Columbia Gas of Kentucky
A NiSource Company
P.O. Box 14241
2001 Mercer Road
Lexingtion, KY 40512-4241

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JAN 31 2017

PUBLIC SERVICE
COMMISSION

January 31, 2017

Ms. Talina Mathews
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. 2017 – 00057

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 March quarterly Gas Cost Adjustment ("GCA").

Columbia proposes to increase its current rates to tariff sales customers by $1.2995 per Mcf effective with its March 2017 billing cycle on March 1, 2017. The increase is composed of an increase of $0.4386 per Mcf in the Average Commodity Cost of Gas, a decrease of ($0.0039) per Mcf in the Average Demand Cost of Gas, an increase of $0.4702 per Mcf in the Balancing Adjustment, a decrease of ($0.0010) in the Supplier Refund Adjustment, and an increase of $0.3956 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. 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

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JAN 31 2017

PUBLIC SERVICE
COMMISSION

BEFORE THE
PUBLIC SERVICE COMMISSION
OF KENTUCKY

COLUMBIA GAS OF KENTUCKY, INC.

CASE 2017 – 00057

GAS COST ADJUSTMENT AND REVISED RATES OF
COLUMBIA GAS OF KENTUCKY, INC. PROPOSED TO BECOME
EFFECTIVE MARCH 2017 BILLINGS

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

Line No.		December-16 CURRENT	March-17 PROPOSED	DIFFERENCE
1	Commodity Cost of Gas	$3.5118	$3.9504	$0.4386
2	Demand Cost of Gas	$1.4745	$1.4706	($0.0039)
3	Total: Expected Gas Cost (EGC)	$4.9863	$5.4210	$0.4347
4	SAS Refund Adjustment	$0.0000	$0.0000	$0.0000
5	Balancing Adjustment	($0.4702)	$0.0000	$0.4702
6	Supplier Refund Adjustment	($0.0010)	($0.0020)	($0.0010)
7	Actual Cost Adjustment	($0.1587)	$0.2369	$0.3956
8	Performance Based Rate Adjustment	$0.3668	$0.3668	$0.0000
9	Cost of Gas to Tariff Customers (GCA)	$4.7232	$6.0227	$1.2995
10	Transportation TOP Refund Adjustment	$0.0000	$0.0000	$0.0000
11	Banking and Balancing Service	$0.0209	$0.0215	$0.0006
12	Rate Schedule FI and GSO			
13	Customer Demand Charge	$6.8133	$7.0290	$0.2157

Columbia Gas of Kentucky, Inc.
Gas Cost Adjustment Clause
Gas Cost Recovery Rate
Mar - May 17

Line No.	Description			Amount	Expires
1	Expected Gas Cost (EGC)	Schedule No. 1		$5.4210	05-31-17
2	Actual Cost Adjustment (ACA)	Schedule No. 2		$0.2369	Various
3	Supplier Refund Adjustment (RA)	Schedule No. 4		($0.0020)	Various
4	Balancing Adjustment (BA)	Schedule No. 3		$0.0000	05-31-17
5	Performance Based Rate Adjustment (PBRA)	Schedule No. 6	Case No. 2016-00166	$0.3668	05-31-17
6	Gas Cost Adjustment				
7	Mar - May 17			$6.0227	
8	Expected Demand Cost (EDC) per Mcf				
9	(Applicable to Rate Schedule IS/SS and GSO)	Schedule No. 1, Sheet 4		$7.0290	

DATE FILED: January 31, 2017 **BY: J. M. Cooper**

Columbia Gas of Kentucky, Inc.
Expected Gas Cost for Sales Customers
Mar - May 17

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				(1,265,000)		$0.0153	$19,355
2	Injection				2,139,000		$0.0153	$32,727
3	Withdrawals: gas cost includes pipeline fuel and commodity charges				1,251,000		$3.2676	$4,087,768
	Total							
4	Volume	= 3			1,251,000			
5	Cost	sum(1:3)						$4,139,850
6	Summary	4 or 5			1,251,000			$4,139,850
	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		1,241,000			$4,269,040
8	Appalachian Supplies		Sch.1, Sht. 6, Ln. 4		91,000			$375,000
9	Less Fuel Retention By Interstate Pipelines		Sch. 1,Sheet 7, Lines 21, 22		(94,000)			($327,147)
10	Total	7 + 8 + 9			1,238,000			$4,316,893
	Total Supply							
11	At City-Gate		Line 6 + 10		2,489,000			$8,456,743
	Lost and Unaccounted For							
12	Factor				-1.0%			
13	Volume		Line 11 * 12		(24,890)			
14	At Customer Meter		Line 11 + 13	2,238,065	2,464,110			
15	Less: Right-of-Way Contract Volume			893				
16	**Sales Volume**		Line 14-15	2,237,172				
	Unit Costs $/MCF							
	Commodity Cost							
17	Excluding Cost of Pipeline Retention		Line 11 / Line 16			$3.7801		
18	Annualized Unit Cost of Retention		Sch. 1,Sheet 7, Line 24			$0.1342		
19	Including Cost of Pipeline Retention		Line 17 + 18			$3.9143		
20	Uncollectible Ratio		CN 2016-00162			0.00923329		
21	Gas Cost Uncollectible Charge		Line 19 * Line 20			$0.0361		
22	Total Commodity Cost		line 19 + line 21			$3.9504		
23	Demand Cost		Sch.1, Sht. 2, Line 10			$1.4706		
24	Total Expected Gas Cost (EGC)		Line 22 + 23			$5.4210		

A/ BTU Factor = 1.1010 Dth/MCF

Columbia Gas of Kentucky, Inc.
GCA Unit Demand Cost
Mar - May 17

Schedule No. 1
Sheet 2

Line No.	Description		Reference		
1	Expected Demand Cost: Annual Mar - Feb 2018		Sch. No.1, Sheet 3, Ln. 11	$20,600,090	
2	Less Rate Schedule IS/SS and GSO Customer Demand Charge Recovery		Sch. No.1, Sheet 4, Ln. 10	-$228,330	
3	Less Storage Service Recovery from Delivery Service Customers			-$189,933	
4	Net Demand Cost Applicable	1 + 2 + 3		$20,181,827	
	Projected Annual Demand: Sales + Choice				
	At city-gate				
	In Dth			15,266,000	Dth
	Heat content			1.1010	Dth/MCF
5	In MCF			13,865,577	MCF
	Lost and Unaccounted - For				
6	Factor			1.0%	
7	Volume	5 * 6		138,656	MCF
8	Right of way Volumes			3,218	
9	At Customer Meter	5 - 7- 8		13,723,703	MCF
10	Unit Demand Cost (4/ 9)	To Sheet 1, line 23		$1.4706	per MCF

Columbia Gas of Kentucky, Inc.
Annual Demand Cost of Interstate Pipeline Capacity
Mar - Feb 2018

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	$6.4280	12	$1,543,800
6	Subtotal	sum(1:5)				$17,734,889
	Columbia Gulf Transmission Company					
7	FTS - 1 (Mainline)		28,991	$4.1700	12	$1,450,710
	Tennessee Gas					
8	Firm Transportation		20,506	$4.5835	12	$1,127,871
	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					$20,600,090

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
Mar - Feb 2018

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)						$20,600,090
	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				1.101	Dth/MCF	
7	Total Capacity - Annualized	Line 5/ Line 6			2,930,725	Mcf	
8	Monthly Unit Expected Demand Cost (EDC) of Daily Capacity Applicable to Rate Schedules IS/SS and GSO Line 1 / Line 7				$7.0290	/Mcf	
9	Firm Volumes of IS/SS and GSO Customers		2,707	12	32,484	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		$228,330

Columbia Gas of Kentucky, Inc.
Non-Appalachian Supply: Volume and Cost
Mar - May 17

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	Mar-17	186,000	$660,000		0	186,000	
2	Apr-17	1,513,000	$5,151,000		(815,000)	698,000	
3	May-17	1,667,000	$5,754,000		(1,310,000)	357,000	
4	Total 1+2+3	3,366,000	$11,565,000	$3.44	(2,125,000)	1,241,000	$4,269,040

A/ Gross, before retention.

Columbia Gas of Kentucky, Inc.
Appalachian Supply: Volume and Cost
Mar - May 17

Schedule No. 1
Sheet 6

Line No.	Month		Dth (2)	Cost (3)
1	Mar-17		40,000	$169,000
2	Apr-17		29,000	$120,000
3	May-17		22,000	$86,000
4	Total	1 + 2 + 3	91,000	$375,000

Columbia Gas of Kentucky, Inc.
Annualized Unit Charge for Gas Retained by Upstream Pipelines
Mar - May 17

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	Mar - May 17	Jun - Aug 17	Sep - Nov 17	Dec - Feb 18	Annual Mar - Feb 2018
	Gas purchased by CKY for the remaining sales customers							
1	Volume		Dth	3,457,000	4,489,000	2,514,000	1,312,000	11,772,000
2	Commodity Cost Including Transportation			$11,940,000	$15,613,000	$8,610,000	$4,807,000	$40,970,000
3	Unit cost		$/Dth					$3.4803
	Consumption by the remaining sales customers							
11	At city gate		Dth	2,490,000	569,000	1,889,000	6,497,000	11,445,000
12	Lost and unaccounted for portion			1.00%	1.00%	1.00%	1.00%	
	At customer meters							
13	In Dth	(100% - 12) * 11	Dth	2,465,100	563,310	1,870,110	6,432,030	11,330,550
14	Heat content		Dth/MCF	1.1010	1.1010	1.1010	1.1010	
15	In MCF	13 / 14	MCF	2,238,965	511,635	1,698,556	5,841,989	10,291,145
16	Portion of annual	line 15, quarterly / annual		21.8%	5.0%	16.5%	56.8%	100.0%
	Gas retained by upstream pipelines							
21	Volume		Dth	94,000	90,000	69,000	143,000	396,000
	Cost			To Sheet 1, line 9				
22	Quarterly. Deduct from Sheet 1	3 * 21		$327,147	$313,226	$240,140	$497,682	$1,378,195
23	Allocated to quarters by consumption			$300,447	$68,910	$227,402	$782,815	$1,379,574
				To Sheet 1, line 18				
24	Annualized unit charge	23 / 15	$/MCF	$0.1342	$0.1347	$0.1339	$0.1340	$0.1341

COLUMBIA GAS OF KENTUCKY, INC.

Schedule No. 1

Sheet 8

DETERMINATION OF THE BANKING AND BALANCING CHARGE
FOR THE PERIOD BEGINNING MARCH 2017

Line No.	Description	Dth	Detail	Amount For Transportation Customers
1	Total Storage Capacity. Sheet 3, line 2	11,264,911		
2	Net Transportation Volume	9,709,718		
3	Contract Tolerance Level @ 5%	485,486		
4	Percent of Annual Storage Applicable			
5	to Transportation Customers		4.31%	
6	Seasonal Contract Quantity (SCQ)			
7	Rate		$0.0288	
8	SCQ Charge - Annualized		$3,893,153	
9	Amount Applicable To Transportation Customers			**$167,795**
10	FSS Injection and Withdrawal Charge			
11	Rate		0.0306	
12	Total Cost		$344,706	
13	Amount Applicable To Transportation Customers			**$14,857**
14	SST Commodity Charge			
15	Rate		0.0192	
16	Projected Annual Storage Withdrawal, Dth		8,798,000	
17	Total Cost		$168,922	
18	Amount Applicable To Transportation Customers			**$7,281**
19	Total Cost Applicable To Transportation Customers			**$189,933**
20	Total Transportation Volume - Mcf			16,754,000
21	Flex and Special Contract Transportation Volume - Mcf			(7,935,000)
22	Net Transportation Volume - Mcf	line 20 + line 21		8,819,000
23	Banking and Balancing Rate - Mcf.	Line 19 / line 22. To line 11 of the GCA Comparison		**$0.0215**

DETAIL SUPPORTING

DEMAND/COMMODITY SPLIT

COLUMBIA GAS OF KENTUCKY
CASE NO. 2017- Effective March 2017 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)	$1.4706	
Demand ACA (Schedule No. 2, Sheet 1, Case No. 2016-00166, Case No. 2016-00285, Case No. 2016-00381, & Case No. 2017-)	$0.6071	
Refund Adjustment (Schedule No. 4, Case No. 2016-00285 & Case No. 2017-)	($0.0020)	
Total Demand Rate per Mcf	$2.0757	<--- to Att. E, line 15
Commodity Component of Gas Cost Adjustment		
Commodity Cost of Gas (Schedule No. 1, Sheet 1, Line 22)	$3.9504	
Commodity ACA (Schedule No. 2, Sheet 1, Case No. 2016-00166, Case No. 2016-00285, Case No. 2016-00381, & Case No. 2017-)	($0.3702)	
Balancing Adjustment	$0.0000	
Performance Based Rate Adjustment (Schedule No. 6, Case No. 2016-00166)	$0.3668	
Total Commodity Rate per Mcf	$3.9470	
CHECK:	$2.0757	
	$3.9470	
COST OF GAS TO TARIFF CUSTOMERS (GCA)	$6.0227	
Calculation of Rate Schedule SVGTS - Actual Gas Cost Adjustment		
Commodity ACA (Schedule No. 2, Sheet 1, Case No. 2016-00166, Case No. 2016-00285, Case No. 2016-00381, & Case No. 2017-)	($0.3702)	
Balancing Adjustment	$0.0000	
Performance Based Rate Adjustment (Schedule No. 6, Case No. 2016-00166)	$0.3668	
Total Commodity Rate per Mcf	($0.0034)	

Columbia Gas of Kentucky, Inc.
CKY Choice Program
100% Load Factor Rate of Assigned FTS Capacity
Balancing Charge
Mar - May 17

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	1.893%						
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				$6.4280	12	0.4168	1.0000	$32.1503	
11	Gulf FTS-1, upstream to CKT FTS				$4.1700	12	0.5832	1.0067	$29.3781	
12	TGP FTS-A, upstream to TCO FTS				$4.5835	12	0.4168	1.0193	$23.3672	
13	Total Demand Cost of Assigned FTS, per unit								$88.4578	$97.3920
14	100% Load Factor Rate (Line 13 / 365 days)									$0.2668
	Balancing charge, paid by Choice marketers									
15	Demand Cost Recovery Factor in GCA, per Mcf per CKY Tariff Sheet No. 5									$2.0757
16	Less credit for cost of assigned capacity									($0.2668)
17	Plus storage commodity costs incurred by CKY for the Choice marketer									$0.0745
18	Balancing Charge, per Mcf sum(15:17)									$1.8834

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 NOVEMBER 30, 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	September 2016	194,750	0	194,750	$4.4903	$874,497	$18,440	($1,118)	$894,055	$1,826,426	$932,371	$97,167	$0	($74,696)
2	October 2016	212,594	65	212,529	$4.4988	$956,132	$18,640	($1,447)	$976,220	$2,546,491	$1,570,271	$95,207	$0	($74,328)
3	November 2016	424,540	788	423,752	$4.5055	$1,909,200	$20,828	($3,601)	$1,933,630	$4,235,906	$2,302,276	$121,255	$0	($81,217)
4	TOTAL	831,884	853	831,031		$3,739,829	$57,909	($6,166)	$3,803,905	$8,608,822	$4,804,918	$313,629	$0	($230,241)
5	Off-System Sales										($313,629)			
6	Capacity Release										$0			
7	Gas Cost Audit										$0			
8	TOTAL (OVER)/UNDER-RECOVERY										$4,491,289			
9	Demand Revenues Received										$1,281,973			
10	Demand Cost of Gas										$4,334,525			
11	Demand (Over)/Under Recovery										$3,052,552			
12	Expected Sales Volumes for the Twelve Months End February 28, 2018										11,327,332			
13	**DEMAND ACA TO EXPIRE FEBRUARY 28, 2018**										**$0.2695**			
14	Commodity Revenues Received										$2,521,931			
15	Commodity Cost of Gas										$3,960,668			
16	Commodity (Over)/Under Recovery										$1,438,736			
17	Gas Cost Uncollectible ACA										($10,445)			
18	Total Commodity (Over)/Under Recovery										$1,428,291			
19	Expected Sales Volumes for the Twelve Months End February 28, 2018										11,327,332			
20	**COMMODITY ACA TO EXPIRE FEBRUARY 28, 2018**										**$0.1261**			
21	**TOTAL ACA TO EXPIRE FEBRUARY 28, 2018**										**$0.3956**			

**STATEMENT SHOWING ACTUAL COST
RECOVERY FROM CUSTOMERS TAKING STANDBY
SERVICE UNDER RATE SCHEDULE IS AND GSO
FOR THE THREE MONTHS ENDED NOVEMBER 30, 2016**

LINE NO.	MONTH	SS Commodity Volumes (1) Mcf	Average SS Recovery Rate (2) $/Mcf	SS Commodity Recovery (3) $
1	September 2016	0	$0.0000	$0
2	October 2016	65	$3.0265	$197
3	November 2016	788	$3.0265	$2,385
4	**Total SS Commodity Recovery**			$2,582

LINE NO.	MONTH	SS Demand Volumes (1) Mcf	Average SS Demand Rate (2) $/Mcf	SS Demand Recovery (3) $
5	September 2016	2,707	$6.8121	$18,440
6	October 2016	2,707	$6.8133	$18,444
7	November 2016	2,707	$6.8133	$18,444
8	**Total SS Demand Recovery**			$55,328
9	**TOTAL SS AND GSO RECOVERY**			$57,909

Columbia Gas of Kentucky, Inc.
Gas Cost Uncollectible Charge - Actual Cost Adjustment
For the Three Months Ending November 30, 2016

Line No.	Class	Sep-16	Oct-16	Nov-16	Total
1	**Actual Cost**	$ (5,754)	$ 3,785	$ 5,872	$ 3,903
2	**Actual Recovery**	$ 3,364	$ 3,668	$ 7,317	$ 14,348
3	**(Over)/Under Activity**	**$ (9,117)**	**$ 116**	**$ (1,444)**	**$ (10,445)**

Columbia Gas of Kentucky, Inc.
Actual Cost Adjustment Summary of Rates
For the Period Beginning Billing Unit 1 March 2017

Line No.	Effective Month	Expiration Month	Case Number	ACA Rate
1	June 2016	May 2017	2016-00166	$ 0.0233
2	September 2016	August 2017	2016-00285	$ (0.4021)
3	December 2016	November 2017	2016-00381	$ 0.2201
4	March 2017	February 2018	2017-xxxxx	$ 0.3956
4	Cumulative Rate			$ 0.2369

BALANCING ADJUSTMENT

SCHEDULE NO. 3

Columbia Gas of Kentucky, Inc.
Balancing Adjustment Summary of Rates
For the Period Beginning Billing Unit 1 December 2016

Line No.	Effective Month	Expiration Month	Case Number	ACA Rate
1	December 2016 /1	February 2017	2016-00381	$ (0.4702)
2	Cumulative Rate			$ (0.4702)

/1 Rate will be expiring February 2017 business. No Balancing Adj. will be in effect beginning Unit 1 March 2017.

REFUND ADJUSTMENT

SCHEDULE NO. 4

COLUMBIA GAS OF KENTUCKY, INC.

SUPPLIER REFUND ADJUSTMENT

Line No.	Description	Amount
1	Columbia Gulf Transmission Settlement Refund	($14,215)
2	Interest on Refund Balances	$0
3	Total Refund	($14,215)
4	Projected Sales for the Twelve Months Ended February 28, 2018	13,723,703
5	**TOTAL SUPPLIER REFUND TO EXPIRE FEBRUARY 28, 2018**	**($0.0010)**

Columbia Gas of Kentucky, Inc.
Balancing Adjustment Summary of Rates
For the Period Beginning Billing Unit 1 March 2017

Line No.	Effective Month	Expiration Month	Case Number	ACA Rate
1	September 2016	August 2017	2016-00285	$ (0.0010)
2	March 2017	February 2018	2017-xxxxx	$ (0.0010)
3	Cumulative Rate			$ (0.0020)

TransCanada
In business to deliver

October 24, 2016

Columbia Gulf Transmission, LLC
700 Louisiana Street, Suite 700
Houston, Texas 77002-2700

John A. Roscher
Director, Rates & Regulatory

tel 832.320.5675
fax 832.320.6675
email John_Roscher@TransCanada.com
web www.columbiapipeinfo.com/infopost/

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

Re: Columbia Gulf Transmission, LLC
Compliance Filing, Docket No. RP16-302-000
Docket No. RP16- -

Dear Ms. Bose:

Pursuant to Section 4 of the Natural Gas Act ("NGA") and Part 154 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations,[1] and to comply with the Commission order issued September 22, 2016, in Docket No. RP16-302-000,[2] Columbia Gulf Transmission, LLC ("Columbia Gulf") respectfully submits for filing certain tariff sections to be part of its FERC Gas Tariff, Third Revised Volume No. 1 ("Tariff").[3] The tariff sections are being submitted to implement, in part, the Stipulation and Agreement of Settlement filed on July 26, 2016, in Docket No. RP16-302-000 ("Settlement") and approved by the Commission in the September Order. Columbia Gulf requests that the Commission accept the tariff sections, filed herein as Appendix A, to be effective July 1, 2016, consistent with the terms of the Settlement.

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[1] 18 C.F.R. Part 154 (2016).

[2] *Columbia Gulf Transmission Company,* 154 FERC ¶ 61,189 ("September Order").

[3] Specifically, Part V.1 – Currently Effective Rates, FTS-1 Rates; Part V.3 – Currently Effective Rates, ITS-1 Rates; Part V.5 – Currently Effective Rates, PAL Rates; Part V.6 – Currently Effective Rates, IMS Rates; and Part V.8 – Currently Effective Rates, Retainage Rates.

Correspondence

The names, titles, mailing addresses, and telephone numbers of those persons to whom correspondence and communications concerning this filing should be addressed are as follows:

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* Persons designated for official service pursuant to Rule 2010.

Statement of the Nature, Reasons and Basis for Filing

On January 21, 2016, in Docket No. RP16-302-000, the Commission instituted an investigation pursuant to Section 5 of the NGA into the justness and reasonableness of the existing rates of Columbia Gulf.[4] On July 26, 2016, Columbia Gulf filed its Settlement which resolves all issues raised in the January 21 Order. Article II of the Settlement establishes the Settlement rates, provides that the maximum recourse FTS-1 demand rate will be reduced, and further provides that the ITS rate will be the 100 percent load factor derivative of the Settlement FTS-1 rate, effective July 1, 2016. In its Settlement, Columbia Gulf submitted *pro forma* tariff sections reflecting revised settlement rates.[5]

On September 22, 2016, the Commission issued the September Order approving the Settlement as fair and reasonable and in the public interest, and directing Columbia Gulf to file tariff sections "...as required by the Settlement."[6] Article IX of the Settlement states that "Columbia Gulf shall

[4] *Columbia Gulf Transmission LLC*, 154 FERC ¶ 61,027 ("January 21 Order"), *order on reh'g*, 154 FERC ¶ 61,275 (2016).
[5] *See* Settlement, Appendix B.
[6] *See* September Order, P 10 and ordering paragraph (B).

file to implement the *pro forma* tariff records…in no event later than 30 days after the effective date of this Settlement."[7]

To comply with the Commission's directive in the September Order, and in accordance with the Settlement, Columbia Gulf is submitting, as Appendix A, the settlement rates approved by the Commission in the September Order.

Effective Date and Waiver

In accordance with Section 154.7(a)(3) of the Commission's regulations, Columbia Gulf respectfully requests that the Commission accept the tariff sections, included herein as Appendix A, to be effective July 1, 2016, consistent with the terms of the Settlement. Pursuant to Sections 154.7(a)(7) and 154.207 of the Commission's regulations, Columbia Gulf respectfully requests that the Commission grant all waivers necessary to effectuate this filing.

Other Filings Which May Affect This Proceeding

There are no other filings before the Commission that may significantly affect the changes proposed herein.

Contents of Filing

In accordance with Sections 154.7(a)(1) and 154.7(a)(5) of the Commission's regulations, Columbia Gulf is submitting the following XML filing package, which includes:

1. This transmittal letter;
2. A clean version of the tariff sections (Appendix A); and
3. A marked version of the tariff sections (Appendix B).

Certificate of Service

[7] Article VII.7.3 of the Settlement states that "A Commission order shall be "final"…thirty one (31) days after issuance of the Commission order approving the Settlement" (*i.e.*, final thirty one days after the issuance of the September Order, which is October 24, 2016), and that "this Settlement shall become effective on the first day of the month immediately following the date that a Commission order…becomes final" (*i.e.*, effective on November 1, 2016).

As required by Sections 154.7(b) and 154.208 of the Commission's regulations, copies of this filing are being served upon all parties in this proceeding, all of Columbia Gulf's existing customers and interested state regulatory agencies. A copy of this letter, together with the attachments, is available for public inspection during regular business hours at Columbia Gulf's principal place of business.

Pursuant to Section 385.2005 and Section 385.2011(c)(5) of the Commission's regulations, the undersigned has read this filing and knows its contents, and the contents are true as stated, to the best of his knowledge and belief. The undersigned possesses full power and authority to sign such filing.

Any questions regarding this filing may be directed to Sorana Linder at (832) 320-5209.

Respectfully submitted,

COLUMBIA GULF TRANSMISSION, LLC

John A. Roscher

John A. Roscher
Director, Rates & Regulatory

Enclosures

Appendix A

Columbia Gulf Transmission, LLC
FERC Gas Tariff, Third Revised Volume No. 1

Clean Tariff

Tariff Sections	Version
V.1 – Currently Effective Rates, FTS-1 Rates	13.0.0
V.3 – Currently Effective Rates, ITS-1 Rates	11.0.0
V.5 – Currently Effective Rates, PAL Rates	8.0.0
V.6 – Currently Effective Rates, IMS Rates	8.0.0
V.8 – Currently Effective Rates, Retainage Rates	17.0.0

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	4.170	4.170	0.1371
Minimum	0.000	0.000	0.000
Commodity			
Maximum	0.0109	0.0109	0.0109
Minimum	0.0109	0.0109	0.0109
Overrun			
Maximum	0.1480	0.1480	0.1480
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 ITS-1
Rates in Dollars per Dth

Rate Schedule ITS-1	Base Rate (1) 1/	Total Effective Rate (2) 1/	Daily Rate (3) 1/
Market Zone			
Commodity			
Maximum	0.1480	0.1480	0.1480
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 PAL
Rate in Dollars per Dth

Account Balance Charge

	Total Effective Daily Rate
Market Zone	
Maximum	0.1480
Minimum	0.0000

Currently Effective Rates
Applicable to Rate Schedule IMS
Rate in Dollars per Dth

Rate Schedule IMS Account Balance Charge	Total Effective Daily Rate
Market Zone	
Maximum	0.1480
Minimum	0.0000

RETAINAGE RATES

	Company Use & Unaccounted For 1/	Surcharge	Total Effective Rate
Market Zone 2/			
(mainline)	0.602%	0.049%	0.651%
(former onshore)	0.437%	0.049%	0.486%

1/ For service provided over Transporter's East Lateral Efficiency Optimization Project facilities, Shipper's delivered quantities will be reduced to reflect actual lost and unaccounted for quantities.

2/ Agreements containing the terms "Forwardhaul," "Market Zone – Forwardhaul," "Backhaul," "Market Zone – Backhaul," or words of similar import to describe the applicable retainage rate will be assessed the Market Zone mainline retainage rate.

CKY
Transportation Invoice Actual Detail
For the Flow Month: DECEMBER -2016

JE ID	Pipe	Invoice	Flow Month	Pay Due Date	Contract	Rate Schedule	Cost Elem Description	Receipt Pt/Offer #	Total Volume	Avg Rate	Tot Dollars	Comp Code	Account	Cost Object	Cost Element
18101	CGT	161100074	NOV-16	12-22-2016	79921	FTS-1	Capacity Release - Marketed	25762933	(13,000)	$0.6000	($7,800.00)	32	80300400	GP62	3858
		161100074	NOV-16	12-22-2016	79921	FTS-1	Capacity Release - Unbundled / Choice	25761778	(52)	$4.1700	($216.84)	32	80300400	GP62	3856
		161100074	NOV-16	12-22-2016	79921	FTS-1	Capacity Release - Unbundled / Choice	25761779	(1,394)	$4.1700	($5,812.98)	32	80300400	GP62	3856
		161100074	NOV-16	12-22-2016	79921	FTS-1	Capacity Release - Unbundled / Choice	25761783	(60)	$4.1700	($250.20)	32	80300400	GP62	3856
		161100074	NOV-16	12-22-2016	79921	FTS-1	Capacity Release - Unbundled / Choice	25761786	(3,253)	$4.1700	($13,565.01)	32	80300400	GP62	3856
		161100074	NOV-16	12-22-2016	79921	FTS-1	Capacity Release - Unbundled / Choice	25761789	(73)	$4.1700	($304.41)	32	80300400	GP62	3856
		161100074	NOV-16	12-22-2016	79921	FTS-1	Transportation Demand		28,991	$4.1700	$120,892.47	32	80300400	GP62	3844
		161100074	NOV-16	12-22-2016	79921	FTS-1	Capacity Release - Unbundled / Choice	25761818	(206)	$4.1700	($859.02)	32	80300400	GP62	3856
		161100074	NOV-16	12-22-2016	79921	FTS-1	Capacity Release - Unbundled / Choice	25761822	(547)	$4.1700	($2,280.99)	32	80300400	GP62	3856
		161100074	NOV-16	12-22-2016	79921	FTS-1	Capacity Release - Unbundled / Choice	25761824	(88)	$4.1700	($366.96)	32	80300400	GP62	3856
		161100074	NOV-16	12-22-2016	79921	FTS-1	Capacity Release - Unbundled / Choice	25761827	(37)	$4.1700	($154.29)	32	80300400	GP62	3856
		161100074	NOV-16	12-22-2016	79921	FTS-1	Other / Transportation Commodity - Reim				($14,215.44)	32	80300400	GP62	3825
		161100074	NOV-16	12-22-2016	79921	FTS-1	Capacity Release - Unbundled / Choice	25761791	(213)	$4.1700	($888.21)	32	80300400	GP62	3856

	Total Volume	Tot Dollars
Commodity Total for CGT	0	$0.00
Demand Total for CGT	28,991	$120,892.47
Capacity Release Total for CGT	(18,923)	($32,498.91)
Grand Total for CGT	10,068	$74,178.12
Fuel Volumes for CGT	0	

JE ID	Pipe	Invoice	Flow Month	Pay Due Date	Contract	Rate Schedule	Cost Elem Description	Receipt Pt/Offer #	Total Volume	Avg Rate	Tot Dollars	Comp Code	Account	Cost Object	Cost Element
	TCO	161100116	NOV-16	12-22-2016	80171	FSS	Storage Commodity - Injections		153,003	$0.0153	$2,340.95	32	80300500	GP61	3840
		161100116	NOV-16	12-22-2016			Other / Transportation Commodity - Reim				($5,445.00)	32	80300400	GP61	3825
		161100116	NOV-16	12-22-2016	81540	SST	Transportation Demand		30,000	$4.1850	$125,550.00	32	80300400	GP61	3844
		161100116	NOV-16	12-22-2016	81527	FTS	Transportation Demand		20,014	$6.1900	$123,886.66	32	80300400	GP61	3844
		161100116	NOV-16	12-22-2016	81527	FTS	Transportation Commodity - Firm	TMBRDRU	7,849	$0.0194	$152.27	32	80300400	GP61	3845
		161100116	NOV-16	12-22-2016	81527	FTS	Transportation Commodity - Firm	B9	176,580	$0.0194	$3,425.65	32	80300400	GP61	3845
		161100116	NOV-16	12-22-2016	81527	FTS	Capacity Release - Unbundled / Choice	25762572	(27)	$6.1900	($167.13)	32	80300400	GP61	3856
		161100116	NOV-16	12-22-2016	81527	FTS	Capacity Release - Unbundled / Choice	25762571	(63)	$6.1900	($389.97)	32	80300400	GP61	3856
		161100116	NOV-16	12-22-2016	81527	FTS	Capacity Release - Unbundled / Choice	25762570	(388)	$6.1900	($2,401.72)	32	80300400	GP61	3856
		161100116	NOV-16	12-22-2016	81527	FTS	Capacity Release - Unbundled / Choice	25762568	(147)	$6.1900	($909.93)	32	80300400	GP61	3856
		161100116	NOV-16	12-22-2016	81527	FTS	Capacity Release - Unbundled / Choice	25762567	(152)	$6.1900	($940.88)	32	80300400	GP61	3856
		161100116	NOV-16	12-22-2016	81527	FTS	Capacity Release - Unbundled / Choice	25762566	(53)	$6.1900	($328.07)	32	80300400	GP61	3856
		161100116	NOV-16	12-22-2016	81527	FTS	Capacity Release - Unbundled / Choice	25762565	(2,309)	$6.1900	($14,292.71)	32	80300400	GP61	3856
		161100116	NOV-16	12-22-2016	81527	FTS	Capacity Release - Unbundled / Choice	25762559	(43)	$6.1900	($266.17)	32	80300400	GP61	3856
		161100116	NOV-16	12-22-2016	81527	FTS	Capacity Release - Unbundled / Choice	25762558	(990)	$6.1900	($6,128.10)	32	80300400	GP61	3856
		161100116	NOV-16	12-22-2016	81527	FTS	Capacity Release - Unbundled / Choice	25762356	(37)	$6.1900	($229.03)	32	80300400	GP61	3856
		161100116	NOV-16	12-22-2016	80171	FSS	Storage Demand - SCQ		11,264,911	$0.0288	$324,429.44	32	80300808	GP61	3839
		161100116	NOV-16	12-22-2016	80171	FSS	Storage Demand - MDQ		220,880	$1.5010	$331,540.88	32	80300808	GP61	3838
		161100116	NOV-16	12-22-2016	80171	FSS	Storage Commodity - Withdrawals		840,183	$0.0153	$12,854.80	32	80300500	GP61	3836
		161100116	OCT-16	12-22-2016	80171	FSS	Storage Commodity - Withdrawals		0	$0.0000	$19.80	32	80300500	GP61	3836
		161100116	NOV-16	12-22-2016	80171	FSS	Storage Commodity - Withdrawals	STOR	145,000	$0.0153	$2,218.50	32	80300500	GP61	3836
		161100116	OCT-16	12-22-2016	80171	FSS	Storage Commodity - Injections		0	$0.0000	($8.86)	32	80300500	GP61	3840
		161100116	NOV-16	12-22-2016	80160	SST	Capacity Release - Marketed	25737576	(1)	$6.0200	($6.02)	32	80300400	GP61	3858
		161100116	NOV-16	12-22-2016	80160	SST	Transportation Commodity - Firm	P1042737	129,503	$0.0192	$2,486.46	32	80300400	GP61	3845
		161100116	NOV-16	12-22-2016	80160	SST	Transportation Commodity - Firm	STOR	0	$0.0000	($118.21)	32	80300400	GP61	3845
		161100116	OCT-16	12-22-2016	80160	SST	Transportation Commodity - Firm		0	$0.0000	$26.63	32	80300400	GP61	3845

PIPELINE COMPANY TARIFF SHEETS

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	0.019	1.044	6.136	0.2017
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	0.06	3.43	21.98	21.98
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 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	0.019	1.044	5.966	0.1961
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	0.06	3.43	21.40	21.40
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 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	1.893%
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	4.170	4.170	0.1371
Minimum	0.000	0.000	0.000
Commodity			
Maximum	0.0109	0.0109	0.0109
Minimum	0.0109	0.0109	0.0109
Overrun			
Maximum	0.1480	0.1480	0.1480
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%

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	$0.0041		$0.0124	$0.0186	$0.0228	$0.2677	$0.2555	$0.3039
L		$0.0021						
1	$0.0051		$0.0090	$0.0156	$0.0188	$0.2278	$0.2322	$0.2650
2	$0.0176		$0.0096	$0.0021	$0.0037	$0.0743	$0.1187	$0.1314
3	$0.0216		$0.0178	$0.0035	$0.0011	$0.0991	$0.1367	$0.1491
4	$0.0259		$0.0214	$0.0096	$0.0114	$0.0463	$0.0651	$0.1050
5	$0.0293		$0.0265	$0.0109	$0.0127	$0.0648	$0.0642	$0.0796
6	$0.0355		$0.0309	$0.0152	$0.0172	$0.0993	$0.0542	$0.0333

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 $0.0009.

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, 2005 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. <u>Incorporation of Recitals; Definitions</u>. 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. <u>Invoicing by Owner-Operator</u>. 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. <u>Payment by CKY</u>. 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. <u>Term; Termination</u>.

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

PROPOSED TARIFF SHEETS

COLUMBIA GAS OF KENTUCKY, INC.

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	16.00			16.00	
Delivery Charge per Mcf	3.5665	2.0757	3.9470	9.5892	I
RATE SCHEDULE GSO					
Commercial or Industrial					
Customer Charge per billing period	44.69			44.69	
Delivery Charge per Mcf -					
First 50 Mcf or less per billing period	3.0181	2.0757	3.9470	9.0408	I
Next 350 Mcf per billing period	2.3295	2.0757	3.9470	8.3522	I
Next 600 Mcf per billing period	2.2143	2.0757	3.9470	8.2370	I
Over 1,000 Mcf per billing period	2.0143	2.0757	3.9470	8.0370	I
RATE SCHEDULE IS					
Customer Charge per billing period	2007.00			2007.00	
Delivery Charge per Mcf					
First 30,000 Mcf per billing period	0.6285		3.9470 [2/]	4.5755	I
Next 70,000 Mcf per billing period	0.3737		3.9470 [2/]	4.3207	I
Over 100,000 Mcf per billing period	0.3247		3.9470 [2/]	4.2717	I
Firm Service Demand Charge					
Demand Charge times Daily Firm					
Volume (Mcf) in Customer Service Agreement		7.0290		7.0290	I
RATE SCHEDULE IUS					
Customer Charge per billing period	567.40			567.40	
Delivery Charge per Mcf					
For All Volumes Delivered	1.1544	2.0757	3.9470	7.1771	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 $5.4210 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.

DATE OF ISSUE January 31, 2017

DATE EFFECTIVE March 1, 2017 (Unit 1 March)

ISSUED BY Herbert A. Miller, Jr.

TITLE President

COLUMBIA GAS OF KENTUCKY, INC.

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		7.0290		7.0290	I
Standby Service Commodity Charge per Mcf			3.9470	3.9470	I
RATE SCHEDULE DS					
Customer Charge per billing period [2/]				2007.00	
Customer Charge per billing period (GDS only)				44.69	
Customer Charge per billing period (IUDS only)				567.40	
Delivery Charge per Mcf[2/]					
First 30,000 Mcf	0.6285			0.6285	
Next 70,000 Mcf	0.3737			0.3737	
Over 100,000 Mcf	0.3247			0.3247	
– Grandfathered Delivery Service					
First 50 Mcf or less per billing period				3.0181	
Next 350 Mcf per billing period				2.3295	
Next 600 Mcf per billing period				2.2143	
All Over 1,000 Mcf per billing period				2.0143	
– Intrastate Utility Delivery Service					
All Volumes per billing period				1.1544	
Banking and Balancing Service					
Rate per Mcf		0.0215		0.0215	I
RATE SCHEDULE MLDS					
Customer Charge per billing period				255.90	
Delivery Charge per Mcf				0.0858	
Banking and Balancing Service					
Rate per Mcf		0.0215		0.0215	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.

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

DATE OF ISSUE January 31, 2017

DATE EFFECTIVE March 1, 2017 (Unit 1 March)

ISSUED BY Herbert A. Miller, Jr.

TITLE President

CURRENTLY EFFECTIVE BILLING RATES
(Continued)

RATE SCHEDULE SVGTS		**Base Rate Charge** $	
General Service Residential (SGVTS GSR)			
Customer Charge per billing period		16.00	
Delivery Charge per Mcf		3.5665	
General Service Other - Commercial or Industrial (SVGTS GSO)			
Customer Charge per billing period		44.69	
Delivery Charge per Mcf -			
First 50 Mcf or less per billing period		3.0181	
Next 350 Mcf per billing period		2.3295	
Next 600 Mcf per billing period		2.2143	
Over 1,000 Mcf per billing period		2.0143	
Intrastate Utility Service			
Customer Charge per billing period		567.40	
Delivery Charge per Mcf		$ 1.1544	
	Billing Rate		
Actual Gas Cost Adjustment 1/			
For all volumes per billing period per Mcf	($0.0034)		I
RATE SCHEDULE SVAS			
Balancing Charge – per Mcf	$1.8834		I

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 January 31, 2017

DATE EFFECTIVE March 1, 2017 (Unit 1 March)

ISSUED BY Hubert A. Miller, Jr.

TITLE President