Columbia Gas of Kentucky

A NiSource Company

August 1, 2016

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PUBLIC SERVICE COMMISSION

Ms. Talina Mathews
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602

Re: Gas Cost Adjustment, **Case No. 2016 –** 00285

Dear Ms. Mathews:

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 \$0.3368 per Mcf effective with its September 2016 billing cycle on August 29, 2016. The increase is composed of an increase of \$0.6623 per Mcf in the Average Commodity Cost of Gas, an increase of \$0.0005 per Mcf in the Average Demand Cost of Gas, an increase of \$0.0755 per Mcf in the Balancing Adjustment, an increase of \$0.0006 per Mcf in the Supplier Refund Adjustment, and a decrease of (\$0.4021) in the Actual Cost Adjustment. Pursuant to Case No. 2016-00060 Columbia has implemented a quarterly Actual Cost Adjustment and Balancing Adjustment effective with the June 2016 billing cycle.

This adjustment was prepared to be filed on Friday, July 29, 2016, more than 30 days notice in advance of the proposed effective date. However, due to problems with Columbia's IT system, the filing was not able to be submitted on Friday. Therefore, and with apologies for the inconvenience, whether this may be considered the regular quarterly filing or an interim adjustment, Columbia requests the Commission authorize a notice period of 28 days pursuant to KRS § 278.180,so that the change in rates may be effective on August 29, 2016, the first day of Columbia's September billing cycle.

Please feel free to contact Judy Cooper at (859) 288-0242 or jmcoop@nisource.com if there are any questions.

Sincerely,

Stephen B. Seiple (jmc)

Stephen B. Seiple
Assistant General Counsel

Enclosures

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PUBLIC SERVICE
COMMISSION

BEFORE THE
PUBLIC SERVICE COMMISSION
OF KENTUCKY

COLUMBIA GAS OF KENTUCKY, INC.

CASE 2016 – 00285

GAS COST ADJUSTMENT AND REVISED RATES OF
COLUMBIA GAS OF KENTUCKY, INC. PROPOSED TO BECOME
EFFECTIVE SEPTEMBER 2016 BILLINGS

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

Line No.		June-16 CURRENT	September-16 PROPOSED	DIFFERENCE
1	Commodity Cost of Gas	$2.3814	$3.0437	$0.6623
2	Demand Cost of Gas	$1.4722	$1.4727	$0.0005
3	Total: Expected Gas Cost (EGC)	$3.8536	$4.5164	$0.6628
4	SAS Refund Adjustment	$0.0000	$0.0000	$0.0000
5	Balancing Adjustment	($0.0755)	$0.0000	$0.0755
6	Supplier Refund Adjustment	($0.0016)	($0.0010)	$0.0006
7	Actual Cost Adjustment	($1.9527)	($2.3548)	($0.4021)
8	Performance Based Rate Adjustment	$0.3668	$0.3668	$0.0000
9	Cost of Gas to Tariff Customers (GCA)	$2.1906	$2.5274	$0.3368
10	Transportation TOP Refund Adjustment	$0.0000	$0.0000	$0.0000
11	Banking and Balancing Service	$0.0209	$0.0209	$0.0000
12	Rate Schedule FI and GSO			
13	Customer Demand Charge	$6.8121	$6.8133	$0.0012

Columbia Gas of Kentucky, Inc.
Gas Cost Adjustment Clause
Gas Cost Recovery Rate
Sep - Nov 16

Line No.	Description			Amount	Expires
1	Expected Gas Cost (EGC)	Schedule No. 1		$4.5164	11-30-16
2	Actual Cost Adjustment (ACA)	Schedule No. 2		($2.3548)	Various
3	Supplier Refund Adjustment (RA)	Schedule No. 4		($0.0010)	08-31-17
4	Balancing Adjustment (BA)	Schedule No. 3		$0.0000	11-30-16
5	Performance Based Rate Adjustment (PBRA)	Schedule No. 6	Case No. 2016-00166	$0.3668	05-31-17
6	Gas Cost Adjustment				
7	Sep - Nov 16			$2.5274	
8	Expected Demand Cost (EDC) per Mcf				
9	(Applicable to Rate Schedule IS/SS and GSO)	Schedule No. 1, Sheet 4		$6.8133	

DATE FILED: July 28, 2016 **BY: J. M. Cooper**

Columbia Gas of Kentucky, Inc. Schedule No. 1

Expected Gas Cost for Sales Customers Sheet 1

Sep - Nov 16

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				(1,060,000)		$0.0153	$16,218
2	Injection				1,505,000		$0.0153	$23,027
3	Withdrawals: gas cost includes pipeline fuel and commodity charges				1,060,000		$2.6576	$2,817,056
	Total							
4	Volume	= 3			1,060,000			
5	Cost	sum(1:3)						$2,856,301
6	Summary	4 or 5			1,060,000			$2,856,301
	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		762,000			$2,011,680
8	Appalachian Supplies		Sch.1, Sht. 6, Ln. 4		57,000			$185,000
9	Less Fuel Retention By Interstate Pipelines		Sch. 1,Sheet 7, Lines 21, 22		(73,000)			($215,234)
10	Total	7 + 8 + 9			746,000			$1,981,446
	Total Supply							
11	At City-Gate		Line 6 + 10		1,806,000			$4,837,747
	Lost and Unaccounted For							
12	Factor				-1.4%			
13	Volume		Line 11 * 12		(25,284)			
14	At Customer Meter		Line 11 + 13	1,667,337	1,780,716			
15	Less: Right-of-Way Contract Volume			476				
16	**Sales Volume**		Line 14-15	1,666,861				
	Unit Costs $/MCF							
	Commodity Cost							
17	Excluding Cost of Pipeline Retention		Line 11 / Line 16			$2.9023		
18	Annualized Unit Cost of Retention		Sch. 1,Sheet 7, Line 24			$0.1242		
19	Including Cost of Pipeline Retention		Line 17 + 18			$3.0265		
20	Uncollectible Ratio		CN 2013-00167			0.00568963		
21	Gas Cost Uncollectible Charge		Line 19 * Line 20			$0.0172		
22	Total Commodity Cost		line 19 + line 21			$3.0437		
23	Demand Cost		Sch.1, Sht. 2, Line 10			$1.4727		
24	Total Expected Gas Cost (EGC)		Line 22 + 23			$4.5164		

A/ BTU Factor = 1.0680 Dth/MCF

Columbia Gas of Kentucky, Inc.
GCA Unit Demand Cost
Sep - Nov 16

Schedule No. 1
Sheet 2

Line No.	Description		Reference		
1	Expected Demand Cost: Annual Sep - Aug 2017		Sch. No.1, Sheet 3, Ln. 11	$20,584,973	
2	Less Rate Schedule IS/SS and GSO Customer Demand Charge Recovery		Sch. No.1, Sheet 4, Ln. 10	-$270,788	
3	Less Storage Service Recovery from Delivery Service Customers			-$172,092	
4	Net Demand Cost Applicable	1 + 2 + 3		$20,142,093	
	Projected Annual Demand: Sales + Choice				
	At city-gate				
	In Dth			14,818,000	Dth
	Heat content			1.0680	Dth/MCF
5	In MCF			13,874,532	MCF
	Lost and Unaccounted - For				
6	Factor			1.4%	
7	Volume	5 * 6		194,243	MCF
8	Right of way Volumes			3,006	
9	At Customer Meter	5 - 7- 8		13,677,283	MCF
10	Unit Demand Cost (4/ 9)	To Sheet 1, line 23		$1.4727	per MCF

Columbia Gas of Kentucky, Inc.
Annual Demand Cost of Interstate Pipeline Capacity
Sep - Aug 2017

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	$1.5010	12	$3,978,491
2	FSS Seasonal Contract Quantity (SCQ)		11,264,911	$0.0288	12	$3,893,153
	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	$6.1900	12	$1,486,640
6	Subtotal	sum(1:5)				$17,677,729
	Columbia Gulf Transmission Company					
7	FTS - 1 (Mainline)		28,991	$4.2917	12	$1,493,048
	Tennessee Gas					
8	Firm Transportation		20,506	$4.5823	12	$1,127,576
	Central Kentucky Transmission					
9	Firm Transportation		28,000	$0.5090	12	$171,024
10	Operational and Commercial Services Charge			$9,633	12	$115,596
11	**Total.** Used on Sheet 2, line 1					$20,584,973

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

Sep - Aug 2017

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)						$20,584,973
	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				1.068	Dth/MCF	
7	Total Capacity - Annualized	Line 5/ Line 6			3,021,281	Mcf	
8	Monthly Unit Expected Demand Cost (EDC) of Daily Capacity Applicable to Rate Schedules IS/SS and GSO Line 1 / Line 7				$6.8133	/Mcf	
9	Firm Volumes of IS/SS and GSO Customers		3,312	12	39,744	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		$270,788

Columbia Gas of Kentucky, Inc.
Non-Appalachian Supply: Volume and Cost
Sep - Nov 16

Schedule No. 1
Sheet 5

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-16	1,409,000	$3,681,000		(1,200,000)	209,000	
2	Oct-16	807,000	$2,143,000		(305,000)	502,000	
3	Nov-16	51,000	$166,000		0	51,000	
4	Total 1+2+3	2,267,000	$5,990,000	$2.64	(1,505,000)	762,000	$2,011,680

A/ Gross, before retention.

Columbia Gas of Kentucky, Inc.
Appalachian Supply: Volume and Cost
Sep - Nov 16

Schedule No. 1
Sheet 6

Line No.	Month		Dth (2)	Cost (3)
1	Sep-16		16,000	$49,000
2	Oct-16		17,000	$52,000
3	Nov-16		24,000	$84,000
4	Total	1 + 2 + 3	57,000	$185,000

Columbia Gas of Kentucky, Inc.
Annualized Unit Charge for Gas Retained by Upstream Pipelines
Sep - Nov 16

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

			Units	Sep - Nov 16	Dec - Feb 17	Mar - May 17	Jun - Aug 17	Annual Sep - Aug 2017
	Gas purchased by CKY for the remaining sales customers							
1	Volume		Dth	2,324,000	1,541,000	3,114,000	4,263,000	11,242,000
2	Commodity Cost Including Transportation			$6,175,000	$5,148,000	$9,144,000	$12,679,000	$33,146,000
3	Unit cost		$/Dth					$2.9484
	Consumption by the remaining sales customers							
11	At city gate		Dth	1,806,000	6,136,000	2,307,000	514,000	10,763,000
12	Lost and unaccounted for portion			1.40%	1.40%	1.40%	1.40%	
	At customer meters							
13	In Dth	(100% - 12) * 11	Dth	1,780,716	6,050,096	2,274,702	506,804	10,612,318
14	Heat content		Dth/MCF	1.0680	1.0680	1.0680	1.0680	
15	In MCF	13 / 14	MCF	1,667,337	5,664,884	2,129,871	474,536	9,936,628
16	Portion of annual	line 15, quarterly / annual		16.8%	57.0%	21.4%	4.8%	100.0%
	Gas retained by upstream pipelines							
21	Volume		Dth	73,000	156,000	96,000	93,000	418,000
	Cost			To Sheet 1, line 9				
22	Quarterly. Deduct from Sheet 1	3 * 21		$215,234	$459,952	$283,047	$274,202	$1,232,435
23	Allocated to quarters by consumption			$207,049	$702,488	$263,741	$59,157	$1,232,435
				To Sheet 1, line 18				
24	Annualized unit charge	23 / 15	$/MCF	$0.1242	$0.1240	$0.1238	$0.1247	$0.1240

COLUMBIA GAS OF KENTUCKY, INC.

Schedule No. 1

Sheet 8

DETERMINATION OF THE BANKING AND
BALANCING CHARGE
FOR THE PERIOD BEGINNING SEPTEMBER 2016

Line No.	Description	Dth	Detail	Amount For Transportation Customers
1	Total Storage Capacity. Sheet 3, line 2	11,264,911		
2	Net Transportation Volume	8,812,069		
3	Contract Tolerance Level @ 5%	440,603		
4	Percent of Annual Storage Applicable			
5	to Transportation Customers		3.91%	
6	Seasonal Contract Quantity (SCQ)			
7	Rate		$0.0288	
8	SCQ Charge - Annualized		$3,893,153	
9	Amount Applicable To Transportation Customers			$152,222
10	FSS Injection and Withdrawal Charge			
11	Rate		0.0306	
12	Total Cost		$344,706	
13	Amount Applicable To Transportation Customers			$13,478
14	SST Commodity Charge			
15	Rate		0.0193	
16	Projected Annual Storage Withdrawal, Dth		8,470,000	
17	Total Cost		$163,471	
18	Amount Applicable To Transportation Customers			$6,392
19	Total Cost Applicable To Transportation Customers			$172,092
20	Total Transportation Volume - Mcf			19,318,001
21	Flex and Special Contract Transportation Volume - Mcf			(11,067,000)
22	Net Transportation Volume - Mcf	line 20 + line 21		8,251,001
23	Banking and Balancing Rate - Mcf.	Line 19 / line 22. To line 11 of the GCA Comparison		$0.0209

DETAIL SUPPORTING

DEMAND/COMMODITY SPLIT

COLUMBIA GAS OF KENTUCKY
CASE NO. 2016- Effective September 2016 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)	$1.4727	
Demand ACA (Schedule No. 2, Sheet 1, Case No. 2015-00270, Case No. 2016-00166 & Case No. 2016-)	($0.0523)	
Refund Adjustment (Schedule No. 4, Case No. 2016-)	($0.0010)	
Total Demand Rate per Mcf	$1.4194	<--- to Att. E, line 15
Commodity Component of Gas Cost Adjustment		
Commodity Cost of Gas (Schedule No. 1, Sheet 1, Line 22)	$3.0437	
Commodity ACA (Schedule No. 2, Sheet 1, Case No. 2015-00270, Case No. 2016-00166 & Case No. 2016-)	($2.3025)	
Balancing Adjustment	$0.0000	
Performance Based Rate Adjustment (Schedule No. 6, Case No. 2016-00166)	$0.3668	
Total Commodity Rate per Mcf	$1.1080	
CHECK:	$1.4194	
	$1.1080	
COST OF GAS TO TARIFF CUSTOMERS (GCA)	$2.5274	

Calculation of Rate Schedule SVGTS - Actual Gas Cost Adjustment

Commodity ACA (Schedule No. 2, Sheet 1, Case No. 2015-00270, Case No. 2016-00166 & Case No. 2016-)	($2.3025)
Balancing Adjustment	$0.0000
Performance Based Rate Adjustment (Schedule No. 6, Case No. 2016-00166)	$0.3668
Total Commodity Rate per Mcf	($1.9357)

Columbia Gas of Kentucky, Inc.
CKY Choice Program
100% Load Factor Rate of Assigned FTS Capacity
Balancing Charge
Sep - Nov 16

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	0.663%						
3	TCO FTS		20,014	2.042%						
4	Total		48,014							
5										
6	Assignment Proportions									
7	CKT FTS/SST	2 / 4	58.32%							
8	TCO FTS	3 / 4	41.68%							
	Annual demand cost of capacity assigned to choice marketers									
9	CKT FTS				$0.5090	12	0.5832	1.0000	$3.5622	
10	TCO FTS				$6.1900	12	0.4168	1.0000	$30.9599	
11	Gulf FTS-1, upstream to CKT FTS				$4.2917	12	0.5832	1.0067	$30.2355	
12	TGP FTS-A, upstream to TCO FTS				$4.5823	12	0.4168	1.0208	$23.3966	
13	Total Demand Cost of Assigned FTS, per unit								$88.1542	$94.1487
14	100% Load Factor Rate (Line 13 / 365 days)									$0.2579
	Balancing charge, paid by Choice marketers									
15	Demand Cost Recovery Factor in GCA, per Mcf per CKY Tariff Sheet No. 5									$1.4194
16	Less credit for cost of assigned capacity									($0.2579)
17	Plus storage commodity costs incurred by CKY for the Choice marketer									$0.0668
18	Balancing Charge, per Mcf sum(15:17)									$1.2283

ACTUAL COST ADJUSTMENT

SCHEDULE NO. 2

COLUMBIA GAS OF KENTUCKY, INC.

STATEMENT SHOWING COMPUTATION OF ACTUAL GAS COST ADJUSTMENT (ACA) BASED ON THE THREE MONTHS ENDED MAY 31, 2016

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)	Gas Left On Recovery (7)	Total Gas Cost Recovery $ (8)=(5)+(6)-(7)	Cost of Gas Purchased $ (9)	(OVER)/ UNDER RECOVERY $ (10)=(9)-(8)	Off System Sales (Accounting) (11)	Capacity Release Passback $ (12)	Information Only Capacity Release $ (13)
1	March 2016	1,312,941	588	1,312,353	$4.2953	$5,637,013	$24,496	($1,778)	$5,663,286	$1,740,338	($3,922,948)	$51,426	$0	($77,042)
2	April 2016	766,090	813	765,277	$4.2928	$3,285,177	$24,915	($1,831)	$3,311,924	$3,326,155	$14,231	$95,222	$0	($77,852)
3	May 2016	402,300	636	401,664	$4.2951	$1,725,187	$24,417	($1,041)	$1,750,645	$1,897,355	$146,710	$88,360	$0	($75,450)
4	TOTAL	2,481,331	2,037	2,479,294		$10,647,378	$73,828	($4,650)	$10,725,856	$6,963,848	($3,762,007)	$235,007	$0	($230,345)

Line No.		(10)
5	Off-System Sales	($235,007)
6	Capacity Release	$0
7	Gas Cost Audit	$0
8	TOTAL (OVER)/UNDER-RECOVERY	($3,997,015)
9	Demand Revenues Received	$3,725,274
10	Demand Cost of Gas 1/	$3,423,254
11	Demand (Over)/Under Recovery	($302,020)
12	Expected Sales Volumes for the Twelve Months End August 31, 2017	9,933,621
13	**DEMAND ACA TO EXPIRE AUGUST 31, 2017**	**($0.0304)**
14	Commodity Revenues Received	$6,995,932
15	Commodity Cost of Gas	$3,305,587
16	Commodity (Over)/Under Recovery	($3,690,344)
17	Gas Cost Uncollectible ACA	($1,582)
18	Total Commodity (Over)/Under Recovery	($3,691,926)
19	Expected Sales Volumes for the Twelve Months End August 31, 2017	9,933,621
20	**COMMODITY ACA TO AUGUST MAY 31, 2017**	**($0.3717)**
21	**TOTAL ACA TO EXPIRE AUGUST 31, 2017**	**($0.4021)**

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 THREE MONTHS ENDED MAY 31, 2016

LINE NO.	MONTH	SS Commodity Volumes (1) Mcf	Average SS Recovery Rate (2) $/Mcf	SS Commodity Recovery (3) $
1	March 2016	588	$3.2993	$1,940
2	April 2016	813	$2.8155	$2,289
3	May 2016	636	$2.8155	$1,791
4	**Total SS Commodity Recovery**			$6,020

LINE NO.	MONTH	SS Demand Volumes (1) Mcf	Average SS Demand Rate (2) $/Mcf	SS Demand Recovery (3) $
5	March 2016	3,312	$6.8103	$22,556
6	April 2016	3,312	$6.8316	$22,626
7	May 2016	3,312	$6.8316	$22,626
8	**Total SS Demand Recovery**			$67,808
9	**TOTAL SS AND GSO RECOVERY**			$73,828

Columbia Gas of Kentucky, Inc.
Gas Cost Uncollectible Charge - Actual Cost Adjustment
For the Three Months Ending May 31, 2016

Line No.	Class	Mar-16	Apr-16	May-16	Total
1	Actual Cost	$ 9,218	$ 16,439	$ 12,564	$ 38,220
2	Actual Recovery	$ 21,061	$ 12,298	$ 6,443	$ 39,802
3	(Over)/Under Activity	$ (11,844)	$ 4,141	$ 6,120	$ (1,582)

Columbia Gas of Kentucky, Inc.
Actual Cost Adjustment Summary of Rates
For the Period Beginning Billing Unit 1 September 2016

Line No.	Effective Month	Expiration Month	Case Number	ACA Rate
1	September 2015	August 2016	2015-00270	$ (1.9760)
2	June 2016	May 2017	2016-00166	$ 0.0233
2	September 2016	August 2017	2016-xxxxx	$ (0.4021)
3	Cumulative Rate			$ (1.9527)

REFUND ADJUSTMENT

SCHEDULE NO. 4

COLUMBIA GAS OF KENTUCKY, INC.

SUPPLIER REFUND ADJUSTMENT

Line No.	Description	Amount
1	Columbia Gas Transmission Settlement Refund	($13,850)
2	Interest on Refund Balances	$0
3	Total Refund	($13,850)
4	Projected Sales for the Twelve Months Ended August 31, 2016	13,677,283
5	**TOTAL SUPPLIER REFUND TO EXPIRE August 31, 2017**	**($0.0010)**

Columbia Pipeline Group

5151 San Felipe, Suite 2400
Houston, Texas 77056
Phone: 713-386-3759
Fax: 713-386-3755
jdowns@cpg.com

Jim Downs
Vice President of Rates & Regulatory Affairs

June 10, 2016

Ms. Kimberly D. Bose
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: *Columbia Gas Transmission, LLC*, Docket No. RP16-314-000 and RP16-864-____
Settlement Refund Report

Dear Secretary Bose:

Pursuant to Sections 154.501 and 154.502 of the Federal Energy Regulatory Commission's ("Commission") regulations,[1] and Article III of the Stipulation and Agreement ("Settlement") approved by the Commission on March 17, 2016,[2] Columbia Gas Transmission, LLC ("Columbia") hereby submits its report regarding the refund provided to shippers as the result of the resolution of Columbia's Modernization II settlement in this proceeding.

Statement of Nature, Basis and Reasons

On December 18, 2015, Columbia filed a Stipulation and Agreement of Settlement ("Settlement") representing an extension to its modernization program – a collaborative program between Columbia and its customers to address complex issues arising out of recent and anticipated changes in pipeline safety and environmental requirements, Columbia's ongoing efforts to enhance pipeline safety and reliability of service, and the age of Columbia's system. On March 17, 2016, the Commission approved the settlement on the basis that it is fair and reasonable and in the public interest.[3]

The Settlement provides for a base rate reduction applicable to specified transportation rate schedules. Effective January 1, 2016, to reflect the termination of Columbia's obligations associated with its "Post Retirement Benefits Other Than Pensions" ("PBOP"), Columbia will reduce its base rates by $8,367,554 annually. Additionally, to reflect the amortization of the PBOP regulatory liability, Columbia will reduce its Base Rates by approximately $12.2 million annually.

In addition, Article III of the Settlement provided that Columbia would refund, in the next monthly billing cycle that is at least 15 days after the Final Order approving the Stipulation, the difference between the currently effective Base Rates and the Settlement Base Rates for the time period beginning January 1, 2016 through the date the Settlement Base Rates become effective.

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[1] 18 C.F.R §154.502 (2016).
[2] *Columbia Gas Transmission, LLC,* 142 FERC ¶ 61,062 (2013) ("January 24 Order").
[3] *Columbia Gas Transmission, LLC,* 154 FERC ¶ 61,208 P 18 (2016) ("March 17 Order").

The Commission issued its order on the Settlement on March 17, 2016 and, pursuant to Article XI, the order did not become a Final Order until April 17, 2016.[4] In accordance with the settlement, Columbia issued the refund during the May 2016 billing cycle. The enclosed workpapers detail the Base Rate reduction refund.

Posting and Certification of Service

Pursuant to Sections 154.2(d), 154.7(b), 154.207, and 154.208(b) of the Commission's regulations, a copy of this tariff filing is being served to all of Columbia's existing customers and affected state commissions. A copy of this filing is also available for public inspection during regular business hours in a convenient form and place at Columbia's offices at 5151 San Felipe, Suite 2400, Houston, Texas, 77056.

Service on Columbia

It is requested that a copy of all communications, correspondence and pleadings with respect to this filing be sent to:

*James R. Downs, Vice President, Rates & Regulatory Affairs
Sorana Linder, Director, Rates & Regulatory Affairs
Columbia Gas Transmission, LLC
5151 San Felipe, Suite 2400
Houston, Texas 77056
Phone: (713) 386-3759
Email: jdowns@cpg.com
slinder@cpg.com

*William A. Sala, Jr., Senior Counsel
Columbia Gas Transmission, LLC
5151 San Felipe, Suite 2400
Houston, TX 77056
Phone: (713) 386-3743
Email: tsala@cpg.com

*Persons designated for official service pursuant to Rule 2010.

Conclusion

Pursuant to Section 385.2005 and Section 385.2011(c)(5) of the Commission's regulations, the undersigned certifies that: (1) he has read the filing and knows its contents; (2) the contents are true to the best of his knowledge and belief; and (3) the undersigned possesses full power and authority to sign the filing.

[4] Pursuant to Section 11.3 of the Settlement, the Commission's order becomes a "Final Order" either by issuance of a Commission order on rehearing approving the Stipulation, or, if no rehearing request is filed, 31 days after the issuance of the Commission order approving the Stipulation. No rehearing requests were filed on the Settlement; therefore, the Commission's order became a Final Order on April 17, 2016.

Respectfully submitted,

James R. Downs

James R. Downs
Vice President, Rates and Regulatory Affairs

Enclosures

APPENDIX A

Line No.	Shipper	Contract	Rate Schedule	Flow Date	Dth	Billed Rate	Mod II Rate	Rate Change	Refund
471	COBRA PETROLEUM PRODUCTION CORPORATION	79745	FTS	2/1/2016	460	4.94	4.77	0.17	79.58
472	COBRA PETROLEUM PRODUCTION CORPORATION	79745	FTS	3/1/2016	460	4.94	4.77	0.17	79.58
473	COBRA PETROLEUM PRODUCTION CORPORATION	79745	FTS	4/1/2016	460	4.94	4.77	0.17	79.58
474	COBRA PETROLEUM PRODUCTION CORPORATION	83648	FTS	1/1/2016	350	4.94	4.77	0.17	60.55
475	COBRA PETROLEUM PRODUCTION CORPORATION	83648	FTS	2/1/2016	350	4.94	4.77	0.17	60.55
476	COBRA PETROLEUM PRODUCTION CORPORATION	83648	FTS	3/1/2016	350	4.94	4.77	0.17	60.55
477	COBRA PETROLEUM PRODUCTION CORPORATION	83648	FTS	4/1/2016	350	4.94	4.77	0.17	60.55
478	COLONIAL ENERGY INC.	168462	FTS	1/1/2016	5,000	4.94	4.77	0.17	865.00
479	COLONIAL ENERGY INC.	168462	FTS	2/1/2016	5,000	4.94	4.77	0.17	865.00
480	COLONIAL ENERGY INC.	168462	FTS	3/1/2016	5,000	4.94	4.77	0.17	865.00
481	COLUMBIA GAS OF KENTUCKY, INC	81527	FTS	1/1/2016	20,014	4.94	4.77	0.17	3,462.43
482	COLUMBIA GAS OF KENTUCKY, INC	81527	FTS	2/1/2016	20,014	4.94	4.77	0.17	3,462.42
483	COLUMBIA GAS OF KENTUCKY, INC	81527	FTS	3/1/2016	20,014	4.94	4.77	0.17	3,462.43
484	COLUMBIA GAS OF KENTUCKY, INC	81527	FTS	4/1/2016	20,014	4.94	4.77	0.17	3,462.41
485	COLUMBIA GAS OF MARYLAND, INC.	50672	SST	1/1/2016	1,177	4.77	4.60	0.17	203.61
486	COLUMBIA GAS OF MARYLAND, INC.	50672	SST	2/1/2016	1,177	4.77	4.60	0.17	203.62
487	COLUMBIA GAS OF MARYLAND, INC.	50672	SST	3/1/2016	1,177	4.77	4.60	0.17	203.62
488	COLUMBIA GAS OF MARYLAND, INC.	50672	SST	4/1/2016	589	4.77	4.60	0.17	101.89
489	COLUMBIA GAS OF MARYLAND, INC.	80025	FTS	1/1/2016	15,012	4.94	4.77	0.17	2,597.07
490	COLUMBIA GAS OF MARYLAND, INC.	80025	FTS	2/1/2016	15,012	4.94	4.77	0.17	2,597.08
491	COLUMBIA GAS OF MARYLAND, INC.	80025	FTS	3/1/2016	15,012	4.94	4.77	0.17	2,597.07
492	COLUMBIA GAS OF MARYLAND, INC.	80025	FTS	4/1/2016	15,012	4.94	4.77	0.17	2,597.08
493	COLUMBIA GAS OF MARYLAND, INC.	82247	SST	1/1/2016	32,521	4.77	4.60	0.17	5,626.14
494	COLUMBIA GAS OF MARYLAND, INC.	82247	SST	2/1/2016	32,521	4.77	4.60	0.17	5,626.13
495	COLUMBIA GAS OF MARYLAND, INC.	82247	SST	3/1/2016	32,521	4.77	4.60	0.17	5,626.13
496	COLUMBIA GAS OF MARYLAND, INC.	82247	SST	4/1/2016	16,261	4.77	4.60	0.17	2,813.16
497	COLUMBIA GAS OF MARYLAND, INC.	168668	FTS	1/1/2016	1,666	4.94	4.77	0.17	288.22
498	COLUMBIA GAS OF MARYLAND, INC.	168668	FTS	2/1/2016	1,666	4.94	4.77	0.17	288.21
499	COLUMBIA GAS OF MARYLAND, INC.	168668	FTS	3/1/2016	1,666	4.94	4.77	0.17	288.21
500	COLUMBIA GAS OF MARYLAND, INC.	168668	FTS	4/1/2016	1,666	4.94	4.77	0.17	288.21
501	COLUMBIA GAS OF MARYLAND, INC.	168669	FTS	1/1/2016	3,334	4.94	4.77	0.17	576.78
502	COLUMBIA GAS OF MARYLAND, INC.	168669	FTS	2/1/2016	3,334	4.94	4.77	0.17	576.79
503	COLUMBIA GAS OF MARYLAND, INC.	168669	FTS	3/1/2016	3,334	4.94	4.77	0.17	576.79
504	COLUMBIA GAS OF MARYLAND, INC.	168669	FTS	4/1/2016	3,334	4.94	4.77	0.17	576.78
505	COLUMBIA GAS OF OHIO, INC.	3044	SST	1/1/2016	1,445,102	4.77	4.60	0.17	250,002.64
506	COLUMBIA GAS OF OHIO, INC.	3044	SST	2/1/2016	1,445,102	4.77	4.60	0.17	250,002.62
507	COLUMBIA GAS OF OHIO, INC.	3044	SST	3/1/2016	1,445,102	4.77	4.60	0.17	250,002.63
508	COLUMBIA GAS OF OHIO, INC.	3044	SST	4/1/2016	722,551	4.77	4.60	0.17	125,001.33
509	COLUMBIA GAS OF OHIO, INC.	80152	FTS	1/1/2016	238,186	4.94	4.77	0.17	41,206.18
510	COLUMBIA GAS OF OHIO, INC.	80152	FTS	2/1/2016	238,186	4.94	4.77	0.17	41,206.18
511	COLUMBIA GAS OF OHIO, INC.	80152	FTS	3/1/2016	238,186	4.94	4.77	0.17	41,206.18
512	COLUMBIA GAS OF OHIO, INC.	80152	FTS	4/1/2016	188,186	4.94	4.77	0.17	32,556.19
513	COLUMBIA GAS OF OHIO, INC.	82544	FTS	1/1/2016	38,974	4.94	4.77	0.17	6,742.51
514	COLUMBIA GAS OF OHIO, INC.	82544	FTS	2/1/2016	38,974	4.94	4.77	0.17	6,742.51
515	COLUMBIA GAS OF OHIO, INC.	82544	FTS	3/1/2016	38,974	4.94	4.77	0.17	6,742.51
516	COLUMBIA GAS OF OHIO, INC.	82544	FTS	4/1/2016	38,974	4.94	4.77	0.17	6,742.51
517	COLUMBIA GAS OF OHIO, INC.	82545	FTS	1/1/2016	29,231	4.94	4.77	0.17	5,056.96

FERC rendition of the electronically filed tariff records in Docket No. RP16-00864-000
Filing Data:
CID: C000306
Filing Title: Modernization II Settlement Refund Report - RP16-314
Company Filing Identifier: 624
Type of Filing Code: 670
Associated Filing Identifier: 620
Tariff Title: Columbia Gas Tariffs
Tariff ID: 3
Payment Confirmation:
Suspension Motion:

Tariff Record Data:

Document Content(s)

PIPELINE COMPANY TARIFF SHEETS

Currently Effective Rates
Applicable to Rate Schedule SST
Rate Per Dth

		Base Tariff Rate 1/ 2/	TCRA Rates	EPCA Rates	OTRA Rates	CCRM Rates	Total Effective Rate 2/	Daily Rate 2/
Rate Schedule SST								
Reservation Charge 3/4/	$	4.601	0.232	0.070	0.073	1.044	6.020	0.1979
Commodity								
Maximum	¢	1.02	-0.07	0.84	0.00	0.00	1.79	1.79
Minimum	¢	1.02	-0.07	0.84	0.00	0.00	1.79	1.79
Overrun 4/								
Maximum	¢	16.15	0.69	1.07	0.24	3.43	21.58	21.58
Minimum	¢	1.02	-0.07	0.84	0.00	0.00	1.79	1.79

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/ Excludes the Annual Charge Adjustment (ACA) Surcharge. An ACA Commodity surcharge per Dth shall be assessed where applicable pursuant to Section 154.402 of the Commission's Regulations and in accordance with Section 34 of the GTC of Transporter's FERC Gas Tariff. The ACA unit charge authorized for each fiscal year (commencing October 1) by the Commission and posted on its website (http://www.ferc.gov) is incorporated herein by reference.

3/ Minimum reservation charge is $0.00.

4/ Shippers utilizing the Eastern Market Expansion (EME) facilities for Rate Schedule SST service will pay 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 a total overrun rate of 58.97 cents. The applicable EME demand charge and EME overrun charge can be added to the applicable surcharges above to calculate the EME Total Effective Rates.

Currently Effective Rates
Applicable to Rate Schedule FTS
Rate Per Dth

		Base Tariff Rate 1/ 2/	TCRA Rates	EPCA Rates	OTRA Rates	CCRM Rates	Total Effective Rate 2/	Daily Rate 2/
Rate Schedule FTS								
Reservation Charge 3/	$	4.771	0.232	0.070	0.073	1.044	6.190	0.2035
Commodity								
Maximum	¢	1.04	-0.07	0.84	0.00	0.00	1.81	1.81
Minimum	¢	1.04	-0.07	0.84	0.00	0.00	1.81	1.81
Overrun								
Maximum	¢	16.73	0.69	1.07	0.24	3.43	22.16	22.16
Minimum	¢	1.04	-0.07	0.84	0.00	0.00	1.81	1.81

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/ Excludes the Annual Charge Adjustment (ACA) Surcharge. An ACA Commodity surcharge per Dth shall be assessed where applicable pursuant to Section 154.402 of the Commission's Regulations and in accordance with Section 34 of the GTC of Transporter's FERC Gas Tariff. The ACA unit charge authorized for each fiscal year (commencing October 1) by the Commission and posted on its website (http://www.ferc.gov) is incorporated herein by reference.

3/ Minimum reservation charge is $0.00.

Currently Effective Rates
Applicable to Rate Schedule FSS
Rate Per Dth

		Base Tariff Rate 1/	Transportation Cost Rate Adjustment		Electric Power Costs Adjustment		Annual Charge Adjustment 2/	Total Effective Rate	Daily Rate
			Current	Surcharge	Current	Surcharge			
Rate Schedule FSS									
Reservation Charge 3/	$	1.501	-	-	-	-	-	1.501	0.0493
Capacity 3/	¢	2.88	-	-	-	-	-	2.88	2.88
Injection	¢	1.53	-	-	-	-	-	1.53	1.53
Withdrawal	¢	1.53	-	-	-	-	-	1.53	1.53
Overrun 3/	¢	10.87	-	-	-	-	-	10.87	10.87

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/ Shippers utilizing the Eastern Market Expansion (EME) facilities for FSS service will pay a total FSS MDSQ reservation charge of $4.130 and 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 a total FSS overrun rate of 23.44 cents. The additional EME demand charges and EME overrun charges can be added to the applicable surcharges above to develop the EME Total Effective Rate.

RETAINAGE PERCENTAGES

Transportation Retainage	2.042%
Gathering Retainage	3.500%
Storage Gas Loss Retainage	0.150%
Ohio Storage Gas Lost Retainage	0.250%
Columbia Processing Retainage 1/	0.000%

1/ The Columbia Processing Retainage shall be assessed separately from the processing retainage applicable to third party processing plants set forth in Section 25.3 (f) of the General Terms and Conditions.

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

Rate Schedule FTS-1	Base Rate (1) 1/	Total Effective Rate (2) 1/	Daily Rate (3) 1/
Market Zone			
Reservation Charge			
Maximum	4.2917	4.2917	0.1411
Minimum	0.000	0.000	0.000
Commodity			
Maximum	0.0109	0.0109	0.0109
Minimum	0.0109	0.0109	0.0109
Overrun			
Maximum	0.1520	0.1520	0.1520
Minimum	0.0109	0.0109	0.0109

1/ Excludes the Annual Charge Adjustment (ACA) Surcharge. An ACA Commodity surcharge per Dth shall be assessed where applicable pursuant to Section 154.402 of the Commission's Regulations and in accordance with Section 31 of the GTC of Transporter's FERC Gas Tariff. The ACA unit charge authorized for each fiscal year (commencing October 1) by the Commission and posted on its website (http://www.ferc.gov) is incorporated herein by reference.

Currently Effective Rates
Applicable to Rate Schedule FTS
Rate per Dth

	Base Tariff Rate 2/	Total Effective Rate 2/	Daily Rate 2/
Rate Schedule FTS			
Reservation Charge 1/	$ 0.509	0.509	0.0167
Commodity			
Maximum	¢ 0.00	0.00	0.00
Minimum	¢ 0.00	0.00	0.00
Overrun	¢ 1.67	1.67	1.67

1/ Minimum reservation charge is $0.00.
2/ Excludes the Annual Charge Adjustment (ACA) Surcharge. An ACA Commodity surcharge per Dth shall be assessed where applicable pursuant to Section 154.402 of the Commission's Regulations and in accordance with Section 31 of the GTC of Transporter's FERC Gas Tariff. The ACA unit charge authorized for each fiscal year (commencing October 1) by the Commission and posted on its website (http://www.ferc.gov) is incorporated herein by reference.

RETAINAGE PERCENTAGE

Transportation Retainage	0.663%

Execution Copy

THIRD PARTY PAYMENT AGREEMENT

THIS THIRD PARTY PAYMENT AGREEMENT (this "Agreement") dated as of October 1, 2015 (the "Effective Date") by and COLUMBIA GAS TRANSMISSION, LLC, f/k/a Columbia Gas Transmission Corporation ("Owner-Operator"), and COLUMBIA GAS OF KENTUCKY, INC. ("CKY") under the following circumstances (CKY and Owner-Operator are individually referred to herein as a "Party" and collectively as the "Parties"):

A. CKY owns all of the outstanding voting securities of Central Kentucky Transmission Company, a Delaware corporation ("Co-Owner"). Co-Owner is engaged in the interstate transportation of gas and owns a 25 percent undivided interest in Owner-Operator's line KA-1 North interstate transmission pipeline and appurtenant facilities (the "Pipeline"). The Pipeline is Co-Owner's only asset subject to the jurisdiction of the Federal Energy Regulatory Commission (the "FERC"). CKY holds all of the shipping capacity on Co-Owner's portion of the Pipeline. The remaining 75 percent undivided interest in the Pipeline is owned by Owner-Operator.

B. Owner-Operator and Co-Owner are parties to that certain Operating Agreement dated as of March 18, 2005, as amended by that certain Amendment to Operating Agreement dated as of April 25, 2006 and by that certain Second Amendment to Operating Agreement dated July 1, 2015 (the "Existing Operating Agreement") wherein Owner-Operator and Co-Owner have agreed to the terms and conditions regarding the provision of Operational Services and Commercial Services by Owner-Operator to Co-Owner. Capitalized terms used and not otherwise defined herein have the respective meanings given to such terms in the Operating Agreement.

C. Pursuant to the Existing Operating Agreement, Co-Owner pays Owner-Operator a Flat Monthly Charge for Operational Services equal to $7,300, and a Flat Monthly Charge for Commercial Services equal to $8,333. $6,000 per month of the Flat Monthly Charge for Operational Services is recovered by Co-Owner through Co-Owner's tariff rates for shipping service on file with the FERC. The remaining $1,300 of the Flat Monthly Charge for Operational Services and the $8,333 Flat Monthly Charge for Commercial Services (collectively, such amount being referred to herein as the "Incremental Monthly Charges") is not being recovered by Co-Owner through rates or otherwise.

D. To avoid the expense and delay in time that would be required for Co-Owner to file an application with FERC to increase Co-Owner's tariff rates so that Co-Owner could recover through rates the Incremental Monthly Charge, which would be paid entirely by CKY, CKY and Co-Owner desire instead to have CKY pay Owner-Operator monthly the amount of the Incremental Monthly Charge.

E. Contemporaneously with the execution and delivery of this Agreement, Co-Owner and Owner-Operator are executing and delivering that certain Third Amendment to Operating Agreement dated as of the date hereof (the "Third Amendment") whereby Owner-Operator and Co-Owner are amending the Existing Operating Agreement to provide that Owner-Operator will invoice CKY monthly for the Incremental Monthly Charge.

NOW THEREFORE, in consideration of the mutual covenants and agreements contained herein, and intending to be legally bound hereby, the Parties agree as follows:

1. Incorporation of Recitals; Definitions. The Recitals set forth hereinabove are incorporated into this Agreement as if restated and set forth in full. Capitalized terms used and not otherwise defined herein have the respective meanings given such terms in the Existing Operating Agreement, as amended by the Third Amendment (the "Operating Agreement"). As used herein, the term "Section" refers to a Section of this Agreement.

2. Invoicing by Owner-Operator. Unless and until Owner-Operator receives written notice from Co-Operator and CKY to invoice Co-Owner and CKY in a different manner, Owner-Operator shall invoice CKY each month for (a) $1,300 of the Flat Monthly Charge for Operational Services and (b) all of the $8,333 of the Flat Monthly Charge for the Commercial Services. Owner-Operator agrees to accept payment of all amounts from CKY made on Co-Owner's behalf. Notwithstanding anything herein to the contrary, the Parties agree that Co-Owner shall at all times during the term of this Agreement remain primarily liable for the Flat Monthly Charges under the Operating Agreement, including, without limitation, the Incremental Monthly Charges that shall be invoiced to CKY under this Agreement. In the event CKY fails to make any payment in whole or in part of any Incremental Monthly Charge that is properly due and payable under the Operating Agreement, CKY agrees that Owner-Operator shall have the right to seek collection of all such amounts that become properly due and payable under the Operating Agreement from either CKY or Co-Owner.

2. Payment by CKY. During the Term, CKY agrees to pay timely all invoices for Incremental Monthly Charges due and payable under the Operating Agreement, together with any interest and penalties for late payment accruing with respect to such Incremental Monthly Charges. CKY reserves the right to assert all defenses, counterclaims and offsets that Co-Owner could assert under the Amended Operating Agreement. CKY's payment obligations under this Agreement are specifically limited to payment of the Incremental Monthly Charges as and when the same become due under the Operating Agreement and CKY is not and shall not become obligated in any manner to perform any other obligations or make other payments that may become due or otherwise owed to Owner-Operator by Co-Owner or others pursuant to or arising out of the Operating Agreement. This Agreement does not constitute a guaranty or create any other instrument of suretyship.

3. Term; Termination.

a. The term of this Agreement ("Term") shall commence on the Effective Date and shall continue until the earlier of (i) termination of the Operating Agreement, or (ii) termination pursuant to Section 3.b. Termination is not an election of remedies for any breach or default of a Party's obligations under this Agreement, and shall discharge only those obligations that have not accrued as of the effective date of termination. Any right or duty of a Party based on either the performance or breach of this Agreement prior to the effective date of termination shall survive the Term.

b. This Agreement may be terminated:

i. by CKY, for any reason or for convenience, upon thirty (30) days prior written notice to Owner-Operator; or

ii. by Owner-Operator, upon fifteen (15) days prior written notice to CKY, in the event CKY fails to make any payment required to made under this Agreement when due and such failure continues for a period of forty-five (45) days; or

iii. by either party, upon written notice to the other, in the event such other Party files a voluntary petition in bankruptcy or reorganization or fails to have such a petition filed against it dismissed within thirty (30) days or admits in writing its insolvency or inability to pay its liabilities as they come due, or assigns its assets for the benefit of creditors, or suffers a receiver to be appointed for its assets or suspends its business;

iv. immediately, without the requirement of notice by or to any Party, in the event that Co-Owner files a voluntary petition in bankruptcy or reorganization or fails to have such a petition filed against it dismissed within thirty (30) days or admits in writing its insolvency or inability to pay its liabilities as they come due, or assigns its assets for the benefit of creditors, or suffers a receiver to be appointed for its assets or suspends its business.

4. Notices. All notices required or permitted to be made pursuant to this Agreement shall be in writing and delivered by U.S. Mail, email, in person or by a nationally recognized overnight courier, to the Parties at the following respective addresses, or such other address as a Party may specify by written notice duly given pursuant to this Section:

If to CKY:

Columbia Gas of Kentucky, Inc.
2001 Mercer Road
Lexington, KY 40511
Attention: President
Phone: 859-288-0275

with a copy to:

Columbia Gas of Kentucky, Inc.
2001 Mercer Road
Lexington, KY 40511
Attention: Director of Regulatory
Phone: 859-288-0242

If to Owner-Operator:

Columbia Gas Transmission, LLC
5151 San Felipe
Suite 2400
Houston, TX 77056
Attention: Sr. Vice President, Commercial Operations
Phone: 713-386-3488

Notices shall be deemed received three business days after being deposited into the U.S. mail, or at the time transmitted by email, if such transmission is telephonically or digitally confirmed as having been received by the recipient, or when actually received if delivered by hand delivery or overnight courier.

5. Third-Party Beneficiaries. Co-Owner is expressly made a third-party beneficiary to this Agreement. There are no other third-party beneficiaries to this Agreement.

6. Counterparts; Entire Agreement. This Agreement may be executed in counterparts, each of which shall be deemed an original instrument, but all such counterparts together shall constitute one and the same agreement. This Agreement constitutes the entire agreement among the Parties pertaining to the subject matter hereof, and supersedes all prior agreements, understandings, negotiations and discussions, whether oral or written, of the Parties pertaining to the subject matter hereof.

7. Binding Agreement. Each Party hereby represents and warrants that this Agreement is a legal, valid and binding obligation of such Party and is enforceable against such Party in accordance with its terms.

8. Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of the Parties and their respective successors and assigns.

9. Rules of Construction; No Waiver. Section headings and titles used in this Agreement are for convenience of reference only and in no way define, limit, extend or describe the scope or intent of any provisions of this Agreement. If any section, subsection, term or provision of this Agreement or the application thereof to any party or circumstance shall, to any extent, be invalid or unenforceable, the remainder of such section, subsection, term or provision and the application of the same to parties or circumstances other than those to which it is held invalid or unenforceable shall not be affected thereby, and shall be valid and enforceable to the fullest extent permitted by law. Amendments, modifications and waivers to this Agreement shall be made only by written instrument signed by both Parties. Any waiver by a party of any provision or condition of this Agreement shall not be construed or deemed to be a waiver of any other provision or condition of this Agreement, nor a waiver of a subsequent breach of the same provision or condition, whether such breach is of the same or a different nature as the prior breach.

10. Governing Law. This Agreement shall be construed and enforced in accordance with the internal laws of the State of Kentucky, without regard to any principles relating to conflicts of law that may direct the application of the laws of another jurisdiction.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed and delivered by their duly authorized officers as of the Effective Date.

COLUMBIA GAS TRANSMISSION, LLC

By: Stanley G. Chapman
Name: Stanley G. Chapman, III
Its: Executive Vice President and Chief Commercial Officer

COLUMBIA GAS OF KENTUCKY, INC.

By: Herbert A. Miller
Name: Herbert A. Miller
Its: President

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base
Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.2668	$0.2546	$0.3030
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.2269	$0.2313	$0.2641
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0734	$0.1178	$0.1305
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0982	$0.1358	$0.1482
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0454	$0.0642	$0.1041
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0639	$0.0633	$0.0787
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0984	$0.0533	$0.0324

Minimum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.0250	$0.0284	$0.0346
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.0210	$0.0256	$0.0300
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0056	$0.0100	$0.0143
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0081	$0.0118	$0.0163
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0028	$0.0046	$0.0092
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0046	$0.0046	$0.0066
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0086	$0.0041	$0.0020

Maximum
Commodity Rates 1/, 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0039		$0.0122	$0.0184	$0.0226	$0.2675	$0.2553	$0.3037
L		$0.0019						
1	$0.0049		$0.0088	$0.0154	$0.0186	$0.2276	$0.2320	$0.2648
2	$0.0174		$0.0094	$0.0019	$0.0035	$0.0741	$0.1185	$0.1312
3	$0.0214		$0.0176	$0.0033	$0.0009	$0.0989	$0.1365	$0.1489
4	$0.0257		$0.0212	$0.0094	$0.0112	$0.0461	$0.0649	$0.1048
5	$0.0291		$0.0263	$0.0107	$0.0125	$0.0646	$0.0640	$0.0794
6	$0.0353		$0.0307	$0.0150	$0.0170	$0.0991	$0.0540	$0.0331

Notes:

1/ Rates stated above exclude the ACA Surcharge as revised annually and posted on the FERC website at http://www.ferc.gov on the Annual Charges page of the Natural Gas section. The ACA Surcharge is incorporated by reference into Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Article XXIV of the General Terms and Conditions.
2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0007.

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	15.00			15.00	
Delivery Charge per Mcf	2.2666	1.4194	1.1080	4.7940	I
RATE SCHEDULE GSO					
Commercial or Industrial					
Customer Charge per billing period	37.50			37.50	
Delivery Charge per Mcf -					
First 50 Mcf or less per billing period	2.2666	1.4194	1.1080	4.7940	I
Next 350 Mcf per billing period	1.7520	1.4194	1.1080	4.2794	I
Next 600 Mcf per billing period	1.6659	1.4194	1.1080	4.1933	I
Over 1,000 Mcf per billing period	1.5164	1.4194	1.1080	4.0438	I
RATE SCHEDULE IS					
Customer Charge per billing period	1,007.05			1007.05	
Delivery Charge per Mcf					
First 30,000 Mcf per billing period	0.5443		1.1080 [2/]	1.6523	I
Over 30,000 Mcf per billing period	0.2890		1.1080 [2/]	1.3970	I
Firm Service Demand Charge					
Demand Charge times Daily Firm					
Volume (Mcf) in Customer Service Agreement		6.8133		6.8133	I
RATE SCHEDULE IUS					
Customer Charge per billing period	477.00			477.00	
Delivery Charge per Mcf					
For All Volumes Delivered	0.8150	1.4194	1.1080	3.3424	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 $4.5164 per Mcf only for those months of the prior twelve months during which they were served under Rate Schedule SVGTS.

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

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TITLE 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		6.8133		6.8133	I
Standby Service Commodity Charge per Mcf			1.1080	1.1080	I
RATE SCHEDULE DS					
Administrative Charge per account per billing period				55.90	
Customer Charge per billing period [2/]				1007.05	
Customer Charge per billing period (GDS only)				37.50	
Customer Charge per billing period (IUDS only)				477.00	
Delivery Charge per Mcf[2/]					
First 30,000 Mcf	0.5443			0.5443	
Over 30,000 Mcf	0.2890			0.2890	
– Grandfathered Delivery Service					
First 50 Mcf or less per billing period				2.2666	
Next 350 Mcf per billing period				1.7520	
Next 600 Mcf per billing period				1.6659	
All Over 1,000 Mcf per billing period				1.5164	
– Intrastate Utility Delivery Service					
All Volumes per billing period				0. 8150	
Banking and Balancing Service					
Rate per Mcf		0.0209		0.0209	
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		0.0209		0.0209	

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.

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CURRENTLY EFFECTIVE BILLING RATES
(Continued)

<u>**RATE SCHEDULE SVGTS**</u>		<u>**Base Rate Charge**</u> $	
<u>General Service Residential (SGVTS GSR)</u>			
Customer Charge per billing period		15.00	
Delivery Charge per Mcf		2.2666	
<u>General Service Other - Commercial or Industrial (SVGTS GSO)</u>			
Customer Charge per billing period		37.50	
Delivery Charge per Mcf -			
First 50 Mcf or less per billing period		2.2666	
Next 350 Mcf per billing period		1.7520	
Next 600 Mcf per billing period		1.6659	
Over 1,000 Mcf per billing period		1.5164	
<u>Intrastate Utility Service</u>			
Customer Charge per billing period		477.00	
Delivery Charge per Mcf		$ 0.8150	
	<u>**Billing Rate**</u>		
<u>Actual Gas Cost Adjustment [1/]</u>			
For all volumes per billing period per Mcf	($1.9357)		R
<u>**RATE SCHEDULE SVAS**</u>			
Balancing Charge – per Mcf	$1.2283		R

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.

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