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PUBLIC SERVICE COMMISSION

Columbia Gas of Kentucky
A NiSource Company

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

July 27, 2010

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, KY 40602

Re: Columbia Gas of Kentucky, Inc.
Gas Cost Adjustment Case No. 2010 - 00307

Dear Mr. Derouen:

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 September quarterly Gas Cost Adjustment ("GCA").

Columbia proposes to increase its current rates to tariff sales customers by $2.5385 per Mcf effective with its September 2010 billing cycle on August 27, 2010. The increase is composed of an increase of $1.0856 per Mcf in the Average Commodity Cost of Gas, an increase of $0.0011 per Mcf in the Average Demand Cost of Gas, a decrease of ($1.2554) per Mcf in the Balancing Adjustment, a decrease of $0.0001 per Mcf in the Refund Adjustment and an increase of 2.7071 per Mcf in the Actual Adjustment. Please feel free to contact me at 859-288-0242 or jmcoop@nisource.com 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 2010 -

GAS COST ADJUSTMENT AND REVISED RATES OF
COLUMBIA GAS OF KENTUCKY, INC. PROPOSED TO BECOME
EFFECTIVE SEPTEMBER 2010 BILLINGS

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

Line No.		June 2010 CURRENT	September-10 PROPOSED	DIFFERENCE
1	Commodity Cost of Gas	$4.7585	$5.8441	$1.0856
2	Demand Cost of Gas	$1.3310	$1.3321	$0.0011
3	Total: Expected Gas Cost (EGC)	$6.0895	$7.1762	$1.0867
4	SAS Refund Adjustment	($0.0002)	($0.0002)	$0.0000
5	Balancing Adjustment	$1.2853	$0.0299	($1.2554)
6	Supplier Refund Adjustment	($0.0082)	($0.0081)	$0.0001
7	Actual Cost Adjustment	($2.9537)	($0.2466)	$2.7071
8	Gas Cost Incentive Adjustment	$0.0042	$0.0042	$0.0000
9	Cost of Gas to Tariff Customers (GCA)	$4.4169	$6.9554	$2.5385
10	Transportation TOP Refund Adjustment	$0.0000	$0.0000	$0.0000
11	Banking and Balancing Service	$0.0208	$0.0207	($0.0001)
12	Rate Schedule FI and GSO			
13	Customer Demand Charge	$6.5273	$6.5273	($0.0000)

Columbia Gas of Kentucky, Inc.
Gas Cost Adjustment Clause
Gas Cost Recovery Rate
Sept - Nov 10

Line No.	Description			Amount	Expires
1	Expected Gas Cost (EGC)	Schedule No. 1		$7.1762	
2	Actual Cost Adjustment (ACA)	Schedule No. 2		($0.2466)	8-31-11
3	SAS Refund Adjustment (RA)	Schedule No. 5		($0.0002)	8-31-11
4	Supplier Refund Adjustment (RA)	Schedule No. 4			
			Case No. 2010-00186	($0.0019)	05-31-11
			Case No. 2010-00041	($0.0062)	02-28-11
		Total Refunds		($0.0081)	
5	Balancing Adjustment (BA)	Schedule No. 3		$0.0299	2-28-11
6	Gas Cost Incentive Adjustment	Schedule No. 6		$0.0042	2-28-11
7	Gas Cost Adjustment				
8	Sept - Nov 10			$6.9554	
9	Expected Demand Cost (EDC) per Mcf				
10	(Applicable to Rate Schedule IS/SS and GSO)	Schedule No. 1, Sheet 4		$6.5273	

DATE FILED: July 27, 2010 **BY: J. M. Cooper**

Columbia Gas of Kentucky, Inc.
Expected Gas Cost for Sales Customers
Sept - Nov 10

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				(1,137,000)		$0.0153	$17,396
2	Injection				1,410,000		$0.0153	$21,573
3	Withdrawals: gas cost includes pipeline fuel and commodity charges				1,131,000		$5.3761	$6,080,378
	Total							
4	Volume	= 3			1,131,000			
5	Cost	sum(1:3)						$6,119,348
6	Summary	4 or 5			1,131,000			$6,119,348
	Flowing Supply							
	Excludes volumes injected into or withdrawn from storage.							
	Net of pipeline retention volumes and cost. Add unit retention cost on line 18							
7	Non-Appalachian		Sch.1, Sht. 5, Ln. 4		889,000			$4,311,650
8	Appalachian Supplies		Sch.1, Sht. 6, Ln. 4		91,000			$431,000
9	Less Fuel Retention By Interstate Pipelines		Sch. 1,Sheet 7, Lines 21, 22		(116,000)			($609,575)
10	Total	7 + 8 + 9			864,000			$4,133,075
	Total Supply							
11	At City-Gate		Line 6 + 10		1,995,000			$10,252,422
	Lost and Unaccounted For							
12	Factor				-0.9%			
13	Volume		Line 11 * 12		(17,955)			
14	At Customer Meter		Line 11 + 13	1,884,875	1,977,045			
15	Less: Right-of-Way Contract Volume			651				
16	**Sales Volume**		Line 14-15	1,884,223				
	Unit Costs $/MCF							
	Commodity Cost							
17	Excluding Cost of Pipeline Retention		Line 11 / Line 16			$5.4412		
18	Annualized Unit Cost of Retention		Sch. 1,Sheet 7, Line 24			$0.3216		
19	Including Cost of Pipeline Retention		Line 17 + 18			$5.7628		
20	Uncollectible Ratio		CN 2009-00141			0.01410552		
21	Gas Cost Uncollectible Charge		Line 19 * Line 20			$0.0813		
22	Total Commodity Cost		line 19 + line 21			$5.8441		
23	Demand Cost		Sch.1, Sht. 2, Line 10			$1.3321		
24	Total Expected Gas Cost (EGC)		Line 22 + 23			$7.1762		

A/ BTU Factor = 1.0489 Dth/MCF

Columbia Gas of Kentucky, Inc.
GCA Unit Demand Cost
Sept - Nov 10

Schedule No. 1
Sheet 2

Line No.	Description		Reference		
1	Expected Demand Cost: Annual Sept 2010 - Aug 2011		Sch. No.1, Sheet 3, Ln. 41	$20,079,812	
2	Less Rate Schedule IS/SS and GSO Customer Demand Charge Recovery		Sch. No.1, Sheet 4, Ln. 10	-$92,818	
3	Less Storage Service Recovery from Delivery Service Customers			-$197,983	
4	Net Demand Cost Applicable	1 + 2 + 3		$19,789,012	
	Projected Annual Demand: Sales + Choice				
	At city-gate				
	In Dth			15,728,000	Dth
	Heat content			1.0489	Dth/MCF
5	In MCF			14,994,756	MCF
	Lost and Unaccounted - For				
6	Factor			0.9%	
7	Volume	5 * 6		134,953	MCF
8	Right of way Volumes			4,542	
9	At Customer Meter	5 - 7- 8		14,855,261	MCF
10	Unit Demand Cost (4/ 9)	To Sheet 1, line 23		$1.3321	per MCF

Columbia Gas of Kentucky, Inc.
Annual Demand Cost of Interstate Pipeline Capacity
Sept 2010 - Aug 2011

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	$1.5060	12	$3,991,743
2	FSS Seasonal Contract Quantity (SCQ)		11,264,911	$0.0289	12	$3,906,671
	Storage Service Transportation (SST)					
3	Summer		110,440	$4.1850	6	$2,773,148
4	Winter		220,880	$4.1850	6	$5,546,297
5	Firm Transportation Service (FTS)		20,014	$6.0750	12	$1,459,021
6	Subtotal	sum(1:5)				$17,676,880
	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		28,000	$0.5090	12	$171,024
41	**Total.** Used on Sheet 2, line 1					$20,079,812

Columbia Gas of Kentucky, Inc. Schedule No. 1
Gas Cost Adjustment Clause Sheet 4
Expected Demand Costs Recovered Annually From Rate Schedule IS/SS and GSO Customers
Sept 2010 - Aug 2011

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)						$20,079,812
	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		28,000	12	336,000		
5	Total	2 + 3 + 4			3,226,728	Dth	
6	Divided by Average BTU Factor				1.0489	Dth/MCF	
7	Total Capacity - Annualized	Line 5/ Line 6			3,076,297	Mcf	
8	Monthly Unit Expected Demand Cost (EDC) of Daily Capacity Applicable to Rate Schedules IS/SS and GSO Line 1 / Line 7				$6.5273	/Mcf	
9	Firm Volumes of IS/SS and GSO Customers		1,185	12	14,220	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		$92,818

Columbia Gas of Kentucky, Inc. Schedule No. 1
Non-Appalachian Supply: Volume and Cost Sheet 5
Sept - Nov 10

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	Sep-10	1,441,000	$6,680,000		(1,147,000)	294,000	
2	Oct-10	852,000	$3,896,000		(257,000)	595,000	
3	Nov-10	0	$550,000		0	0	
4	Total 1+2+3	2,293,000	$11,126,000	$4.85	(1,404,000)	889,000	$4,311,650

A/ Gross, before retention.

Columbia Gas of Kentucky, Inc.
Appalachian Supply: Volume and Cost
Sept - Nov 10

Schedule No. 1
Sheet 6

Line No.	Month		Dth (2)	Cost (3)
1	Sep-10		19,000	$87,000
2	Oct-10		26,000	$120,000
3	Nov-10		46,000	$224,000
4	Total	1 + 2 + 3	91,000	$431,000

Columbia Gas of Kentucky, Inc. Schedule No. 1

Annualized Unit Charge for Gas Retained by Upstream Pipelines Sheet 7

Sept - Nov 10

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

			Units	Sept - Nov 10	Dec 10 - Feb 11	Mar - May 11	June - Aug 11	Annual Sept 2010 - Aug 2011
	Gas purchased by CKY for the remaining sales customers							
1	Volume		Dth	2,384,000	1,819,000	3,370,000	4,425,000	11,998,000
2	Commodity Cost Including Transportation			$11,557,000	$11,093,000	$17,581,000	$22,818,000	$63,049,000
3	Unit cost		$/Dth					$5.2550
	Consumption by the remaining sales customers							
11	At city gate		Dth	1,995,000	6,174,000	2,554,000	675,000	11,398,000
12	Lost and unaccounted for portion			0.90%	0.90%	0.90%	0.90%	
	At customer meters							
13	In Dth	(100% - 12) * 11	Dth	1,977,045	6,118,434	2,531,014	668,925	11,295,418
14	Heat content		Dth/MCF	1.0489	1.0489	1.0489	1.0489	
15	In MCF	13 / 14	MCF	1,884,875	5,833,191	2,413,017	637,740	10,768,823
16	Portion of annual	line 15, quarterly / annual		17.5%	54.2%	22.4%	5.9%	100.0%
	Gas retained by upstream pipelines							
21	Volume		Dth	116,000	193,000	162,000	188,000	659,000
	Cost			To Sheet 1, line 9				
22	Quarterly. Deduct from Sheet 1	3 * 21		$609,575	$1,014,207	$851,303	$987,932	$3,463,018
23	Allocated to quarters by consumption			$606,135	$1,875,827	$775,974	$205,083	$3,463,018
				To Sheet 1, line 18				
24	Annualized unit charge	23 / 15	$/MCF	$0.3216	$0.3216	$0.3216	$0.3216	$0.3216

COLUMBIA GAS OF KENTUCKY, INC.

Schedule No. 1
Sheet 8

DETERMINATION OF THE BANKING AND BALANCING CHARGE FOR THE PERIOD BEGINNING SEPTEMBER 2010

Line No.	Description	Dth	Detail	Amount For Transportation Customers
1	Total Storage Capacity. Sheet 3, line 2	11,264,911		
2	Net Transportation Volume	10,012,879		
3	Contract Tolerance Level @ 5%	500,644		
4	Percent of Annual Storage Applicable			
5	to Transportation Customers		4.44%	
6	Seasonal Contract Quantity (SCQ)			
7	Rate		$0.0289	
8	SCQ Charge - Annualized		$3,906,671	
9	Amount Applicable To Transportation Customers			**$173,456**
10	FSS Injection and Withdrawal Charge			
11	Rate		0.0306	
12	Total Cost		$344,706	
13	Amount Applicable To Transportation Customers			**$15,305**
14	SST Commodity Charge			
15	Rate		0.0243	
16	Projected Annual Storage Withdrawal, Dth		8,547,000	
17	Total Cost		$207,692	
18	Amount Applicable To Transportation Customers			**$9,222**
19	Total Cost Applicable To Transportation Customers			**$197,983**
20	Total Transportation Volume - Mcf			18,658,484
21	Flex and Special Contract Transportation Volume - Mcf			(9,112,408)
22	Net Transportation Volume - Mcf	line 20 + line 21		9,546,076
23	Banking and Balancing Rate - Mcf.	Line 19 / line 22. To line 11 of the GCA Comparison		**$0.0207**

DETAIL SUPPORTING

DEMAND/COMMODITY SPLIT

Columbia Gas of Kentucky, Inc.
CKY Choice Program
100% Load Factor Rate of Assigned FTS Capacity
Balancing Charge
Sept - Nov 10

Line No.	Description		Contract Volume Dth Sheet 3 (1)	Retention (2)	Monthly demand charges $/Dth Sheet 3 (3)	# months A/ (4)	Assignment proportions lines 4, 5 (5)	Adjustment for retention on downstream pipe, if any (6) = 1 / (100%-col2)	Annual costs $/Dth (7) = 3 * 4 * 5 * 6	Annual costs $/MCF
	City gate capacity assigned to Choice marketers									
1	Contract									
2	CKT FTS/SST		28,000	0.553%						
3	TCO FTS		20,014	2.129%						
4	Total		48,014							
5										
6	Assignment Proportions									
7	CKT FTS/SST	1 / 3	58.32%							
8	TCO FTS	2 / 3	41.68%							
9										
10										
	Annual demand cost of capacity assigned to choice marketers									
11	CKT FTS				$0.5090	12	0.5832	1.0000	$3.5620	
12	TCO FTS				$6.0750	12	0.4168	1.0000	$30.3874	
13	Gulf FTS-1, upstream to CKT FTS				$3.1450	12	0.5832	1.0056	$22.1310	
14	TGP FTS-A, upstream to TCO FTS				$4.6238	12	0.4168	1.0218	$23.6316	
15										
16	Total Demand Cost of Assigned FTS, per unit								$79.7119	$83.6098
17										
18	100% Load Factor Rate (10 / 365 days)									$0.2291
19										
20										
	Balancing charge, paid by Choice marketers									
21	Demand Cost Recovery Factor in GCA, per Mcf per CKY Tariff Sheet No. 5									$1.1688
22	Less credit for cost of assigned capacity									($0.2291)
23	Plus storage commodity costs incurred by CKY for the Choice marketer									$0.1021
24										
25	Balancing Charge, per Mcf	sum(12:14)								$1.0419

COLUMBIA GAS OF KENTUCKY
CASE NO. 2010- Effective Sept 2010 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 23)	$1.3321	
Demand ACA (Schedule No. 2)	($0.1550)	
Total Refund Adjustment (Schedule No. 4)	($0.0081)	
SAS Refund Adjustment (Schedule No. 5)	($0.0002)	
Total Demand Rate per Mcf	$1.1688	<--- to Att. E, line 21
Commodity Component of Gas Cost Adjustment		
Commodity Cost of Gas (Schedule No. 1, Sheet 1, Line 22)	$5.8441	
Commodity ACA (Schedule No. 2)	($0.0916)	
Balancing Adjustment (Schedule No. 3)	$0.0299	
Gas Cost Incentive Adjustment (Schedule 6 Case No. 2010-00041)	$0.0042	
Total Commodity Rate per Mcf	$5.7866	
CHECK:	$1.1688	
	$5.7866	
COST OF GAS TO TARIFF CUSTOMERS (GCA)	$6.9554	
Calculation of Rate Schedule SVGTS - Actual Gas Cost Adjustment		
Commodity ACA (Schedule No. 2)	($0.0916)	
Balancing Adjustment (Schedule No. 3)	$0.0299	
Gas Cost Incentive Adjustment (Schedule No. 6 Case No. 2010-00041)	$0.0042	
Total Commodity Rate per Mcf	($0.0575)	

ACTUAL COST ADJUSTMENT

SCHEDULE NO. 2

COLUMBIA GAS OF KENTUCKY, INC.

STATEMENT SHOWING COMPUTATION OF ACTUAL GAS COST ADJUSTMENT (ACA) BASED ON THE TWELVE MONTHS ENDED JUNE 30, 2010

LINE NO.	MONTH	Total Sales Volumes Per Books Mcf (1)	Standby Service Sales Volumes Mcf (2)	Net Applicable Sales Volumes Mcf (3)=(1)-(2)	Average Expected Gas Cost Rate $/Mcf (4) = (5/3)	Gas Cost Recovery $ (5)	Standby Service Recovery $ (6)	Total Gas Cost Recovery $ (7)=(5)+(6)	Cost of Gas Purchased $ (8)	(OVER)/ UNDER RECOVERY $ (9)=(8)-(7)	Off System Sales (Accounting) (10)	Capacity Release Passback $ (11)	Information Only Marketed Capacity Release $ (12)
1	July 2009	364,833	615	364,218	$5.9118	$2,153,175	$39,535	$2,192,710	($1,901,798)	($4,094,508)	$67,531	$26,401	($132,147)
2	August 2009	28,665	288	28,377	$6.9339	$196,763	$37,444	$234,207	($2,600,928)	($2,835,135)	$8,066	$26,176	($131,675)
3	September 2009	172,869	156	172,713	$6.1559	$1,063,210	$36,600	$1,099,810	($28,358)	($1,128,168)	$47,148	$26,176	($131,650)
4	October 2009	322,393	276	322,117	$6.4449	$2,076,005	$36,271	$2,112,276	$4,435,698	$2,323,421	$50,073	$38,726	($155,789)
5	November 2009	684,267	2,529	681,738	$6.4638	$4,406,605	$41,625	$4,448,230	$7,108,123	$2,659,893	$30,128	$11,093	($104,619)
6	December 2009	1,336,277	3,191	1,333,086	$7.1633	$9,549,324	$43,198	$9,592,522	$21,709,910	$12,117,388	$52,727	$13,603	($108,846)
7	January 2010	2,441,117	5,693	2,435,424	$7.1327	$17,371,181	$52,977	$17,424,158	$22,023,016	$4,598,859	$419,663	$18,718	($117,923)
8	February 2010	2,216,494	3,024	2,213,470	$7.1259	$15,772,875	$44,835	$15,817,710	$20,291,620	$4,473,910	$374,753	$14,883	($109,748)
9	March 2010	1,839,896	3,814	1,836,082	$7.9984	$14,685,702	$47,245	$14,732,947	$5,669,403	($9,063,544)	$372,350	$19,911	($120,150)
10	April 2010	710,821	947	709,874	$7.9970	$5,676,847	$40,224	$5,717,072	($2,011,252)	($7,728,324)	$138,679	$1,918	($80,277)
11	May 2010	338,191	28	338,163	$7.9912	$2,702,321	$35,134	$2,737,455	$1,347,735	($1,389,720)	$51,986	$3,193	($85,821)
12	June 2010	225,012	0	225,012	$6.0327	$1,357,430	$34,991	$1,392,421	$53,680	($1,338,741)	$65,202	$4,782	($90,654)
13	TOTAL	10,680,835	20,561	10,660,274		$77,011,439	$490,079	$77,501,518	$76,096,849	($1,404,669)	$1,678,305	$205,577	($1,369,300)
14	Off-System Sales									($1,678,305)			
15	Capacity Release									($205,577)			
16	Gas Cost Audit									$0			
17	TOTAL (OVER)/UNDER-RECOVERY									($3,288,551)			
18	Demand Revenues Received									$14,931,092			
19	Demand Cost of Gas 1/									$12,628,225			
20	Demand (Over)/Under Recovery									($2,302,866)			
21	Expected Sales Volumes for the Twelve Months End Aug. 31, 2011									14,855,261			
22	**DEMAND ACA TO EXPIRE AUGUST 31, 2011**									**($0.1550)**			
23	Commodity Revenues Received									$62,570,438			
24	Commodity Cost of Gas									$61,584,741			
25	Commodity (Over)/Under Recovery									($985,696)			
26	Gas Cost Uncollectible ACA									($375,154)			
27	Total Commodity (Over)/Under Recovery									($1,360,850)			
28	Expected Sales Volumes for the Twelve Months End Aug. 31, 2011									14,855,261			
29	**COMMODITY ACA TO EXPIRE AUGUST 31, 2011**									**($0.0916)**			
30	**TOTAL ACA TO EXPIRE AUGUST 31, 2011**									**($0.2466)**			

1/ Per final order in case no. 2004-00462 dated March 29, 2005, Demand Cost of Gas shown is net of customer sharing credits of 50% of Capacity Release and Off System Sales profits, and credit for recovery through the SVAS Balancing Charge on Sheet 7a of the tariff.

STATEMENT SHOWING ACTUAL COST RECOVERY FROM CUSTOMERS TAKING STANDBY SERVICE UNDER RATE SCHEDULE IS AND GSO FOR THE TWELVE MONTHS ENDED JUNE 30, 2010

LINE NO.	MONTH	SS Commodity Volumes (1) Mcf	Average SS Recovery Rate (2) $/Mcf	SS Commodity Recovery (3) $
1	July 2009	615	$6.3955	$3,933
2	August 2009	288	$6.3955	$1,842
3	September 2009	156	$6.3955	$998
4	October 2009	276	$2.3762	$656
5	November 2009	2,529	$2.3762	$6,009
6	December 2009	3,191	$2.3762	$7,582
7	January 2010	5,693	$3.0506	$17,367
8	February 2010	3,024	$3.0506	$9,225
9	March 2010	3,814	$3.0506	$11,635
10	April 2010	947	$5.1130	$4,842
11	May 2010	28	$5.1129	$143
12	June 2010	-	$0.0000	$0
13	**Total SS Commodity Recovery**			$64,233

LINE NO.	MONTH	SS Demand Volumes (1) Mcf	Average SS Demand Rate (2) $/Mcf	SS Demand Recovery (3) $
14	July 2009	5,423	$6.5650	$35,602
15	August 2009	5,423	$6.5650	$35,602
16	September 2009	5,423	$6.5650	$35,602
17	October 2009	5,423	$6.5675	$35,616
18	November 2009	5,423	$6.5675	$35,616
19	December 2009	5,423	$6.5675	$35,616
20	January 2010	5,423	$6.5663	$35,609
21	February 2010	5,423	$6.5664	$35,610
22	March 2010	5,423	$6.5664	$35,610
23	April 2010	5,423	$6.5245	$35,382
24	May 2010	5,363	$6.5243	$34,990
25	June 2010	5,363	$6.5245	$34,991
26	**Total SS Demand Recovery**			$425,845
27	**TOTAL SS AND GSO RECOVERY**			$490,077

Columbia Gas of Kentucky, Inc.
Gas Cost Uncollectible Charge - Actual Cost Adjustment
For the 12 Months Ending June 30, 2010

Line	Class	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Total
1	**Actual Cost**	0.00	0.00	0.00	0.00	18,778.56	59,802.75	256,761.59	208,077.50	72,675.91	(149,922.72)	(56,817.82)	18,923.08	428,278.85
2	**Actual Recovery**	0.00	0.00	0.00	0.00	28,058.99	110,027.03	198,726.48	180,216.64	172,926.28	66,918.28	31,792.98	14,765.67	803,432.35
3	**(Over)/Under Activity**	**0.00**	**0.00**	**0.00**	**0.00**	**(9,280.43)**	**(50,224.28)**	**58,035.11**	**27,860.86**	**(100,250.37)**	**(216,841.00)**	**(88,610.80)**	**4,157.41**	**(375,153.50)**

BALANCE ADJUSTMENT

SCHEDULE NO. 3

COLUMBIA GAS OF KENTUCKY, INC.

CALCULATION OF BALANCING ADJUSTMENT
To Be Effective Billing Unit #1 September 2010

Line No.	Description	Detail $	Amount $
1	**RECONCILIATION OF A PREVIOUS SUPPLIER REFUND ADJUSTMENT**		
2	Total adjustment to have been distributed to		
3	customers in Case No. 2009-00036	($77,538)	
4	Less: Amount Distributed	($68,869)	
5	REMAINING AMOUNT		($8,669)
6	**RECONCILIATION OF GAS COST INCENTIVE ADJUSTMENT**		
7	Total adjustment to have been collected from		
8	customers in Case No. 2009-00036	$860,406	
9	Less: Amount Collected	$660,935	
10	REMAINING AMOUNT		$199,471
11	**RECONCILIATION OF A PREVIOUS BALANCING ADJUSTMENT**		
12	Total adjustment to have been collected from		
13	customers in Case No. 2009-00313	$554,130	
14	Less: Amount Collected	$514,231	
15	REMAINING AMOUNT		$39,899
16	**TOTAL BALANCING ADJUSTMENT AMOUNT**		**$230,701**
17	Divided by: Projected Sales Volumes for the six months		
18	ended February 28, 2011		7,714,946
19	**BALANCING ADJUSTMENT (BA) TO**		
20	**EXPIRE February 28, 2011**		**$ 0.0299**

Columbia Gas of Kentucky, Inc.
Supplier Refund Adjustment
Supporting Data

Case No. 2009-00036

Expires February 28, 2010	Volume	Refund Rate	Refund Amount	Refund Balance
				($77,538)
March 2009	1,527,735	($0.0053)	($8,097)	($69,441)
April 2009	951,588	($0.0053)	($5,043)	($64,398)
May 2009	456,926	($0.0053)	($2,422)	($61,976)
June 2009	261,526	($0.0053)	($1,386)	($60,590)
July 2009	352,911	($0.0053)	($1,870)	($58,719)
August 2009	36,208	($0.0053)	($192)	($58,527)
September 2009	162,748	($0.0053)	($863)	($57,665)
October 2009	318,640	($0.0053)	($1,689)	($55,976)
November 2009	677,489	($0.0053)	($3,591)	($52,385)
December 2009	1,326,462	($0.0053)	($7,030)	($45,355)
January 2010	2,404,320	($0.0053)	($12,743)	($32,612)
February 2010	2,182,225	($0.0053)	($11,566)	($21,046)
March 2010	13,986	($0.0053)	($74)	($20,972)

Summary:	
Refund Amount	($77,538)
Less: Amount Refunded	($56,566)
Less: Billing Adjustment	($12,303)
	($68,869)
Remaining Refund	($8,669)

Columbia Gas of Kentucky, Inc.
Gas Cost Incentive Adjustment
Supporting Data

Case No. 2009-00036

Expires February 28, 2010	Volume	Surcharge Rate	Surcharge Amount	Surcharge Balance
				$860,406
March 2009	1,607,637	$0.0584	$93,886	$766,520
April 2009	1,006,867	$0.0584	$58,801	$707,719
May 2009	491,107	$0.0584	$28,681	$679,038
June 2009	299,094	$0.0584	$17,467	$661,571
July 2009	375,200	$0.0584	$21,912	$639,660
August 2009	52,508	$0.0584	$3,066	$636,593
September 2009	182,491	$0.0584	$10,657	$625,936
October 2009	347,822	$0.0584	$20,313	$605,623
November 2009	725,632	$0.0584	$42,377	$563,246
December 2009	1,404,589	$0.0584	$82,028	$481,218
January 2010	2,527,641	$0.0584	$147,614	$333,604
February 2010	2,282,799	$0.0584	$133,315	$200,288
March 2010	13,986	$0.0584	$817	$199,471

Summary:	
Surcharge Amount	$860,406
Less: Amount Collected	$660,935
Remaining Amount	$199,471

Columbia Gas of Kentucky, Inc.
Balancing Adjustment
Supporting Data

Case No. 2009-00313

Expires February 28, 2010	Volume	Surcharge Rate	Surcharge Amount	Surcharge Balance
Beginning Balance				$554,130
September 2009	185,051	$0.0691	$12,787	$541,343
October 2009	347,822	$0.0691	$24,035	$517,308
November 2009	725,632	$0.0691	$50,141	$467,167
December 2009	1,406,052	$0.0691	$97,158	$370,009
January 2010	2,527,641	$0.0691	$174,660	$195,349
February 2010	2,282,799	$0.0691	$157,741	$37,608
March 2010	13,986	$0.0691	$966	$36,641

Summary:	
Surcharge Amount	$554,130
Plus: Adjustment	$3,258
Less: Amount Collected	$517,489
Total Remaining	$39,899

SAS REFUND ADJUSTMENT

SCHEDULE NO. 5

COLUMBIA GAS OF KENTUCKY, INC.

SPECIAL AGENCY SERVICE
ACTUAL SAS VOLUMES DELIVERED
FOR THE TWELVE MONTHS ENDED JUNE 30, 2010

Line No.	Month	SAS Volumes Delivered (Mcf)
1	July 2009	1,283
2	August 2009	1,499
3	September 2009	1,358
4	October 2009	3,304
5	November 2009	5,031
6	December 2009	7,319
7	January 2010	8,502
8	February 2010	7,773
9	March 2010	5,565
10	April 2010	1,735
11	May 2010	1,391
12	June 2010	1,120
13	TOTAL SAS VOLUMES DELIVERED	45,880
14	**TOTAL AGENCY FEE TO BE REFUNDED**	($2,294.00)
15	(Line No. 13 * $0.05 per MCF)	
16	DIVIDED BY: Projected Sales for the TME August 31, 2011	14,855,261
17	**ANNUAL AGENCY FEE REFUND ADJUSTMENT**	**($0.0002)**
18	**(EXPIRES AUGUST 31, 2011)**	

PIPELINE COMPANY TARIFF SHEETS

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) $
Rate Schedule FTS-1					
Rayne, LA To Points North					
Reservation Charge 2/	3.1450	-	3.1450	3.1450	0.1034
Commodity					
Maximum	0.0170	0.0019	0.0189	0.0189	0.0189
Minimum	0.0170	0.0019	0.0189	0.0189	0.0189
Overrun	0.1204	0.0019	0.1223	0.1223	0.1223

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).

Currently Effective Rates
Applicable to Rate Schedule FTS, NTS and NTS-S
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									
Reservation Charge 3/	$	5.615	0.338	0.048	0.057	0.017	-	6.075	0.1998
Commodity									
Maximum	¢	1.04	0.43	0.13	0.61	0.05	0.19	2.45	2.45
Minimum	¢	1.04	0.43	0.13	0.61	0.05	0.19	2.45	2.45
Overrun	¢	19.50	1.54	0.29	0.80	0.11	0.19	22.43	22.43
Rate Schedule NTS									
Reservation Charge 3/4/	$	7.130	0.338	0.048	0.057	0.017	-	7.590	0.2496
Commodity									
Maximum	¢	1.04	0.43	0.13	0.61	0.05	0.19	2.45	2.45
Minimum	¢	1.04	0.43	0.13	0.61	0.05	0.19	2.45	2.45
Overrun	¢	24.48	1.54	0.29	0.80	0.11	0.19	27.41	27.41

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. 35.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ Minimum reservation charge is $0.00.
4/ The rates shown above for Service under Rate Schedule NTS shall be applicable to Service under Rate Schedule NTS-S except that the maximum Reservation Fee shall be adjusted to reflect the applicable expedited period of gas flow (EPF) utilizing the following formula, rounded to 3 decimal places:
NTS-S = NTS * (24/EPF) where:
NTS-S = NTS-S Reservation Fee
NTS = Applicable NTS Reservation Fee
24 = Number of Hours in a Gas Day
EPF - MDQ/MHQ

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/ 4/	$	5.445	0.338	0.048	0.057	0.017	-	5.905	0.1942
Commodity									
Maximum	¢	1.02	0.43	0.13	0.61	0.05	0.19	2.43	2.43
Minimum	¢	1.02	0.43	0.13	0.61	0.05	0.19	2.43	2.43
Overrun 4/	¢	18.92	1.54	0.29	0.80	0.11	0.19	21.85	21.85
Rate Schedule GTS									
Commodity									
Maximum	¢	74.84	2.65	0.45	0.98	0.16	0.19	79.27	79.27
Minimum	¢	3.08	0.43	0.13	0.61	0.05	0.19	4.49	4.49
MFCC	¢	71.76	2.22	0.32	0.37	0.11	-	74.78	74.78

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. 35.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ Minimum reservation charge is $0.00.
4/ In addition to the above reflected Base Tariff SST Demand Rate, shippers utilizing the Eastern Market Expansion (EME) facilities for Rate Schedule SST service will pay an additional demand charge of $12.180 per Dth per month, for a total SST reservation charge of $17.625. If EME customers incur an overrun for SST services that is provided under their EME Project service agreements, they will pay an additional 40.05 cents for such overruns, for a total overrun rate of 58.97 cents. The applicable EME demand charge and EME overrun charge can be added to the Total Effective Rate above to calculate the EME Total Effective Rates.

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 3/	$	1.506	-	-	-	-	-	1.506	0.0495
Capacity 3/	¢	2.89	-	-	-	-	-	2.89	2.89
Injection	¢	1.53	-	-	-	-	-	1.53	1.53
Withdrawal	¢	1.53	-	-	-	-	-	1.53	1.53
Overrun 3/	¢	10.90	-	-	-	-	-	10.90	10.90
Rate Schedule ISS									
Commodity									
Maximum	¢	5.95	-	-	-	-	-	5.95	5.95
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	¢	4.12	-	-	-	-	-	4.12	4.12
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.
3/ In addition to the above reflected Base Tariff Reservation Charge (MDSQ) and Capacity (SCQ) Rate, shippers utilizing the Eastern Market Expansion (EME) facilities for FSS service will pay an additional incremental reservation charge of $2.624 per Dth per month, for a total FSS MDSQ reservation charge of $4.130 and an additional 3.91 cents per Dth per month, for a total FSS SCQ capacity rate of 6.80 cents. If EME customers incur an overrun for FSS services that is provided under their EME Project service agreements, they will pay an additional 12.54 cents for such overruns, for a total FSS overrun rate of 23.44 cents. The additional EME demand charges and EME overrun charges can be added to the Total Effective Rate above to develop the EME Total Effective Rate.

Currently Effective Rates
Applicable to Rate Schedules FTS and ITS
Rate per Dth

		Base Tariff Rate	Annual Charge Adjustment	Total Effective Rate	Daily Rate
Rate Schedule FTS					
Reservation Charge					
Maximum	$	0.509	-	0.509	0.0167
Minimum	$	0.509	-	0.509	0.0167
Commodity Charge					
Maximum	¢	0.00	0.19	0.19	0.19
Minimum	¢	0.00	0.19	0.19	0.19
Overrun	¢	1.67	0.19	1.86	1.86
Rate Schedule ITS					
Commodity Charge					
Maximum	¢	1.67	0.19	1.86	1.86
Minimum	¢	1.67	0.19	1.86	1.86

RETAINAGE PERCENTAGE
Transportation Retainage 0.677%

PROPOSED TARIFF SHEETS

CURRENTLY EFFECTIVE BILLING RATES

SALES SERVICE	Base Rate Charge $	Gas Cost Adjustment[1/] Demand $	Gas Cost Adjustment[1/] Commodity $	Total Billing Rate $	
RATE SCHEDULE GSR					
Customer Charge per billing period	12.35			12.35	
Delivery Charge per Mcf	1.8715	1.1688	5.7866	8.8269	I
RATE SCHEDULE GSO					
Commercial or Industrial					
Customer Charge per billing period	25.13			25.13	
Delivery Charge per Mcf -					
First 50 Mcf or less per billing period	1.8715	1.1688	5.7866	8.8269	I
Next 350 Mcf per billing period	1.8153	1.1688	5.7866	8.7707	I
Next 600 Mcf per billing period	1.7296	1.1688	5.7866	8.6850	I
Over 1,000 Mcf per billing period	1.5802	1.1688	5.7866	8.5356	I
RATE SCHEDULE IS					
Customer Charge per billing period	583.39			583.39	
Delivery Charge per Mcf					
First 30,000 Mcf per billing period	0.5467		5.7866 [2/]	6.3333	I
Over 30,000 Mcf per billing period	0.2905		5.7866 [2/]	6.0771	I
Firm Service Demand Charge					
Demand Charge times Daily Firm					
Volume (Mcf) in Customer Service Agreement		6.5273		6.5273	
RATE SCHEDULE IUS					
Customer Charge per billing period	331.50			331.50	
Delivery Charge per Mcf					
For All Volumes Delivered	0.7750	1.1688	5.7866	7.7304	I

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 or IUS and received service under Rate Schedule SVGTS shall be $7.1762 per Mcf only for those months of the prior twelve months during which they were served under Rate Schedule SVGTS I

2/ IS Customers may be subject to the Demand Gas Cost, under the conditions set forth on Sheets 14 and 15 of this tariff.

I – Increase **R - Reduction**

DATE OF ISSUE: July 27, 2010

DATE EFFECTIVE: August 27, 2010
(September Unit 1 Billing)

ISSUED BY: Herbert A. Miller, Jr.

President

CURRENTLY EFFECTIVE BILLING RATES

(Continued)

TRANSPORTATION SERVICE	Base Rate Charge $	Gas Cost Adjustment[1/] Demand $	Gas Cost Adjustment[1/] Commodity $	Total Billing Rate $	
RATE SCHEDULE SS					
Standby Service Demand Charge per Mcf					
Demand Charge times Daily Firm					
Volume (Mcf) in Customer Service Agreement		6.5273		6.5273	
Standby Service Commodity Charge per Mcf			5.7866	5.7866	I
RATE SCHEDULE DS					
Administrative Charge per account per billing period				55.90	
Customer Charge per billing period [2/]				583.39	
Customer Charge per billing period (GDS only)				25.13	
Customer Charge per billing period (IUDS only)				331.50	
Delivery Charge per Mcf[2/]					
First 30,000 Mcf	0.5467			0.5467	
Over 30,000 Mcf	0.2905			0.2905	
– Grandfathered Delivery Service					
First 50 Mcf or less per billing period				1.8715	
Next 350 Mcf per billing period				1.8153	
Next 600 Mcf per billing period				1.7296	
All Over 1,000 Mcf per billing period				1.5802	
– Intrastate Utility Delivery Service					
All Volumes per billing period				0. 7750	
Banking and Balancing Service					
Rate per Mcf		0.0208		0.0208	
RATE SCHEDULE MLDS					
Administrative Charge per account each billing period				55.90	
Customer Charge per billing period				200.00	
Delivery Charge per Mcf				0.0858	
Banking and Balancing Service					
Rate per Mcf		0.0208		0.0208	

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/ Applicable to all Rate Schedule DS customers except those served under Grandfathered Delivery Service or Intrastate Utility Delivery Service.

I – Increase **R - Reduction**

DATE OF ISSUE: July 27, 2010 **DATE EFFECTIVE:** August 27, 2010 (September Unit 1 Billing)

ISSUED BY: Herbert A. Miller, Jr. President

CURRENTLY EFFECTIVE BILLING RATES

		Billing Rate $	
RATE SCHEDULE SVGTS			
General Service Residential			
Customer Charge per billing period		12.35	
Delivery Charge per Mcf		1.8715	
General Service Other - Commercial or Industrial			
Customer Charge per billing period		25.13	
Delivery Charge per Mcf -			
First 50 Mcf or less per billing period		1.8715	
Next 350 Mcf per billing period		1.8153	
Next 600 Mcf per billing period		1.7296	
Over 1,000 Mcf per billing period		1.5802	
Intrastate Utility Service			
Customer Charge per billing period		331.50	
Delivery Charge per Mcf		$ 0.7750	
Actual Gas Cost Adjustment [1/]			
For all volumes per billing period per Mcf	($ 0.0575)		I
RATE SCHEDULE SVAS			
Balancing Charge – per Mcf	$ 1.0419		R

I – Increase **R - Reduction**

1/ The Gas Cost Adjustment is applicable to a customer who is receiving service under Rate Schedule SVGTS and received service under Rate Schedule GS, IS, or IUS for only those months of the prior twelve months during which they were served under Rate Schedule GS, IS or IUS.

DATE OF ISSUE: July 27, 2010

DATE EFFECTIVE: August 27, 2010
(September Unit 1 Billing)

ISSUED BY: Herbert A. Miller,

President