Columbia Gas® of Kentucky
A NiSource Company

P.O. Box 14241
2001 Mercer Road
Lexington, KY 40512-4241

May 1, 2006

Ms. Beth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, KY 40602

RECEIVED
MAY 0 1 2006
PUBLIC SERVICE COMMISSION

Re: Columbia Gas of Kentucky, Inc.
Gas Cost Adjustment Case No. 2006 - 00179

Dear Ms. O'Donnell:

Pursuant to the Commission's Order dated January 30, 2001 in Administrative Case No. 384, Columbia Gas of Kentucky, Inc. ("Columbia") hereby encloses, for filing with the Commission, an original and six (6) copies of data submitted pursuant to the requirements of the Gas Cost Adjustment Provision contained in Columbia's tariff for its June quarterly Gas Cost Adjustment ("GCA").

Columbia proposes to decrease its current rates to tariff sales customers by \$0.7604 per Mcf effective with its June 2006 billing cycle on May 31, 2006. The decrease is composed of a decrease of \$0.7953 per Mcf in the Average Commodity Cost of Gas, an increase of \$0.0005 per Mcf in the Average Demand Cost of Gas, a decrease of \$0.0114 per Mcf in the Refund Adjustment, and the initial Gas Cost Incentive Adjustment of \$0.0230 per Mcf.

Pursuant to the Commission's Order dated March 29, 2005, the Gas Cost Incentive Adjustment is to be calculated annually based on the reporting period of April through October of the preceding year. This filing includes the first calculation of the incentive adjustment. Future revisions will be calculated annually in Columbia's March quarterly GCA.

Please feel free to contact me at 859-288-0242 if there are any questions.

Sincerely,

Judy Cooper

Judy M. Cooper
Director, Regulatory Policy

Enclosures

BEFORE THE
PUBLIC SERVICE COMMISSION
OF KENTUCKY

COLUMBIA GAS OF KENTUCKY, INC.

CASE 2006-00179

GAS COST ADJUSTMENT AND REVISED RATES OF
COLUMBIA GAS OF KENTUCKY, INC. PROPOSED TO BECOME
EFFECTIVE JUNE 2006 BILLINGS

Columbia Gas of Kentucky, Inc.
Comparison of Current and Proposed GCAs

Line No.		March-06 CURRENT	June-06 PROPOSED	DIFFERENCE
1	Commodity Cost of Gas	$10.5575	$9.7622	($0.7953)
2	Demand Cost of Gas	$1.2141	$1.2146	$0.0005
3	Total: Expected Gas Cost (EGC)	$11.7716	$10.9768	($0.7948)
4	SAS Refund Adjustment	($0.0001)	($0.0001)	$0.0000
5	Balancing Adjustment	($0.0026)	($0.0026)	$0.0000
6	Supplier Refund Adjustment	($0.0246)	($0.0132)	$0.0114
7	Actual Cost Adjustment	($0.7033)	($0.7033)	$0.0000
8	Gas Cost Incentive Adjustment	$0.0000	$0.0230	$0.0230
9	Cost of Gas to Tariff Customers (GCA)	$11.0410	$10.2806	($0.7604)
10	Transportation TOP Refund Adjustment	$0.0000	$0.0000	$0.0000
11	Banking and Balancing Service	$0.0205	$0.0205	$0.0000
12	Rate Schedule FI and GSO			
13	Customer Demand Charge	$6.5610	$6.5490	($0.0120)

Columbia Gas of Kentucky, Inc.
Gas Cost Adjustment Clause
Gas Cost Recovery Rate
June - Aug 2006

Line No.	Description		Amount	Expires
1	Expected Gas Cost (EGC)	Schedule No. 1	$10.9768	
2	Actual Cost Adjustment (ACA)	Schedule No. 2	($0.7033)	8-31-06
3	SAS Refund Adjustment (RA)	Schedule No. 5	($0.0001)	8-31-06
4	Supplier Refund Adjustment (RA)	Schedule No. 4	($0.0007)	05-31-07
		Schedule No. 4 Case No. 2006-	($0.0124)	02-28-07
		Schedule No. 4 Case No. 2005-00318	($0.0001)	11-30-06
		Total Refunds	($0.0132)	
5	Balancing Adjustment (BA)	Schedule No. 3	($0.0026)	8-31-06
6	Gas Cost Incentive Adjustment	Schedule No. 6	$0.0230	5-31-07
7	Gas Cost Adjustment			
8	June - Aug 2006		$10.2806	
9	Expected Demand Cost (EDC) per Mcf			
10	(Applicable to Rate Schedule IS/SS and GSO)	Schedule No. 1, Sheet 4	$6.5490	

DATE FILED: May 1, 2006 **BY: J. M. Cooper**

Columbia Gas of Kentucky, Inc.
Expected Gas Cost for Sales Customers
June - Aug 2006

Schedule No. 1
Sheet 1

Line No.	Description		Reference	Volume A/ Mcf (1)	Dth. (2)	Rate Per Mcf (3)	Per Dth (4)	Cost (5)
	Storage Supply							
	Includes storage activity for sales customers only							
	Commodity Charge							
1	Withdrawal				0		$0.0153	$0
2	Injection				2,254,000		$0.0153	$34,486
3	Withdrawals: gas cost includes pipeline fuel and commodity charges				0		$0.00	$0
	Total							
4	Volume	= 3			0			
5	Cost	sum(1:3)						$34,486
6	Summary	4 or 5			0			$34,486
	Flowing Supply							
	Excludes volumes injected into or withdrawn from storage.							
	Net of pipeline retention volumes and cost. Add unit retention cost on line 17							
7	Non-Appalachian		Sch.1, Sht. 5, Ln. 4		5,247,000			$45,644,998
8	Appalachian Supplies		Sch.1, Sht. 6, Ln. 4		61,000			$517,000
9	Less Fuel Retention By Interstate Pipelines		Sch. 1,Sheet 7, Lines 21, 22		(109,000)			($1,072,312)
10	Total	7 + 8 + 9			5,199,000			$45,089,686
	Total Supply							
11	At City-Gate		Line 6 + 10		5,199,000			$45,124,172
	Lost and Unaccounted For							
12	Factor				-0.9%			
13	Volume		Line 11 * 12		(46,791)			
14	At Customer Meter		Line 11 + 13		5,152,209			
15	**Sales Volume**		Line 14	4,881,297	5,152,209			
	Unit Costs $/MCF							
	Commodity Cost							
16	Excluding Cost of Pipeline Retention		Line 11 / Line 15			$9.2443		
17	Annualized Unit Cost of Retention		Sch. 1,Sheet 7, Line 24			$0.5179		
18	Including Cost of Pipeline Retention		Line 16 + 17			$9.7622		
19	Demand Cost		Sch.1, Sht. 2, Line 9			$1.2146		
20	Total Expected Gas Cost (EGC)		Line 18 + 19			$10.9768		

A/ BTU Factor = 1.0555 Dth/MCF

Columbia Gas of Kentucky, Inc.
GCA Unit Demand Cost
June - Aug 2006

Schedule No. 1
Sheet 2

Line No.	Description		Reference		
1	Expected Demand Cost: Annual June 2006 - May 2007		Sch. No.1, Sheet 3, Ln. 41	$20,020,561	
2	Less Rate Schedule IS/SS and GSO Customer Demand Charge Recovery		Sch. No.1, Sheet 4, Ln. 10	-$449,363	
3	Less Storage Service Recovery from Delivery Service *Customers*			-$157,815	
4	Net Demand Cost Applicable	1 + 2 + 3		$19,413,382	
	Projected Annual Demand: Sales + Choice June 2006 - May 2007				
	At city-gate				
	In Dth			17,023,000	Dth
	Heat content			1.0555	Dth/MCF
5	In MCF			16,127,901	MCF
	Lost and Unaccounted - For				
6	Factor			0.9%	
7	Volume	5 * 6		145,151	MCF
8	At Customer Meter	5 - 7		15,982,750	MCF
9	Unit Demand Cost (7 / 10)	To Sheet 1, line 19		$1.2146	per MCF

Columbia Gas of Kentucky, Inc.
Annual Demand Cost of Interstate Pipeline Capacity
June 2006 - May 2007

Schedule No. 1
Sheet 3

Line No.	Description		Dth	Monthly Rate $/Dth	# Months	Expected Annual Demand Cost
	Columbia Gas Transmission Corporation					
	Firm Storage Service (FSS)					
1	FSS Max Daily Storage Quantity (MDSQ)		220,880	$1.5000	12	$3,975,840
2	FSS Seasonal Contract Quantity (SCQ)		11,264,911	$0.0288	12	$3,893,153
	Storage Service Transportation (SST)					
3	Summer	June - Sept. 06, Apr. - May 07	110,440	$4.1850	6	$2,773,148
4	Winter	Oct. 06 - Mar. 07	220,880	$4.1850	6	$5,546,297
5	Firm Transportation Service (FTS)		20,014	$5.9410	12	$1,426,838
6	Subtotal	sum(1:5)				$17,615,277
	Columbia Gulf Transmission Company					
11	FTS - 1 (Mainline)		28,991	$3.1450	12	$1,094,120
	Tennessee Gas					
21	Firm Transportation		20,506	$4.6238	12	$1,137,788
	Central Kentucky Transmission					
31	Firm Transportation	June 06- May 07	28,000	$0.5160	12	$173,376
41	**Total.** *Used on Sheet 2, line 1*					$20,020,561

Columbia Gas of Kentucky, Inc.
Gas Cost Adjustment Clause
Expected Demand Costs Recovered Annually From Rate Schedule IS/SS and GSO Customers
June - Aug 2006

Line No.	Description		Capacity Daily Dth (1)	# Months (2)	Annualized Dth (3) = (1) x (2)	Units	Annual Cost (3)
1	Expected Demand Costs (Per Sheet 3)						$20,020,561
	City-Gate Capacity:						
	Columbia Gas Transmission						
2	Firm Storage Service - FSS		220,880	12	2,650,560		
3	Firm Transportation Service - FTS		20,014	12	240,168		
4	Central Kentucky Transportation	June 06 - May 07	28,000	12	336,000		
5	Total	2 + 3 + 4			3,226,728	Dth	
6	*Divided by Average BTU Factor*				1.0555	Dth/MCF	
7	Total Capacity - Annualized	Line 5/ Line 6			3,057,061	Mcf	
8	Monthly Unit Expected Demand Cost (EDC) of Daily Capacity Applicable to Rate Schedules IS/SS and GSO Line 1 / Line 7				*$6.5490*	*/Mcf*	
9	Firm Volumes of IS/SS and GSO Customers		5,718	12	68,616	Mcf	
10	Expected Demand Charges to be Recovered Annually from Rate Schedule IS/SS and GSO Customers	Line 8 * Line 9			to Sheet 2, line 2		$449,363

Columbia Gas of Kentucky, Inc.
Non-Appalachian Supply: Volume and Cost
June - Aug 2006

Cost includes transportation commodity cost and retention by the interstate pipelines, but excludes pipeline demand costs.
The volumes and costs shown are for sales customers only.

		Total Flowing Supply Including Gas Injected Into Storage				Net Flowing Supply for Current Consumption	
Line No.	Month	Volume A/ Dth (1)	Cost (2)	Unit Cost $/Dth (3) = (2) / (1)	Net Storage Injection Dth (4)	Volume Dth (5) = (1) + (4)	Cost (6) = (3) x (5)
1	Jun-06	267,000	$2,189,000	$8.20	56,000	323,000	$2,648,116
2	Jul-06	1,370,000	$11,815,000	$8.62	1,107,000	2,477,000	$21,361,865
3	Aug-06	1,356,000	$11,989,000	$8.84	1,091,000	2,447,000	$21,635,017
4	Total 1+2+3	2,993,000	$25,993,000	$8.68	2,254,000	5,247,000	$45,644,998

A/ Gross, before retention.

Columbia Gas of Kentucky, Inc.
Appalachian Supply: Volume and Cost
June - Aug 2006

Schedule No. 1
Sheet 6

Line No.	Month		Dth (2)	Cost (3)
1	Jun-06		21,000	$173,000
2	Jul-06		20,000	$171,000
3	Aug-06		20,000	$173,000
4	Total	1 + 2 + 3	61,000	$517,000

Columbia Gas of Kentucky, Inc.
Annualized Unit Charge for Gas Retained by Upstream Pipelines
June - Aug 2006

Schedule No. 1
Sheet 7

Retention costs are incurred proportionally to the volumes purchased, *but recovery of the costs is allocated to quarter by volume consumed.*

			Units	June - Aug 2006	Sept - Nov 06	Dec 06 - Feb 07	Mar - May 2007	Annual June 2006 - May 2007
	Gas purchased by CKY for the remaining sales customers							
1	Volume		Dth	3,054,000	2,555,000	1,950,000	3,361,000	10,920,000
2	Commodity Cost Including Transportation			$26,510,000	$23,436,000	$23,632,000	$33,850,000	$107,428,000
3	Unit cost		$/Dth					$9.8377
	Consumption by the remaining sales customers							
11	At city gate		Dth	691,000	1,968,000	5,907,000	2,541,000	11,107,000
12	Lost and unaccounted for portion			0.90%	0.90%	0.90%	0.90%	
	At customer meters							
13	In Dth	(100% - 12) * 11	Dth	684,781	1,950,288	5,853,837	2,518,131	11,007,037
14	Heat content		Dth/MCF	1.0555	1.0555	1.0555	1.0555	
15	In MCF	13 / 14	MCF	648,774	1,847,739	5,546,032	2,385,723	10,428,268
16	*Portion of annual*	line 15, quarterly / annual		6.2%	17.7%	53.2%	22.9%	100.0%
	Gas retained by upstream pipelines							
21	Volume		Dth	109,000	121,000	200,000	119,000	549,000
	Cost			To Sheet 1, line 9				
22	Quarterly. Deduct from Sheet 1	3 * 21		$1,072,312	$1,190,365	$1,967,546	$1,170,690	$5,400,913
23	*Allocated to quarters by consumption*			$336,007	$956,964	$2,872,350	$1,235,592	$5,400,913
				To Sheet 1, line 17				
24	Annualized unit charge	23 / 15	$/MCF	$0.5179	$0.5179	$0.5179	$0.5179	$0.5179

COLUMBIA GAS OF KENTUCKY, INC.

Schedule No. 1
Sheet 8

DETERMINATION OF THE BANKING AND BALANCING CHARGE
FOR THE PERIOD BEGINNING JUNE 2006

Line No.	Description	Dth	Detail	Amount For Transportation Customers
1	Total Storage Capacity. Sheet 3, line 4	11,264,911		
2	Net Transportation Volume	8,118,967		
3	Contract Tolerance Level @ 5%	405,948		
4	Percent of Annual Storage Applicable			
5	to Transportation Customers		3.60%	
6	Seasonal Contract Quantity (SCQ)			
7	Rate		$0.0288	
8	SCQ Charge - Annualized		$3,893,153	
9	Amount Applicable To Transportation Customers			**$140,154**
10	FSS Injection and Withdrawal Charge			
11	Rate		0.0306	
12	Total Cost		$344,706	
13	Amount Applicable To Transportation Customers			**$12,409**
14	SST Commodity Charge			
15	Rate		0.0157	
16	Total Cost		$145,894	
17	Amount Applicable To Transportation Customers			**$5,252**
18	Total Cost Applicable To Transportation Customers			**$157,815**
19	Total Transportation Volume - Mcf			17,883,000
20	Flex and Special Contract Transportation Volume - Mcf			(10,190,942)
21	Net Transportation Volume - Mcf	line 19 + line 20		7,692,058
22	*Banking and Balancing Rate - Mcf.*	*Line 18 / line 21. To line 11 of the GCA Comparison*		$0.0205

REFUND ADJUSTMENT

COLUMBIA GAS OF KENTUCKY, INC.

SUPPLIER REFUND ADJUSTMENT

Line No.	Description	Amount
1	Supplier Refund from Columbia Gas Transmission (Jan. 2006)	$11,055
2	To Be Passed Back to Customers	
3	Interest on Refund Balances	$371
4	REFUND INCLUDING INTEREST	$11,426
5	Divided By:	
6	Projected Sales for the Twelve Months Ended May 31, 2007	15,982,750
7	**SUPPLIER REFUND TO EXPIRE May 31, 2007**	**($0.0007)**
8	**TOTAL SUPPLIER REFUND TO EXPIRE May 31, 2007**	**($0.0007)**

CKY RATE REFUND INTEREST CALCULATION
SELECTED INTEREST RATES
COMMERCIAL PAPER - 3-MONTH

February 20, 2006

RATE	MONTH	DAYS	x	DAILY RATE	x	Columbia Gas Trans.	=	INTEREST
4.37	JANUARY 2006	31		0.000092		11,054.72		31.53
4.55	FEBRUARY 2006	28		0.000092		11,054.72		28.48
4.76	MARCH 2006	31		0.000092		11,054.72		31.53
2.97	APRIL 2005	30		0.000092		11,054.72		30.51
3.09	MAY 2005	31		0.000092		11,054.72		31.53
3.27	JUNE 2005	30		0.000092		11,054.72		30.51
3.47	JULY 2005	31		0.000092		11,054.72		31.53
3.64	AUGUST 2005	31		0.000092		11,054.72		31.53
3.72	SEPTEMBER 2005	30		0.000092		11,054.72		30.51
4.01	OCTOBER 2005	31		0.000092		11,054.72		31.53
4.23	NOVEMBER 2005	30		0.000092		11,054.72		30.51
4.23	DECEMBER 2005	31		0.000092		11,054.72		31.53
46.31	TOTAL					TOTAL		371.23
0.000092	DAILY RATE							

Columbia Gas
Transmission.

A NiSource Company

Thomas D. Stone
Manager
Rates & Tariffs

12801 Fair Lakes Parkway
Fairfax VA 22033

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March 20, 2006

Federal Energy Regulatory Commission
Room 1A, East
888 First Street, N. E.
Washington, D.C. 20246

Attention: Ms. Magalie Roman Salas, Secretary

Re: Refunds under the April 17, 1995 Settlement in Docket No. GP94-02, et al.

Dear Ms. Salas:

Pursuant to Section 154.501(e) of the Federal Regulatory Commission's ("Commission") regulations, Columbia Gas Transmission Corporation ("Columbia") herewith submits an original and five paper copies of its refund report in the above referenced docket.

Statement of Nature, Reasons and Basis for Filing

On February 20, 2006 Columbia made refunds as a result of a settlement filed on April 17, 1995 in Docket GP94-02, et al. ("Settlement"). The Settlement was approved by the Commission on June 15, 1995 (Columbia Gas Transmission Corp., 71 FERC ¶ 61,337 (1995)).

The refunds made on February 20, 2006, as billing credits or checks, represent deferred tax refunds received from Trailblazer Pipeline Company (Trailblazer) of $253,319.00 and from Overthrust Pipeline Company (Overthrust) of $58,532.07 plus interest of $2,483.66 and $594.04, respectively using the FERC interest rate in accordance with the Code of Federal Regulations, Subpart F, Section 154.501 (d). These refunds were made pursuant to Article VIII, Section E of the Settlement. Per Article VIII, Section E, "Columbia shall pay to the parties (provided they are Supporting Parties), using the allocation percentages shown on Appendix G, Schedule 5 [of the Settlement], all refunds received from Wyoming Interstate Company, Ltd., Trailblazer Pipeline Company, Ozark Gas Transmission Company, Overthrust Pipeline Company and any other pipeline relating to the flowback of excess deferred income taxes collected by such upstream pipelines for the period prior to the Stipulation Filing Date with FERC Interest...."

Materials Submitted Herewith

In accordance with Section 154.501(e)(6) of the Commission's regulations, the following material is submitted herewith:

(1) Workpapers showing how the refund and interest were calculated; and

(2) A Form of Notice for this filing suitable for publication in the Federal Register, as required by Section 154.209 of the Commission's regulations, and a diskette copy of such Notice of Filing labeled "TF032006.NTA".

Waiver

Columbia respectfully requests that the Commission grant any waivers that it may deem necessary to accept this filing.

Posting and Certification of Service

Pursuant to Section 154.601(f) of the Commission's regulations, a copy of this refund report is being sent by Columbia by first-class mail, postage prepaid, to each of Columbia's customers receiving any refund and state commissions whose jurisdiction includes the location of any recipient of a refund that have made a standing request for such full reports.

Pursuant to Section 154.501(g) of the Commission's regulations, recipients of refunds and state commissions that have not made a standing request for such full report shall receive an abbreviated report.

This report is also available for public inspection during regular business hours in a convenient form and place at Columbia's offices at 12801 Fair Lakes Parkway, Fairfax, Virginia; and 10G Street, N.E., Suite 580 Washington, D.C.

Subscription

Pursuant to Section 154.4(b) of the Commission's regulations, the undersigned certifies that: (1) he knows the contents of the filing; (2) the paper copies of the filing contain the same information as that contained on the electronic media; (3) the contents are true to the best of his knowledge and belief; and (4) that he possesses the full power and authority to sign the filing.

Service on Columbia

It is respectfully requested that all Commission orders and correspondence as well as pleadings and correspondence from other persons concerning this filing be served upon the following:

*Thomas D. Stone, Manager, Rates and Tariffs
Columbia Gas Transmission Corporation
12801 Fair Lakes Parkway
Fairfax, Virginia 22033
Phone: (703) 227-3262 Fax: (713) 227-3308
Email: tdstone@nisource.com

*Kurt L. Krieger, Assistant General Counsel
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*Sharon Theodore, Manager, Regulatory Affairs
Columbia Gas Transmission Corporation
10 G Street, N.E., Suite 580
Washington, D.C. 20002
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Email: sjroyka@nisource.com

* Persons designated to receive service in accordance with Rule 203 of the Commission's Rules of Practice and Procedures, 18 C.F.R § 385.203 (2006)

Respectfully submitted,

Thomas D. Stone

Thomas D. Stone
Manager, Rates and Tariffs

Enclosures

COLUMBIA GAS TRANSMISSION CORPORATION
ALLOCATION OF EXCESS DEFERRED INCOME TAXES 1/
REFUNDED ON JANUARY 2006 INVOICES

LINE NO.	CUST. NO.	CUSTOMER NAME	ALLOCATION FACTOR/ 2	TRAILBLAZER REFUND	OVERTHRUST REFUND	TOTAL REFUND
1	008715	ALLIEDSIGNAL, INC. (000022) / HONEYWELL INTERNATIONAL, INC.	0.418139%	1,069.61	247.23	1,316.84
2	002277	ARLINGTON NATURAL GAS COMPANY	0.062786%	160.61	37.12	197.73
3	000074	BALTIMORE GAS & ELECTRIC	4.493301%	11,493.98	2,656.71	14,150.69
4	002278	BELFRY GAS COMPANY	0.009520%	24.35	5.63	29.98
5	000928	BETHLEHEM STEEL CORPORATION	0.418140%	1,069.61	247.23	1,316.84
6	001471	BLACKSVILLE OIL & GAS	0.007253%	18.55	4.29	22.84
7	000109	BLUEFIELD GAS COMPANY	0.162843%	416.56	96.28	512.84
8	000633	CAMERON GAS COMPANY (000145) / MOUNTAINEER GAS COMPANY	0.025839%	66.10	15.28	81.38
9	000165	CENTAL HUSDON GAS & ELECTRIC	0.209578%	536.11	123.92	660.03
10	000187	CG&E / ULH&P	5.022987%	12,848.93	2,969.90	15,818.83
11	000192	CITY OF AUGUSTA	0.033092%	84.65	19.57	104.22
12	002279	CITY OF BROOKSVILLE	0.008386%	21.45	4.96	26.41
13	002280	CITY OF CARLISLE	0.052132%	133.36	30.82	164.18
14	000193	CITY OF CHARLOTTESVILLE	0.334866%	856.60	197.99	1,054.59
15	002282	CITY OF FLEMINGSBURG	0.043065%	110.16	25.46	135.62
16	000197	CITY OF LANCASTER	0.459188%	1,174.62	271.50	1,446.12
17	010756	CITY OF NORTH MIDDLETOWN (002288) / DELTA - NORTH MIDDLETOW	0.007027%	17.98	4.15	22.13
18	000198	CITY OF RICHMOND	1.333340%	3,410.72	788.35	4,199.07
19	001472	CLAYSVILLE NATURAL GAS COMPANY	0.051451%	131.61	30.42	162.03
20	000208	COLUMBIA GAS OF KENTUCKY	3.510229%	8,979.26	2,075.46	11,054.72
21	000209	COLUMBIA GAS OF MARYLAND	0.810917%	2,074.35	479.46	2,553.81
22	000214	COLUMBIA GAS OF OHIO	32.900233%	84,159.65	19,452.67	103,612.32
23	000221	COLUMBIA GAS OF PENNSYLVANIA	9.820267%	25,120.50	5,806.34	30,926.84
24	008238	COLUMBIA GAS OF VIRGINIA	3.152522%	8,064.24	1,863.96	9,928.20
25	000261	CORNING NATURAL GAS	0.028321%	72.45	16.75	89.20
26	010316	DAYTON POWER & LIGHT (000278) / PROLIANCE ENERGY	4.426995%	11,324.37	2,617.51	13,941.88
27	001860	DELMARVA POWER & LIGHT COMPANY	0.239190%	611.85	141.42	753.27
28	000284	DELTA NATURAL GAS COMPANY	0.273577%	699.82	161.76	861.58
29	008233	EASTERN NATURAL GAS COMPANY	0.035041%	89.64	20.72	110.36
30	000314	EASTERN SHORE NATURAL GAS	0.260360%	666.01	153.94	819.95
31	000322	ELAM UTILITY COMNPANY	0.021759%	55.66	12.87	68.53
32	009872	ELIZABETHTOWN GAS (000323) / NUI	0.191352%	489.48	113.14	602.62
33	010781	GAS TRANSPORT (002416) / FIRST ENERGY	0.002392%	6.12	1.41	7.53
34	003574	INTERSTATE UTILITIES (000483) / GASCO DISTRIBUTION	0.019039%	48.70	11.26	59.96
35	010757	KANE LIGHT AND HEAT (000510) / GASCO - KANE	0.022666%	57.98	13.40	71.38
36	002283	KENTUCKY OHIO GAS COMPANY / NATURAL ENERGY UTILITY CORPOI	0.004533%	11.60	2.68	14.28
37	002284	LAKESIDE GAS COMPANY	0.004760%	12.18	2.81	14.99
38	000633	MOUNTAINEER GAS COMPANY	6.162242%	15,763.18	3,643.49	19,406.67
39	002285	DELTA MT. OLIVET NATURAL GAS COMPANY	0.011332%	28.99	6.70	35.69
40	002286	MURPHY GAS	0.004079%	10.43	2.41	12.84
41	004266	NASHVILLE GAS COMPANY	0.358785%	917.78	212.14	1,129.92
42	004789	NATIONAL FUEL GAS DISTRIBUTION	0.035520%	90.86	21.00	111.86
43	000646	NATIONAL FUEL GAS SUPPLY	0.000239%	0.61	0.14	0.75
44	002287	NATIONAL GAS & OIL COOPERATIVE	0.086811%	222.06	51.33	273.39
45	007901	NEW ENGLAND POWER (005781) / US GENERATING COMPANY	0.418139%	1,069.61	247.23	1,316.84
46	002407	NEW JERSEY NATURAL GAS COMPANY	0.233145%	596.39	137.85	734.24
47	000666	NEW YORK STATE ELECTRIC & GAS (I & II)	1.535768%	3,928.54	908.04	4,836.58
48	002409	NORTH CAROLINA NATURAL GAS	0.581118%	1,486.52	343.59	1,830.11
49	004906	NORTHEAST OHIO GAS MARKETING	0.002267%	5.80	1.34	7.14
50	002436	OHIO CUMBERLAND GAS COMPANY	0.045332%	115.96	26.80	142.76
51	000700	ORANGE & ROCKLAND UTILITIES	1.233776%	3,156.03	729.48	3,885.51
52	004098	ORWELL NATURAL GAS COMPANY	0.045332%	115.96	26.80	142.76
53	000723	PPL GAS UTILITIES CORPORATION	0.405190%	1,036.49	239.57	1,276.06
54	000724	PG ENERGY INC	0.634221%	1,622.35	374.99	1,997.34
55	000726	PEOPLES NATURAL GAS COMPANY	0.069204%	177.03	40.92	217.95
56	001871	PIEDMONT NATURAL GAS COMPANY	1.345394%	3,441.55	795.48	4,237.03
57	001063	PIKE NATURAL GAS COMPANY	0.111289%	284.68	65.80	350.48
58	004351	PROVIDENCE GAS COMPANY	0.239190%	611.85	141.42	753.27
59	000778	RICHMOND UTILITIES BOARD	0.226659%	579.80	134.01	713.81
60	000784	ROANOKE GAS COMPANY	0.684083%	1,749.90	404.47	2,154.37
61	000821	SHELDON GAS COMPANY	0.043292%	110.74	25.60	136.34
62	000838	SOUTH JERSEY GAS COMPANY	1.074550%	2,748.73	635.34	3,384.07
63	000870	SUBURBAN NATURAL GAS COMPANY	0.101656%	260.04	60.11	320.15
64	002291	SWICKARD GAS COMPANY	0.023799%	60.88	14.07	74.95
65	002292	T.W. PHILLIPS GAS &OIL	0.187462%	479.53	110.84	590.37
66	000942	UGI UTILITIES	2.037635%	5,212.32	1,204.77	6,417.09

COLUMBIA GAS TRANSMISSION CORPORATION
ALLOCATION OF EXCESS DEFERRED INCOME TAXES 1/
REFUNDED ON JANUARY 2006 INVOICES

LINE NO.	CUST. NO.	CUSTOMER NAME	ALLOCATION FACTOR/ 2	TRAILBLAZER REFUND	OVERTHRUST REFUND	TOTAL REFUND
67	002294	VANCEBURG ELECTRIC	0.027879%	71.32	16.48	87.80
68	002295	VERONA NATURAL GAS COMPANY	0.018133%	46.38	10.72	57.10
69	002298	VILLAGE OF WILLIAMSPORT	0.014053%	35.95	8.31	44.26
70	006525	PARAMOUNT NATURAL GAS CO (002293) / M&B GAS SERVICES	0.007027%	17.98	4.15	22.13
71	000996	VIRGINIA NATURAL GAS	1.482977%	3,793.49	876.83	4,670.32
72	001006	WASHINGTON GAS	10.049805%	25,707.67	5,942.06	31,649.73
73	001062	WATERVILLE GAS COMPANY	0.056664%	144.95	33.50	178.45
74	001010	WATERVILLE GAS & OIL COMPANY	0.113329%	289.90	67.01	356.91
75	002400	WEST MILLGROVE GAS COMPANY	0.001814%	4.64	1.07	5.71
76	002412	WEST OHIO GAS (001020) / EAST OHIO GAS	1.393325%	3,564.16	823.82	4,387.98
77	002296	WESTERN LEWIS-RECTORVILLE	0.015866%	40.59	9.38	49.97
78	002299	ZEBULON GAS ASSOCIATION	0.004533%	11.60	2.68	14.28
79		TOTAL	100.000000%	255,802.66	59,126.11	314,928.77

1/ ALLOCATED PURSUANT TO ARTICLE VIII, SECTION E, OF COLUMBIA'S "CUSTOMER SETTLEMENT" IN DOCKET NO. GP94-02, ET AL.

2/ SEE APPENDIX G, SCHEDULE 5 OF COLUMBIA'S "CUSTOMER SETTLEMENT" IN DOCKET NO. GP94-02, ET AL.

COLUMBIA GAS TRANSMISSION CORPORATION
COMPUTATION OF INTEREST DUE

BUSINESS DATE	PRINCIPAL AMOUNT	FROM DATE	TO DATE	NO DAYS	INTEREST RATE	DAILY RATE	INTEREST AMOUNT	COMPOUND BASE
Trailblazer Refund								
December 2005	253,319.00	12/29/2005	12/31/2005	3	6.23%	0.000170685	129.71	253,448.71
		1/1/2006	2/20/2006	50	6.78%	0.000185753	2,353.95	255,802.66
Trailblazer Total	253,319.00						2,483.66	255,802.66
Overthrust Refund								
December 2005	58,532.07	12/27/2005	12/31/2005	5	6.23%	0.000170685	49.95	58,582.02
		1/1/2006	2/20/2006	50	6.78%	0.000185753	544.09	59,126.11
Overthrust Total	58,532.07						594.04	59,126.11
Total Refunds	311,851.07						3,077.70	314,928.77

ATTACHMENT B

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Columbia Gas Transmission Corporation) Docket No. GP94-02, et al.

NOTICE OF REFUND REPORT

Take notice that on March 20, 2006, Columbia Gas Transmission Corporation ("Columbia") endered for filing with the Federal Energy Regulatory Commission ("Commission") its Refund Report nade to comply with the April 17, 1995 Settlement ("Settlement") in Docket No. GP94-02, et al. as approved by the Commission on June 15, 1995 (Columbia Gas Transmission Corp., 71 FERC ¶ 61,337 (1995)).

On February 20, 2006 Columbia made refunds, as billing credits and with checks, in the amount of $314,928.77. The refunds represent deferred tax refunds received from Trailblazer Pipeline Company and Overthrust Pipeline Company. These refunds were made pursuant to Article VIII, Section E of the Settlement using the allocation percentages shown on Appendix G, Schedule 5 of the Settlement. The refunds include interest at the FERC rate, in accordance with the Code of Federal Regulations, Subpart F, Section 154.501 (d).

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed in accordance with the provisions of Section 154.210 of the Commission's regulations (18 CFR 154.210). Anyone filing an intervention or protest must serve a copy of that document on the Applicant. Anyone filing an intervention or protest on or before the intervention or protest date need not serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Magalie R. Salas
Secretary

GAS COST INCENTIVE ADJUSTMENT

COLUMBIA GAS OF KENTUCKY, INC.

GAS COST INCENTIVE ADJUSTMENT

Line No.	Description	Amount
1	Amount to be recovered For period April - October 2005	$368,262
2	Divided By: Projected Sales for the Twelve Months Ended May 31, 2007	15,982,750
3	Gas Cost Incentive Adjustment per Mcf Effective June 2007 - May 2007	$ 0.0230

PIPELINE COMPANY TARIFF SHEETS

Currently Effective Rates
Applicable to Rate Schedule FTS and NTS
Rate Per Dth

		Base Tariff Rate 1/	Transportation Cost Rate Adjustment Current	Transportation Cost Rate Adjustment Surcharge	Electric Power Costs Adjustment Current	Electric Power Costs Adjustment Surcharge	Annual Charge Adjustment 2/	Total Effective Rate	Daily Rate
Rate Schedule FTS									
Reservataion Charge 3/	$	5.575	0.354	-0.017	0.029	0.000	-	5.941	0.195
Commodity									
Maximum	¢	1.04	0.25	0.00	0.26	0.01	0.18	1.74	1.74
Minimum	¢	1.04	0.25	0.00	0.26	0.01	0.18	1.74	1.74
Overrun	¢	19.37	1.41	-0.06	0.36	0.01	0.18	21.27	21.27
Rate Schedule NTS									
Reservation Charge 3/	$	7.084	0.354	-0.017	0.029	0.000	-	7.450	0.245
Commodity									
Maximum	¢	1.04	0.25	0.00	0.26	0.01	0.18	1.74	1.74
Minimum	¢	1.04	0.25	0.00	0.26	0.01	0.18	1.74	1.74
Overrun	¢	24.33	1.41	-0.06	0.36	0.01	0.18	26.23	26.23

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively. For rates by function, see Sheet No. 30A.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ Minimum reservation charge is $0.00.

Currently Effective Rates
Applicable to Rate Schedule SST and GTS
Rate Per Dth

		Base Tariff Rate 1/	Transportation Cost Rate Adjustment Current	Transportation Cost Rate Adjustment Surcharge	Electric Power Costs Adjustment Current	Electric Power Costs Adjustment Surcharge	Annual Charge Adjustment 2/	Total Effective Rate	Daily Rate
Rate Schedule SST									
Reservation Charge 3/	$	5.405	0.354	-0.017	0.029	0.000	-	5.771	0.190
Commodity									
Maximum	¢	1.02	0.25	0.00	0.26	0.01	0.18	1.72	1.72
Minimum	¢	1.02	0.25	0.00	0.26	0.01	0.18	1.72	1.72
Overrun	¢	18.79	1.41	-0.06	0.36	0.01	0.18	20.69	20.69
Rate Schedule GTS									
Commodity									
Maximum	¢	74.23	2.58	-0.11	0.45	0.01	0.18	77.34	77.34
Minimum	¢	3.08	0.25	-0.11	0.26	0.01	0.18	3.67	3.67
MFCC	¢	71.15	2.33	0.00	0.19	0.00	-	73.67	73.67

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively. For rates by function, see Sheet No. 30A.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ Minimum reservation charge is $0.00.

Currently Effective Rates
Applicable to Rate Schedule FSS, ISS, and SIT
Rate Per Dth

		Base Tariff Rate 1/	Transportation Cost Rate Adjustment Current	Transportation Cost Rate Adjustment Surcharge	Electric Power Costs Adjustment Current	Electric Power Costs Adjustment Surcharge	Annual Charge Adjustment 2/	Total Effective Rate	Daily Rate
Rate Schedule FSS									
Reservation Charge	$	1.500	-	-	-	-	-	1.500	0.049
Capacity	¢	2.88	-	-	-	-	-	2.88	2.88
Injection	¢	1.53	-	-	-	-	-	1.53	1.53
Withdrawal	¢	1.53	-	-	-	-	-	1.53	1.53
Overrun	¢	10.87	-	-	-	-	-	10.87	10.87
Rate Schedule ISS									
Commodity									
Maximum	¢	5.92	-	-	-	-	-	5.92	5.92
Minimum	¢	0.00	-	-	-	-	-	0.00	0.00
Injection	¢	1.53	-	-	-	-	-	1.53	1.53
Withdrawal	¢	1.53	-	-	-	-	-	1.53	1.53
Rate Schedule SIT									
Commodity									
Maximum	¢	4.11	-	-	-	-	-	4.11	4.11
Minimum	¢	1.53	-	-	-	-	-	1.53	1.53

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.

Currently Effective Rates
Applicable to Rate Schedule FTS-1
Rates per Dth

	Base Rate (1) $	Annual Charge Adjustment (2) $ 1/	Subtotal (3) $	Total Effective Rate (4) $	Daily Rate (5) $	Company Use and Unaccounted For (6) %
Rate Schedule FTS-1						
Rayne, LA To Points North						
Reservation Charge 2/	3.1450	-	3.1450	3.1450	0.1034	-
Commodity						
Maximum	0.0170	0.0018	0.0188	0.0188	0.0188	2.265
Minimum	0.0170	0.0018	0.0188	0.0188	0.0188	2.265
Overrun	0.1204	0.0018	0.1222	0.1222	0.1222	2.265

1/ Pursuant to Section 154.402 of the Commission's Regulations. Rate applies to all Gas Delivered and is non-cumulative, i.e., when transportation involves more than one zone, rate will be applied only one time.

2/ The Minimum Rate under Reservation Charge is zero (0).

DETAIL SUPPORTING

DEMAND/COMMODITY SPLIT

COLUMBIA GAS OF KENTUCKY
CASE NO. 2006 - Effective June 2006 Billing Cycle

CALCULATION OF DEMAND/COMMODITY SPLIT OF GAS COST ADJUSTMENT FOR TARIFFS

	$/MCF	
Demand Component of Gas Cost Adjustment		
Demand Cost of Gas (Schedule No. 1, Sheet 1, Line 19)	$1.2146	
Demand ACA (Schedule No. 2, Sheet 1, Line 23)	0.1526	
Refund Adjustment (Schedule No. 4)	-0.0132	
SAS Refund Adjustment (Schedule No. 5)	-0.0001	
Total Demand Rate per Mcf	$1.3539	<--- to Att. E, line 21
Commodity Component of Gas Cost Adjustment		
Commodity Cost of Gas (Schedule No. 1, Sheet 1, Line 18)	$9.7622	
Commodity ACA (Schedule No. 2, Sheet 1, Line 28)	-$0.8559	
Balancing Adjustment (Schedule No. 3, Sheet 1, Line 21)	-$0.0026	
Gas Cost Incentive Adjustment (Schedule No. 6)	$0.0230	
Total Commodity Rate per Mcf	$8.9267	
CHECK:	$1.3539	
	$8.9267	
COST OF GAS TO TARIFF CUSTOMERS (GCA)	$10.2806	

Calculation of Rate Schedule SVGTS - Actual Gas Cost Adjustment

Commodity ACA (Schedule No. 2, Sheet 1, Line 28)	-$0.8559	
Balancing Adjustment (Schedule No. 3, Sheet 1, Line 21)	-$0.0026	
Gas Cost Incentive Adjustment (Schedule No. 6)	$0.0230	
Total Commodity Rate per Mcf	-$0.8355	

Columbia Gas of Kentucky, Inc.
CKY Choice Program
100% Load Factor Rate of Assigned FTS Capacity
Balancing Charge
June - Aug 2006

Line No.	Description		Contract Volume Dth Sheet 3	Retention	Monthly demand charges $/Dth Sheet 3	# months A/	Assignment proportions lines 4, 5	Adjustment for retention on downstream pipe, if any	Annual costs $/Dth	Annual costs $/MCF
			(1)	(2)	(3)	(4)	(5)	(6) = 1 / (100%-col2)	(7) = 3 * 4 * 5 * 6	
	City gate capacity assigned to Choice marketers									
	Contract									
1	CKT FTS/SST		28,000	1.000%						
2	TCO FTS		20,014	2.007%						
3	Total		48,014							
	Assignment Proportions									
4	CKT FTS/SST	1 / 3	58.32%							
5	TCO FTS	2 / 3	41.68%							
	Annual demand cost of capacity assigned to choice marketers									
11	CKT FTS				$0.5160	12	0.5832	1.0000	$3.6109	
12	TCO SST @ CKT FTS rate				$1.5300	0	0.5832	1.0000	$0.0000	
13	TCO FTS				$5.9410	12	0.4168	1.0000	$29.7171	
14	Gulf FTS-1, upstream to CKT FTS				$3.1450	12	0.5832	1.0101	$22.2309	
15	TGP FTS-A, upstream to TCO FTS				$4.6238	12	0.4168	1.0205	$23.6021	
16	Total Demand Cost of Assigned FTS, per unit								$79.1611	$83.5150
17	100% Load Factor Rate (16 / 365 days)									$0.2288
	Balancing charge, paid by Choice marketers									
21	Demand Cost Recovery Factor in GCA, per Mcf per CKY Tariff Sheet No. 5									$1.3539
22	Less credit for cost of assigned capacity									($0.2288)
23	Plus storage commodity costs incurred by CKY for the Choice marketer									$0.1198
24	Balancing Charge, per Mcf sum(21:23)									$1.2449

A/ TCO SST and CKT, together total 12 months.

PROPOSED TARIFF SHEETS

CURRENTLY EFFECTIVE BILLING RATES

	Base Rate Charge $	Gas Cost Adjustment[1/] Demand $	Gas Cost Adjustment[1/] Commodity $	Total Billing Rate $	
RATE SCHEDULE GSR					
First 1 Mcf or less per billing period	6.95	1.3539	8.9267	17.2306	R
Over 1 Mcf per billing period	1.8715	1.3539	8.9267	12.1521	R
RATE SCHEDULE GSO					
Commercial or Industrial					
First 1 Mcf or less per billing period	18.88	1.3539	8.9267	29.1606	R
Next 49 Mcf per billing period	1.8715	1.3539	8.9267	12.1521	R
Next 350 Mcf per billing period	1.8153	1.3539	8.9267	12.0959	R
Next 600 Mcf per billing period	1.7296	1.3539	8.9267	12.0102	R
Over 1000 Mcf per billing period	1.5802	1.3539	8.9267	11.8608	R
Delivery Service					
Administrative Charge	55.90			55.90	
Standby Service Demand Charge					
Demand Charge times Daily Firm Vol. (Mcf) in Cust. Serv. Agrmt.		6.5490		6.5490	R
Delivery Rate Per Mcf					
First 400 Mcf per billing period	1.8153			1.8153	
Next 600 Mcf per billing period	1.7296			1.7296	
All Over 1000 Mcf per billing period	1.5802			1.5802	
Former IN8 Rate Per Mcf	1.0575			1.0575	
Banking and Balancing Service		0.0205		0.0205	

(continued on following sheet)

1/ The Gas Cost Adjustment, as shown, is an adjustment per Mcf determined in accordance with the "Gas Cost Adjustment Clause" as set forth on Sheets 48 through 51 of this Tariff. The Gas Cost Adjustment applicable to a customer who is receiving service under Rate Schedule GS, IN6, or IUS and received service under Rate Schedule SVGTS shall be $10.9768 per Mcf only for those months of the prior twelve months during which they were served under Rate Schedule SVGTS R

(R) Reduction

DATE OF ISSUE: May 1, 2006

DATE EFFECTIVE: June 2006 Billing Cycle (May 31, 2006)

ISSUED BY: Joseph W. Kelly, President

CURRENTLY EFFECTIVE BILLING RATES

(Continued)

	Base Rate Charge $	Gas Cost Adjustment[1/] Demand $	Gas Cost Adjustment[1/] Commodity $	Total Billing Rate $	
RATE SCHEDULE GPR[3/]					
First 1 Mcf or less per billing period	6.95	N/A	N/A	N/A	
Over 1 Mcf per billing period	1.8715	N/A	N/A	N/A	
RATE SCHEDULE GPO[3/]					
Commercial or Industrial					
First 1 Mcf or less per billing period	18.88	N/A	N/A	N/A	
Next 49 Mcf per billing period	1.8715	N/A	N/A	N/A	
Next 350 Mcf per billing period	1.8153	N/A	N/A	N/A	
Next 600 Mcf per billing period	1.7296	N/A	N/A	N/A	
Over 1000 Mcf per billing period	1.5802	N/A	N/A	N/A	
RATE SCHEDULE IS					
Customer Charge per billing period	116.55			116.55	
First 30,000 Mcf	0.5467		8.9267 [2/]	9.4734	R
Over 30,000 Mcf	0.2905		8.9267 [2/]	9.2172	R
Standby Service Demand Charge					
Demand Charge times Daily Firm Volume (Mcf) in Customer Service Agreement		6.5490		6.5490	R
Delivery Service1					
Administrative Charge	55.90			55.90	
First 30,000 Mcf	0.5467				
Over 30,000 Mcf	0.2905			0.2905	
Banking and Balancing Service	0.0205			0.0205	

(continued on following sheet)

1/ The Gas Cost Adjustment, as shown, is an adjustment per Mcf determined in accordance with the "Gas Cost Adjustment Clause" as set forth on Sheets 48 through 51 of this Tariff.
2/ IS Customers may be subject to the Demand Gas Cost, under the conditions set forth on Sheets 14 and 15 of this tariff.
3/ Currently, there are no customers on this rate schedule.

(R) – Reduction

DATE OF ISSUE: May 1, 2006 **DATE EFFECTIVE:** June 2006 Billing Cycle (May 31, 2006)

ISSUED BY: Joseph W. Kelly President

CURRENTLY EFFECTIVE BILLING RATES

(Continued)

	Base Rate Charge $	Gas Cost Adjustment[1/] Demand $	Gas Cost Adjustment[1/] Commodity $	Total Billing Rate $	
RATE SCHEDULE IUS					
For All Volumes Delivered Per Mcf	0.3038	1.3539	8.9267	10.5844	R
Delivery Service					
Administrative Charge	55.90			55.90	
Delivery Rate Per Mcf	0.3038	1.3539		1.6577	I
Banking and Balancing Service		0.0205		0.0205	
MAINLINE DELIVERY SERVICE					
Administrative Charge	55.90			55.90	
Delivery Rate Per Mcf	0.0858			0.0858	
Banking and Balancing Service		0.0205		0.0205	

1/ The Gas Cost Adjustment, as shown, is an adjustment per Mcf determined in accordance with the "Gas Cost Adjustment Clause" as set forth on Sheets 48 through 51 of this Tariff.

R – Reduction I- Increase

DATE OF ISSUE: May 1, 2006

DATE EFFECTIVE: June 2006 Billing Cycle
May 31, 2006

ISSUED BY: Joseph W. Kelly President

CURRENTLY EFFECTIVE BILLING RATES

RATE SCHEDULE SVGTS	Delivery Charge per Mcf	
General Service Residential		
First 1 Mcf or less per billing period	$ 6.95 (Minimum Bill)	
Over 1 Mcf per billing period	1.8715	
General Service Other		
First 1 Mcf or less per billing period	$18.88 (Minimum Bill)	
Next 49 Mcf per billing period	1.8715	
Next 350 Mcf per billing period	1.8153	
Next 600 Mcf per billing period	1.7296	
Over 1000 Mcf per billing period	1.5802	
Intrastate Utility Service		
For all volumes per billing period	$ 0.038	
Actual Gas Cost Adjustment		
For all volumes per billing period	$ (0.8355)	I
Rate Schedule SVAS		
Balancing Charge – per Mcf	$ 1.2449	I

(I) Increase

DATE OF ISSUE: May 1, 2006

DATE EFFECTIVE: June 2006 Billing Cycle (May 31, 2006)

ISSUED BY: Joseph W. Kelly, President