192303	2006-08-29	150.00	242577	409411	JANITORIAL					OTHER
291	4151	HOMETOWN SERVICE	192303	2006-08-29	300.00	243394	409426	JANITORIAL					OTHER
292	4151	HOMETOWN SERVICE	192303	2006-08-29	300.00	243394	409429	JANITORIAL					OTHER
293	4151	HOMETOWN SERVICE	192303	2006-08-29	150.00	243394	409427	JANITORIAL					OTHER
294	4151	HOMETOWN SERVICE	192303	2006-08-29	150.00	243394	409428	JANITORIAL					OTHER
295	4151	HOMETOWN SERVICE	192303	2006-10-31	300.00	244092	409442	JANITORIAL					OTHER
296	4151	HOMETOWN SERVICE	192303	2006-10-31	300.00	244092	409444	JANITORIAL					OTHER
297	4151	HOMETOWN SERVICE	192303	2006-10-31	150.00	244092	409446	JANITORIAL					OTHER
298	4151	HOMETOWN SERVICE	192303	2006-10-31	150.00	244092	409447	JANITORIAL					OTHER
299	4151	HOMETOWN SERVICE	192303	2006-11-28	300.00	244952	347858	JANITORIAL					OTHER
300	4151	HOMETOWN SERVICE	192303	2006-11-30	300.00	244755	347855	JANITORIAL					OTHER
301	4151	HOMETOWN SERVICE	192303	2006-11-30	150.00	244755	347856	JANITORIAL					OTHER
302	4151	HOMETOWN SERVICE	192303	2006-11-30	150.00	244755	347857	JANITORIAL					OTHER
303	4151	HOMETOWN SERVICE	192303	2006-12-29	300.00	245391	347870	JANITORIAL					OTHER
304	4151	HOMETOWN SERVICE	192303	2006-12-29	150.00	245391	347871	JANITORIAL					OTHER
305	4151	HOMETOWN SERVICE	192303	2006-12-29	150.00	245391	347872	JANITORIAL					OTHER



LINE NO.	VEN #	VENDOR NAME	AC NO	DATE	AMOUNT	CK NUMBER	INV #	INVOICE DESCRIPTION	HRLY RATE	NO HOURS	BUSINESS EXP	BUSINESS EXP DESCRIPTION	TYPE SERVICE
306	4151	HOMETOWN SERVICE	192303	2005-12-31	300.00	245654	347873	JANITORIAL				JANITORIAL	OTHER
307	2077	RILEY LAWRENCE	192303	2006-01-03	275.00	237515	033017	JANITORIAL				JANITORIAL	OTHER
308	2077	RILEY LAWRENCE	192303	2006-02-01	275.00	238145	033018	JANITORIAL				JANITORIAL	OTHER
309	2077	RILEY LAWRENCE	192303	2006-03-01	275.00	238723	033019	JANITORIAL				JANITORIAL	OTHER
310	2077	RILEY LAWRENCE	192303	2006-04-01	275.00	239291	033020	JANITORIAL				JANITORIAL	OTHER
311	2077	RILEY LAWRENCE	192303	2006-05-01	275.00	240134	053021	JANITORIAL				JANITORIAL	OTHER
312	2077	RILEY LAWRENCE	192303	2006-06-01	275.00	240864	033022	JANITORIAL				JANITORIAL	OTHER
313	2077	RILEY LAWRENCE	192303	2006-07-01	275.00	241616	033047	JANITORIAL				JANITORIAL	OTHER
314	2077	RILEY LAWRENCE	192303	2006-08-01	275.00	242431	033048	JANITORIAL				JANITORIAL	OTHER
315	2077	RILEY LAWRENCE	192303	2006-09-01	275.00	243114	033049	JANITORIAL				JANITORIAL	OTHER
316	2077	RILEY LAWRENCE	192303	2006-10-01	275.00	243925	033050	JANITORIAL				JANITORIAL	OTHER
317	2077	RILEY LAWRENCE	192303	2006-11-01	275.00	244617	033051	JANITORIAL				JANITORIAL	OTHER
318	2077	RILEY LAWRENCE	192303	2006-12-01	275.00	245313	033052	JANITORIAL				JANITORIAL	OTHER
319	4158	RUSSELL RICK	192303	2006-01-19	330.00	237516	587041	JANITORIAL				JANITORIAL	OTHER
320	4158	RUSSELL RICK	192303	2006-02-16	330.00	238148	587047	JANITORIAL				JANITORIAL	OTHER
321	4158	RUSSELL RICK	192303	2006-03-20	330.00	238725	587203	JANITORIAL				JANITORIAL	OTHER
322	4158	RUSSELL RICK	192303	2006-04-18	330.00	239283	587209	JANITORIAL				JANITORIAL	OTHER
323	4158	RUSSELL RICK	192303	2006-05-24	330.00	240136	587215	JANITORIAL				JANITORIAL	OTHER
324	4158	RUSSELL RICK	192303	2006-06-28	330.00	240950	JUNE 06	JANITORIAL				JANITORIAL	OTHER
325	4158	RUSSELL RICK	192303	2006-07-18	330.00	241739	587227	JANITORIAL				JANITORIAL	OTHER
326	4158	RUSSELL RICK	192303	2006-08-21	330.00	242536	587231	JANITORIAL				JANITORIAL	OTHER
327	4158	RUSSELL RICK	192303	2006-09-25	330.00	243116	587239	JANITORIAL				JANITORIAL	OTHER
328	4158	RUSSELL RICK	192303	2006-10-17	330.00	243927	587245	JANITORIAL				JANITORIAL	OTHER
329	4158	RUSSELL RICK	192303	2006-11-16	330.00	244620	587250	JANITORIAL				JANITORIAL	OTHER
330	4158	RUSSELL RICK	192303	2006-12-19	330.00	245315	241807	JANITORIAL				JANITORIAL	OTHER
331	2319	STEAMLINER CARPET CLEANER	192303	2006-11-14	100.00	244466	CLEAN CHAIRS	JANITORIAL				JANITORIAL	OTHER
332	3767	ADELPHIA	192304	2006-01-01	46.79	238877	45010098011557	CABLE SERVICES				CABLE SERVICES	OTHER
333	3767	ADELPHIA	192304	2006-01-01	48.79	238877	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
334	3767	ADELPHIA	192304	2006-01-13	53.01	237378	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
335	3767	ADELPHIA	192304	2006-02-01	50.89	237588	45010098011557	CABLE SERVICES				CABLE SERVICES	OTHER
336	3767	ADELPHIA	192304	2006-02-14	53.01	237505	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
337	3767	ADELPHIA	192304	2006-03-01	50.89	238211	45010098011557	CABLE SERVICES				CABLE SERVICES	OTHER
338	3767	ADELPHIA	192304	2006-03-01	50.89	238211	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
339	3767	ADELPHIA	192304	2006-03-17	53.01	238520	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
340	3767	ADELPHIA	192304	2006-04-01	50.89	238779	45010098011557	CABLE SERVICES				CABLE SERVICES	OTHER
341	3767	ADELPHIA	192304	2006-04-01	50.89	238779	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
342	3767	ADELPHIA	192304	2006-04-20	53.01	239187	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
343	3767	ADELPHIA	192304	2006-04-30	53.01	239963	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
344	3767	ADELPHIA	192304	2006-05-01	50.89	239411	45010098011557	CABLE SERVICES				CABLE SERVICES	OTHER
345	3767	ADELPHIA	192304	2006-05-01	50.89	239411	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
346	3767	ADELPHIA	192304	2006-05-01	50.89	240163	45010098011557	CABLE SERVICES				CABLE SERVICES	OTHER
347	3767	ADELPHIA	192304	2006-06-01	50.89	240163	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
348	3767	ADELPHIA	192304	2006-06-14	53.01	240645	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
349	3767	ADELPHIA	192304	2006-07-01	50.89	240902	45010098011557	CABLE SERVICES				CABLE SERVICES	OTHER
350	4432	ADELPHIA	192304	2006-07-01	50.89	240902	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
351	4432	ADELPHIA	192304	2006-07-11	53.01	241217	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
352	3767	ADELPHIA	192304	2006-08-04	50.89	241787	45010098011557	CABLE SERVICES				CABLE SERVICES	OTHER
353	4432	ADELPHIA	192304	2006-08-04	50.89	241787	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
354	4432	ADELPHIA	192304	2006-08-11	54.07	242527	45010098011557	CABLE SERVICES				CABLE SERVICES	OTHER
355	4432	ADELPHIA	192304	2006-09-01	50.89	242527	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
356	4432	ADELPHIA	192304	2006-09-13	53.01	242926	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
357	4432	ADELPHIA	192304	2006-09-13	53.01	242926	45010098011557	CABLE SERVICES				CABLE SERVICES	OTHER
358	3767	ADELPHIA	192304	2006-10-01	50.89	243196	45010098012738	CABLE SERVICES				CABLE SERVICES	OTHER
359	3767	ADELPHIA	192304	2006-10-01	50.89	243196	45010098011557	CABLE SERVICES				CABLE SERVICES	OTHER
360	316	BLUEGRASS REGIONAL MH/MR BOARD	192304	2006-01-30	498.24	237633	OCT-DEC 2005	MEDICAL				MEDICAL	OTHER
361	316	BLUEGRASS REGIONAL MH/MR BOARD	192304	2006-04-18	498.24	239226	JAN-MAR 2006	MEDICAL				MEDICAL	OTHER
362	318	BLUEGRASS REGIONAL MH/MR BOARD	192304	2006-07-21	498.24	241538	APR-JUN 06	MEDICAL				MEDICAL	OTHER
363	318	BLUEGRASS REGIONAL MH/MR BOARD	192304	2006-09-30	498.24	243487	JUL-SEP 06	MEDICAL CLAIMS				MEDICAL CLAIMS	OTHER
364	318	BLUEGRASS REGIONAL MH/MR BOARD	192304	2006-12-31	498.24	245610	OCT-DEC 06	MEDICAL				MEDICAL	OTHER
365	469	CAUDILL JOHNNY	192304	2006-11-22	15.00	244580	201589	FLU SHOT 2006				FLU SHOT 2006	OTHER
366	3810	CHARTER COMMUNICATIONS	192304	2006-02-01	20.84	237161	78611001014017	COMMUNICATIONS SERVICE				COMMUNICATIONS SERVICE	OTHER
367	3810	CHARTER COMMUNICATIONS	192304	2006-02-01	20.84	237764	78611001014017	COMMUNICATIONS SERVICE				COMMUNICATIONS SERVICE	OTHER
368	3810	CHARTER COMMUNICATIONS	192304	2006-02-01	20.84	238340	78611001014017	COMMUNICATIONS SERVICE				COMMUNICATIONS SERVICE	OTHER
369	3810	CHARTER COMMUNICATIONS	192304	2006-03-06	20.84	238930	78611001014017	COMMUNICATIONS SERVICE				COMMUNICATIONS SERVICE	OTHER
370	3810	CHARTER COMMUNICATIONS	192304	2006-04-01	20.84	239502	78611001014017	COMMUNICATIONS SERVICE				COMMUNICATIONS SERVICE	OTHER
371	3810	CHARTER COMMUNICATIONS	192304	2006-05-03	20.84	239728	78611001014017	COMMUNICATIONS SERVICE				COMMUNICATIONS SERVICE	OTHER
372	3810	CHARTER COMMUNICATIONS	192304	2006-06-01	20.84	240429	78611001014017	COMMUNICATIONS SERVICE				COMMUNICATIONS SERVICE	OTHER
373	3810	CHARTER COMMUNICATIONS	192304	2006-07-03	20.84	241082	78611001014017	COMMUNICATIONS SERVICE				COMMUNICATIONS SERVICE	OTHER
374	3810	CHARTER COMMUNICATIONS	192304	2006-08-02	20.84	241986	78611001014017	COMMUNICATIONS SERVICE				COMMUNICATIONS SERVICE	OTHER
375	3810	CHARTER COMMUNICATIONS	192304	2006-09-01	20.84	242699	78611001014017	COMMUNICATIONS SERVICE				COMMUNICATIONS SERVICE	OTHER
376	3217	CURTIS FRANCES	192304	2006-11-16	22.00	244425	201767	FLU SHOT 2006				FLU SHOT 2006	OTHER
377	743	DECKER VIRGINIA	192304	2006-01-26	20.00	237481	20060124	JANITORIAL				JANITORIAL	OTHER
378	3304	EEO ASSOCIATES	192304	2006-11-30	194.40	244878	11905	LINDA POSTLEWAITE				LINDA POSTLEWAITE	OTHER

LINE NO.	VEN #	VENDOR NAME	AC NO	DATE	AMOUNT	CK NUMBER	INV #	INVOICE DESCRIPTION	HRLY RATE	NO HOURS	BUSINESS EXP	BUSINESS EXP DESCRIPTION	TYPE SERVICE
379	3342	EMPLOYEE BENEFIT MANAGEMENT CC	192304	2006-02-17	213.75	238124	0106116-IN	MEDICAL CLAIMS					OTHER
380	3342	EMPLOYEE BENEFIT MANAGEMENT CC	192304	2006-02-24	213.75	238239	0206035-IN	MEDICAL CLAIMS					OTHER
381	3342	EMPLOYEE BENEFIT MANAGEMENT CC	192304	2006-03-21	213.75	238704	0306028-IN	MEDICAL CLAIMS					OTHER
382	3342	EMPLOYEE BENEFIT MANAGEMENT CC	192304	2006-04-13	408.50	238248	0406027-IN	MEDICAL CLAIMS					OTHER
383	3342	EMPLOYEE BENEFIT MANAGEMENT CC	192304	2006-05-16	408.50	239884	0506027-IN	MEDICAL CLAIMS					OTHER
384	3342	EMPLOYEE BENEFIT MANAGEMENT CC	192304	2006-06-20	361.00	240839	0606027-IN	MEDICAL CLAIMS					OTHER
385	3342	EMPLOYEE BENEFIT MANAGEMENT CC	192304	2006-07-18	213.75	241564	0706082-IN	MEDICAL CLAIMS					OTHER
386	3342	EMPLOYEE BENEFIT MANAGEMENT CC	192304	2006-08-15	213.75	242201	0806027-IN	MEDICAL CLAIMS					OTHER
387	3342	EMPLOYEE BENEFIT MANAGEMENT CC	192304	2006-09-21	213.75	243218	0906027-IN	MEDICAL CLAIMS					OTHER
388	3342	EMPLOYEE BENEFIT MANAGEMENT CC	192304	2006-10-13	213.75	243653	1006027-IN	MEDICAL CLAIMS					OTHER
389	3342	EMPLOYEE BENEFIT MANAGEMENT CC	192304	2006-11-14	213.75	244433	1106026-IN	MEDICAL CLAIMS					OTHER
390	3342	EMPLOYEE BENEFIT MANAGEMENT CC	192304	2006-12-01	213.75	245641	1206026-IN	MEDICAL CLAIMS					OTHER
391	4520	HELL, JOHN	192304	2006-04-30	74.00	239581	0428106	MEDICAL					OTHER
392	3224	HALL, JOHN	192304	2006-12-13	414.00	245026	DK-00009	MEDICAL					OTHER
393	0	KEYSPAN	192304	2006-04-18	275.00	239262	BL0512178	GAS SAMPLES VARIOUS PLACES					OTHER
394	4692	NEWWAY COMMUNICATIONS	192304	2006-10-05	20.85	243543	01623866-1	COMMUNICATIONS SERVICE					OTHER
395	4692	NEWWAY COMMUNICATIONS	192304	2006-11-30	41.70	244915	01623866-1	COMMUNICATIONS SERVICE					OTHER
396	4270	PAGING BILLING SERVICES	192304	2006-01-03	160.00	236909	003056	PAGING SERVICE					OTHER
397	4270	PAGING BILLING SERVICES	192304	2006-02-01	195.00	237510	003056	PAGING SERVICE					OTHER
398	4270	PAGING BILLING SERVICES	192304	2006-03-01	213.52	238141	003056	PAGING SERVICE					OTHER
399	4270	PAGING BILLING SERVICES	192304	2006-04-01	208.00	238632	003056	PAGING SERVICE					OTHER
400	4270	PAGING BILLING SERVICES	192304	2006-05-01	208.00	239442	003056	PAGING SERVICE					OTHER
401	4270	PAGING BILLING SERVICES	192304	2006-06-01	208.00	240174	011061	PAGING SERVICES					OTHER
402	4270	PAGING BILLING SERVICES	192304	2006-07-01	208.00	240942	003056	PAGING SERVICE					OTHER
403	4270	PAGING BILLING SERVICES	192304	2006-08-01	208.00	241738	003056	PAGING SERVICE					OTHER
404	4270	PAGING BILLING SERVICES	192304	2006-09-01	208.00	242535	003056	PAGING SERVICE					OTHER
405	4270	PAGING BILLING SERVICES	192304	2006-10-01	208.00	243235	003056	PAGING SERVICE					OTHER
406	4270	PAGING BILLING SERVICES	192304	2006-11-06	208.00	244012	003056	PAGING SERVICE					OTHER
407	4270	PAGING BILLING SERVICES	192304	2006-12-01	208.00	244719	003056	PAGING SERVICE					OTHER
408	0	PRICE VINCE	192304	2006-10-31	22.00	244459	REIMBURSE FLL	FLU SHOT 2006					OTHER
409	0	SELECT LAB SERVICES	192304	2006-11-16	45.00	244462	4347	DRUG SCREEN RE ACCIDENT					OTHER
410	2840	SIDWELL, MARJORIE	192304	2006-09-18	320.00	243117	200020	CONSULTANT					OTHER
411	2840	SIDWELL, MARJORIE	192304	2006-08-29	480.00	243240	200021	CONSULTANT					OTHER
412	2840	SIDWELL, MARJORIE	192304	2006-10-26	320.00	243928	200025	CONSULTANT					OTHER
413	3767	TIME WARNER	192304	2006-10-18	53.01	243696	4501007005846	CABLE SERVICES					OTHER
414	3767	TIME WARNER	192304	2006-11-01	50.89	244013	4501009011557	CABLE SERVICES					OTHER
415	3767	TIME WARNER	192304	2006-11-01	50.89	244013	4501009012738	CABLE SERVICES					OTHER
416	3767	TIME WARNER	192304	2006-11-14	53.01	244471	4501007005846	CABLE SERVICES					OTHER
417	3767	TIME WARNER	192304	2006-12-01	50.89	244775	45010090112738	CABLE SERVICES					OTHER
418	3767	TIME WARNER	192304	2006-12-01	50.89	244775	4501009012738	CABLE SERVICES					OTHER
419	3767	TIME WARNER	192304	2006-12-13	53.01	245087	4501007005846	CABLE SERVICES					OTHER
420	3844	UNITY COMMUNICATIONS INC	192304	2006-01-09	147.13	236999	00002853028	COMMUNICATIONS SERVICE					OTHER
421	3844	UNITY COMMUNICATIONS INC	192304	2006-02-03	125.52	237710	00002864288	COMMUNICATIONS SERVICE					OTHER
422	3844	UNITY COMMUNICATIONS INC	192304	2006-03-09	99.02	238447	00002875805	COMMUNICATIONS SERVICE					OTHER
423	3844	UNITY COMMUNICATIONS INC	192304	2006-04-04	99.02	239021	00002885629	COMMUNICATIONS SERVICE					OTHER
424	3844	UNITY COMMUNICATIONS INC	192304	2006-05-03	99.02	239647	00002895392	COMMUNICATIONS SERVICE					OTHER
425	3844	UNITY COMMUNICATIONS INC	192304	2006-06-08	125.52	240523	00002905367	COMMUNICATIONS SERVICE					OTHER
426	3844	UNITY COMMUNICATIONS INC	192304	2006-07-13	99.02	241336	00002914232	COMMUNICATIONS SERVICE					OTHER
427	3844	UNITY COMMUNICATIONS INC	192304	2006-08-03	99.02	241890	00002923709	COMMUNICATIONS SERVICE					OTHER
428	3844	UNITY COMMUNICATIONS INC	192304	2006-09-06	74.34	242677	00002932512	COMMUNICATIONS SERVICE					OTHER
429	3844	UNITY COMMUNICATIONS INC	192304	2006-10-10	99.43	243473	00002941180	COMMUNICATIONS SERVICE					OTHER
430	3844	UNITY COMMUNICATIONS INC	192304	2006-11-01	152.43	244124	00002948936	COMMUNICATIONS SERVICE					OTHER
431	3844	UNITY COMMUNICATIONS INC	192304	2006-12-05	125.93	244943	00002956684	COMMUNICATIONS SERVICE					OTHER
432	4138	URGENT TREATMENT CLINIC	192304	2006-07-31	226.00	242442	900130135556	MEDICAL					OTHER
433	4138	URGENT TREATMENT CLINIC	192304	2006-07-31	332.00	242442	900130135556	MEDICAL					OTHER
434	4138	URGENT TREATMENT CLINIC	192304	2006-10-31	94.00	244530	900130135556	MEDICAL					OTHER
435	4138	URGENT TREATMENT CLINIC	192304	2006-11-30	375.00	238314	27966	COMPUTER CONSULTANT					OTHER
436	3502	ADVANCED SOLUTIONS INC	192305	2006-02-28	360.00	238784	06232001	COMPUTER CONSULTANT					OTHER
437	137	AUBLE CONSULTING SERVICES	192305	2006-03-25	140.00	241061	06232002	CONSULTANT					OTHER
438	137	AUBLE CONSULTING SERVICES	192305	2006-06-21	140.00	241061	06232002	CONSULTANT					OTHER
439	4314	B B & T BANKCARD CORPORATION	192305	2006-01-26	210.94	237723	1950 DT	AD ON SOFTWARE-HP					OTHER
440	4314	B B & T BANKCARD CORPORATION	192305	2006-01-26	10.59	237723	1950 DT	PRINTER STANTON					OTHER
441	4314	B B & T BANKCARD CORPORATION	192305	2006-06-30	349.59	241051	1950 DT	COMPUTER MAINTENANCE					OTHER
442	4314	B B & T BANKCARD CORPORATION	192305	2006-08-31	37.05	242614	1950 DT	COMPUTER MAINTENANCE					OTHER
443	4314	B B & T BANKCARD CORPORATION	192305	2006-09-28	42.39	243448	1950 DT	COMPUTER MAINTENANCE					OTHER
444	4314	B B & T BANKCARD CORPORATION	192305	2006-10-31	90.06	244130	4889 MW	COMPUTER MAINTENANCE					OTHER
445	4314	B B & T BANKCARD CORPORATION	192305	2006-11-30	28.57	244806	1950 DT	COMPUTER MAINTENANCE					OTHER
446	0	BOX LAKE NETWORKS	192305	2006-03-21	42.50	238795	6776	COMPUTER CONSULTANT					OTHER
447	4689	BOX LAKE NETWORKS INC	192305	2006-08-31	170.00	243068	7466	COMPUTER CONSULTANT					OTHER
448	4689	BOX LAKE NETWORKS INC	192305	2006-09-18	148.75	243204	7532	COMPUTER CONSULTANT					OTHER
449	4689	BOX LAKE NETWORKS INC	192305	2006-09-26	42.50	243361	7577	COMPUTER CONSULTANT					OTHER

LINE NO.	VEN N	VENDOR NAME	AC NO	DATE	AMOUNT	CK NUMBER	INV #	INVOICE DESCRIPTION	HRLY RATE	NO HOURS	BUSINESS EXP	BUSINESS EXP DESCRIPTION	TYPE SERVICE
450	4512	BUSINESS SOLUTIONS GROUP INC.	192305	2006-01-30	300.00	237485	2917	IT CONSULTING					OTHER
451	4512	BUSINESS SOLUTIONS GROUP INC.	192305	2006-02-28	350.00	238294	3014	IT CONSULTING					OTHER
452	4512	BUSINESS SOLUTIONS GROUP INC.	192305	2006-03-25	235.00	238687	3060	IT CONSULTING					OTHER
453	4512	BUSINESS SOLUTIONS GROUP INC.	192305	2006-03-31	225.00	238895	3079	IT CONSULTING					OTHER
454	4512	BUSINESS SOLUTIONS GROUP INC.	192305	2006-04-30	100.00	239555	3146	IT CONSULTING					OTHER
455	4512	BUSINESS SOLUTIONS GROUP INC.	192305	2006-05-13	325.00	239722	3161	IT CONSULTING					OTHER
456	3813	CDW DIRECT LLC	192305	2006-01-31	(610.42)	237638	VW33712	ADOBE ACRBAT STANDARD VERSION					OTHER
457	3813	CDW DIRECT LLC	192305	2006-03-17	312.10	238800	WZ72831	ADOBE ACRBAT STANDARD VERSION					OTHER
458	3813	CDW DIRECT LLC	192305	2006-05-23	(795.98)	240427	ZJ16282	ADOBE ACRBAT STANDARD VERSION					OTHER
459	3813	CDW DIRECT LLC	192305	2006-06-22	466.99	241081	ZX27123	ADOBE ACRBAT STANDARD VERSION					OTHER
460	3764	COGNOS CORPORATION	192305	2006-12-13	266.18	245107	238638	IMPROMPTU SUPPORT THROUGH 11/2					OTHER
461	3803	DATATRADE LLC	192305	2006-10-17	150.00	243805	2006-523	SPOOLVIEW SOFTWARE ESCROW					OTHER
462	4235	EARTHLINK INC.	192305	2006-04-07	23.95	238928	262988223	INTERNET SERVICES					OTHER
463	4235	EARTHLINK INC.	192305	2006-05-11	23.95	239742	267558757	INTERNET SERVICES					OTHER
464	4235	EARTHLINK INC.	192305	2006-08-11	23.95	242001	281787950	INTERNET SERVICES					OTHER
465	4109	EASYLEINK SERVICES CORPORATION	192305	2006-01-31	36.52	237930	076804506802	COMPUTER CONSULTANT					OTHER
466	4109	EASYLEINK SERVICES CORPORATION	192305	2006-02-28	33.60	238549	076804506803	COMPUTER CONSULTANT					OTHER
467	4109	EASYLEINK SERVICES CORPORATION	192305	2006-04-18	31.26	239246	076804506804	COMPUTER CONSULTANT					OTHER
468	4109	EASYLEINK SERVICES CORPORATION	192305	2006-05-22	26.94	240152	076804506805	COMPUTER CONSULTANT					OTHER
469	4109	EASYLEINK SERVICES CORPORATION	192305	2006-06-21	34.14	240637	076804506806	COMPUTER CONSULTANT					OTHER
470	4109	EASYLEINK SERVICES CORPORATION	192305	2006-07-19	29.31	241563	076804506807	COMPUTER CONSULTANT					OTHER
471	4109	EASYLEINK SERVICES CORPORATION	192305	2006-08-16	28.74	242200	076804506808	COMPUTER CONSULTANT					OTHER
472	4109	EASYLEINK SERVICES CORPORATION	192305	2006-09-18	34.02	243087	076804506809	COMPUTER CONSULTANT					OTHER
473	4109	EASYLEINK SERVICES CORPORATION	192305	2006-10-17	28.50	243807	076804506810	COMPUTER CONSULTANT					OTHER
474	4109	EASYLEINK SERVICES CORPORATION	192305	2006-10-31	27.48	244431	076804506811	COMPUTER CONSULTANT					OTHER
475	4109	EASYLEINK SERVICES CORPORATION	192305	2006-11-30	30.36	245014	076804506812	COMPUTER CONSULTANT					OTHER
476	3265	ITRON INC	192305	2006-11-27	(35.57)	244642	308317	SOFTWARE MAINTENANCE					OTHER
477	0	LACERTE SOFTWARE	192305	2006-09-25	224.72	243102	5392653	SOFTWARE LICENSE FEE					OTHER
478	4453	MAILWATCH	192305	2006-01-01	135.00	237037	0816570	E-MAIL SECURITY SYSTEM					OTHER
479	4453	MAILWATCH	192305	2006-02-03	135.00	237942	0811126	E-MAIL SECURITY SYSTEM					OTHER
480	4453	MAILWATCH	192305	2006-03-03	135.00	238560	0811673	E-MAIL SECURITY SYSTEM					OTHER
481	4453	MAILWATCH	192305	2006-04-01	135.00	238967	0812227	E-MAIL SECURITY SYSTEM					OTHER
482	4453	MAILWATCH	192305	2006-05-01	135.00	240002	0812758	E-MAIL SECURITY SYSTEM					OTHER
483	4453	MAILWATCH	192305	2006-06-01	135.00	240685	0813292	E-MAIL SECURITY SYSTEM					OTHER
484	4453	MAILWATCH	192305	2006-07-31	270.00	241862	08-1000208	E-MAIL SECURITY SYSTEM					OTHER
485	4453	MAILWATCH	192305	2006-09-01	135.00	242966	0814881	E-MAIL SECURITY SYSTEM					OTHER
486	4453	MAILWATCH	192305	2006-10-01	135.00	243672	0815533	E-MAIL SECURITY SYSTEM					OTHER
487	4453	MAILWATCH	192305	2006-11-01	135.00	244446	0815472	E-MAIL SECURITY SYSTEM					OTHER
488	4453	MAILWATCH	192305	2006-12-01	135.00	245054	0816133	E-MAIL SECURITY SYSTEM					OTHER
489	4655	TCG AMERICA LLC	192305	2006-06-30	250.00	241142	2502	IT CONSULTING					OTHER
490	4655	TCG AMERICA LLC	192305	2006-07-24	150.00	240954	2438	IT CONSULTING					OTHER
491	4655	TCG AMERICA LLC	192305	2006-07-31	475.00	241653	2519	IT CONSULTING					OTHER
492	4655	TCG AMERICA LLC	192305	2006-08-23	350.00	241880	2543	IT CONSULTING					OTHER
493	4655	TCG AMERICA LLC	192305	2006-08-25	425.00	242437	2576	IT CONSULTING					OTHER
494	4655	TCG AMERICA LLC	192305	2006-08-31	350.00	243056	2609	IT CONSULTING					OTHER
495	4655	TCG AMERICA LLC	192305	2006-08-31	300.00	242767	2586	IT CONSULTING					OTHER
496	4655	TCG AMERICA LLC	192305	2006-10-31	225.00	244117	2669	IT CONSULTING					OTHER
497	4655	TCG AMERICA LLC	192305	2006-12-12	225.00	245085	2721	IT CONSULTING					OTHER
498	4655	TCG AMERICA LLC	192305	2006-12-22	200.00	245119	2744	IT CONSULTING					OTHER
499	4655	TCG AMERICA LLC	192305	2006-12-31	100.00	245412	2752	IT CONSULTING					OTHER
500		TOTAL			657,984.12								



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

61. Refer to the response to the Staff's First Request, Item 28.
- a. Describe the nature and purpose of the consulting services provided by H. D. Peet, Eunice Yarber, and Juanita Hensley.
  - b. Concerning the compensation study by Mercer Human Resource Consultants, does Delta agree this is a non-recurring expenditure and that it should not be included for rate-making purposes? Explain the response.
  - c. Describe the nature and purpose of the employee relations and benefits provided by Stoll Keenon and Ogden.
  - d. Describe the nature and purpose of the "TGP General Matters" provided by Miller Balis & O'Neil, P.C.
  - e. Describe the nature and purpose of cable services provided by Adelphia.
  - f. Describe the nature and purpose of the information technology services provided by TCG America LLC.

**RESPONSE:**

- a) H. D. Peet provides general consulting services to Delta's Chairman, President & CEO as required. Mr. Peet is Delta's founder and is retired from the position of Chairman of the Board, President & Chief Executive Officer.  
  
Eunice Yarber provides accounting services to Delta's accounting department as required. Ms. Yarber is retired from Delta's accounting department.  
  
Juanita Hensley provides consulting services in the human resources area. She is retired from Delta's human resources department.
- b) It is not planned to recur next year, but it should be allowed for ratemaking purposes as it is a valid business expense incurred to meet the Commission's directives in its order in Case No. 2004-00067.
- c) Stoll Keenon & Ogden is a legal firm that provides legal services to Delta in employee related areas of human resources.

**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

- d) Miller Balis & O'Neil, P.C. is a legal firm that provides legal services representing Delta and other Tennessee Gas Pipeline ("TGP") customers in Federal Energy Regulatory Commission matters relating to Delta's service from TGP.
- e) The nature and purpose of cable services is so our gas control department can monitor the weather on a daily basis.
- f) TCG American provides Delta services to the information technology department to assist in day to day operational services on servers and programs.

Sponsoring Witness:

Glenn R. Jennings



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

62. Refer to the response to the Staff's First Request, Item 31(f). Provide a schedule detailing the overhead, salaries, and bonuses allocated or assigned to Delta's three subsidiaries during the test year. Explain in detail how any allocations or assignments were determined.

**RESPONSE:**

Consistent with previous test years, Delta computes an administrative fee that it charges to the subsidiaries. The purpose of the fee is to reimburse Delta for the costs incurred in rendering management services provided to the subsidiaries. Delta adjusts the monthly fee every six months based on actual history. The December 2006 fee was \$6,300 per month. See the attached schedule for the computation of the fee.

In addition to the management fee, Delta charged 100% of the bonus payments made to employees and directors during the test year to the subsidiaries.

Sponsoring Witness:

John B. Brown



Delta Natural Gas Co., Inc.  
Allocation of Joint Costs to Subsidiaries

## Joint Cost Summary

Admin payroll	2,418,668	
Admin payroll taxes	179,934	(carved out of 408.03)
Admin benefits	755,851	(carved out of 926's)
Admin transportation	85,100	
Operations transportation	639,762	
Admin operating expenses (921's)	577,026	
Admin expenses (930's)	549,836	
Admin maintenance expenses (932's)	192,767	
Outside services	631,390	(included only Winchester janitorial in 1.923.03)
Insurance	272,204	Directors' and officers
	12,180	EPLI
	3,045	Fiduciary
	3,147	Crime
	21,256	Employee benefits
Winchester depreciation	333,494	
	6,675,660	
Expenses transferred to capital	(2,388,484)	
	4,287,176	
% Admin time spent on subs	1.750%	
Applicable to Subs	75,025.58	
Say	75,000	
Amount to book monthly	6,250	
Per sub (Resources, Delgasco, Enpro)	2,100	



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

63. Refer to the response to the Staff's First Request, Item 39(a). In determining Delta's revenue requirements and proposed increase in revenues, were the expenses shown in this response included or excluded from the test-year income statement?
- a. If included, explain why these expenses were included in the determination of the revenue requirements and proposed revenue increase for Delta's regulated operations.
  - b. If excluded, indicate where in the record Delta has shown these expenses were excluded from test-year expenses.

RESPONSE:

- a. N/A
- b. The first digit of our account number dictates the company. Delta's company number is 1, so our system prevents these expenses from being included on Delta's income statement since they all have first digits other than 1.

Sponsoring Witness:

John B. Brown



**DELTA NATURAL GAS COMPANY, INC.  
CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST  
DATED 6/07/07**

64. Refer to the response to the Staff's First Request, Item 43. Delta has a tariff titled "Rider for Gas Technology Institute Research and Development." Explain in detail why Delta responded to Item 43 that there was no research and development activity during the test year. In addition, describe Delta's involvement with the Gas Technology Institute.

**RESPONSE:**

We answered the question strictly relative to the Pro Forma test year. Delta incurred no expenses during the test year, or the 3 preceding calendar years, for research and development activities and therefore there is nothing requested in this case.

The \$12,157 we paid to the Gas Technology Institute during the test year was collected from customers under the tariff referred to in this question. Our involvement with the Gas Technology Institute has been to discuss how they would utilize the research funds we remitted to them.

Sponsoring Witness:

Glenn R. Jennings



**DELTA NATURAL GAS COMPANY, INC.**  
**CASE NO. 2007-00089**

**SECOND PSC DATA REQUEST**  
**DATED 6/07/07**

65. Refer to the response to the Staff's First Request, Item 46. Provide a detailed description of the employee education benefit and the employee recreation and social benefit. Include in the discussion the reason(s) why the expense for the benefit should be included for rate-making purposes.

**RESPONSE:**

Employees can attend classes to further their education and Delta assists them with this where it improves their skills and develops them further as employees. This provides Delta with a better educated and trained workforce with which to serve its customers.

Employee recreation and social is for employee meetings. Company operations are discussed and employees can interact with Delta management and employees. This provides for a better informed workforce with which to serve our customers.

Sponsoring Witness:

Glenn R. Jennings