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

January 30, 2018

RECEIVED
JAN 30 2018
PUBLIC SERVICE
COMMISSION

Ms. Gwen Pinson
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. 2018 – 00049

Dear Ms. Pinson:

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 $0.0391 per Mcf effective with its March 2018 billing cycle on March 1, 2018. The increase is composed of a decrease of ($0.4040) per Mcf in the Average Commodity Cost of Gas, an increase of $0.0087 per Mcf in the Average Demand Cost of Gas, an increase of $0.3807 per Mcf in the Balancing Adjustment, an increase of $0.0010 per Mcf in the Supplier Refund Adjustment, and an increase of $0.0527 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

BEFORE THE
PUBLIC SERVICE COMMISSION
OF KENTUCKY

COLUMBIA GAS OF KENTUCKY, INC.

CASE 2018 – 00049

GAS COST ADJUSTMENT AND REVISED RATES OF
COLUMBIA GAS OF KENTUCKY, INC. PROPOSED TO BECOME
EFFECTIVE MARCH 2018 BILLINGS

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

Line No.		December-17 CURRENT	March-18 PROPOSED	DIFFERENCE
1	Commodity Cost of Gas	$3.4127	$3.0087	($0.4040)
2	Demand Cost of Gas	$1.4816	$1.4903	$0.0087
3	Total: Expected Gas Cost (EGC)	$4.8943	$4.4990	($0.3953)
4	SAS Refund Adjustment	$0.0000	$0.0000	$0.0000
5	Balancing Adjustment	($0.0855)	$0.2952	$0.3807
6	Supplier Refund Adjustment	($0.0010)	$0.0000	$0.0010
7	Actual Cost Adjustment	$0.2003	$0.2530	$0.0527
8	Performance Based Rate Adjustment	$0.3548	$0.3548	$0.0000
9	Cost of Gas to Tariff Customers (GCA)	$5.3629	$5.4020	$0.0391
10	Transportation TOP Refund Adjustment	$0.0000	$0.0000	$0.0000
11	Banking and Balancing Service	$0.0217	$0.0216	($0.0001)
12	Rate Schedule FI and GSO			
13	Customer Demand Charge	$7.0340	$7.0529	$0.0189

Columbia Gas of Kentucky, Inc.
Gas Cost Adjustment Clause
Gas Cost Recovery Rate
Mar - May 18

Line No.	Description				Amount	Expires
1	Expected Gas Cost (EGC)	Schedule No. 1			$4.4990	05-31-18
2	Total Actual Cost Adjustment (ACA)	Schedule No. 2			$0.2530	
			Case No. 2017-00185	$0.2011		05-31-18
			Case No. 2017-00317	($0.4147)		08-31-18
			Case No. 2017-00423	$0.0183		11-30-18
			Case No. 2018-xxxxx	$0.4483		02-28-19
3	Total Supplier Refund Adjustment (RA)	Schedule No. 4			$0.0000	
4	Balancing Adjustment (BA)	Schedule No. 3	Case No. 2018-xxxxx		$0.2952	05-31-18
5	Performance Based Rate Adjustment (PBRA)	Schedule No. 6	Case No. 2017-00185		$0.3548	05-31-18
6	Gas Cost Adjustment					
7	Mar - May 18				$5.4020	
8	Expected Demand Cost (EDC) per Mcf					
9	(Applicable to Rate Schedule IS/SS and GSO)	Schedule No. 1, Sheet 4			$7.0529	

DATE FILED: January 30, 2018 BY: J. M. Cooper

Columbia Gas of Kentucky, Inc.
Expected Gas Cost for Sales Customers
Mar - May 18

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				(1,267,000)		$0.0153	$19,385
2	Injection				2,253,271		$0.0153	$34,475
3	Withdrawals: gas cost includes pipeline fuel and commodity charges				1,253,000		$2.5858	$3,240,007
	Total							
4	Volume	= 3			1,253,000			
5	Cost	sum(1:3)						$3,293,867
6	Summary	4 or 5			1,253,000			$3,293,867
	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		1,246,193			$3,202,716
8	Appalachian Supplies		Sch.1, Sht. 6, Ln. 4		91,507			$298,775
9	Less Fuel Retention By Interstate Pipelines		Sch. 1,Sheet 7, Lines 21, 22		(74,439)			($196,295)
10	Total	7 + 8 + 9			1,263,261			$3,305,196
	Total Supply							
11	At City-Gate		Line 6 + 10		2,516,261			$6,599,063
	Lost and Unaccounted For							
12	Factor				-0.5%			
13	Volume		Line 11 * 12		(12,581)			
14	At Customer Meter		Line 11 + 13	2,274,005	2,503,680			
15	Less: Right-of-Way Contract Volume			825				
16	**Sales Volume**		Line 14-15	2,273,180				
	Unit Costs $/MCF							
	Commodity Cost							
17	Excluding Cost of Pipeline Retention		Line 11 / Line 16			$2.9030		
18	Annualized Unit Cost of Retention		Sch. 1,Sheet 7, Line 24			$0.0782		
19	Including Cost of Pipeline Retention		Line 17 + 18			$2.9812		
20	Uncollectible Ratio		CN 2016-00162			0.00923329		
21	Gas Cost Uncollectible Charge		Line 19 * Line 20			$0.0275		
22	Total Commodity Cost		line 19 + line 21			$3.0087		
23	Demand Cost		Sch.1, Sht. 2, Line 10			$1.4903		
24	Total Expected Gas Cost (EGC)		Line 22 + 23			$4.4990		

A/ BTU Factor = 1.1010 Dth/MCF

Columbia Gas of Kentucky, Inc.
GCA Unit Demand Cost
Mar - May 18

Schedule No. 1
Sheet 2

Line No.	Description		Reference		
1	Expected Demand Cost: Annual Mar - Feb 2019		Sch. No.1, Sheet 3, Ln. 11	$20,669,979	
2	Less Rate Schedule IS/SS and GSO Customer Demand Charge Recovery		Sch. No.1, Sheet 4, Ln. 10	-$221,659	
3	Less Storage Service Recovery from Delivery Service Customers			-$225,831	
4	Net Demand Cost Applicable	1 + 2 + 3		$20,222,489	
	Projected Annual Demand: Sales + Choice				
	At city-gate				
	In Dth			15,018,368	Dth
	Heat content			1.1010	Dth/MCF
5	In MCF			13,640,661	MCF
	Lost and Unaccounted - For				
6	Factor			0.5%	
7	Volume	5 * 6		68,203	MCF
8	Right of way Volumes			2,829	
9	At Customer Meter	5 - 7- 8		13,569,629	MCF
10	Unit Demand Cost (4/ 9)	To Sheet 1, line 23		$1.4903	per MCF

Columbia Gas of Kentucky, Inc.
Annual Demand Cost of Interstate Pipeline Capacity
Mar - Feb 2019

Schedule No. 1
Sheet 3

Line No.	Description		Dth	Monthly Rate $/Dth	# Months	Expected Annual Demand Cost
	Columbia Gas Transmission Corporation					
	Firm Storage Service (FSS)					
1	FSS Max Daily Storage Quantity (MDSQ)		220,880	$1.5010	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	$6.7190	12	$1,613,689
6	Subtotal	sum(1:5)				$17,804,778
	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					$20,669,979

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 2019

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)						$20,669,979
	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				$7.0529	/Mcf	
9	Firm Volumes of IS/SS and GSO Customers		2,619	12	31,428	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		$221,659

Columbia Gas of Kentucky, Inc.
Non-Appalachian Supply: Volume and Cost
Mar - May 18

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-18	186,000	$523,000		0	186,000	
2	Apr-18	1,567,275	$4,019,971		(865,979)	701,296	
3	May-18	1,732,189	$4,415,246		(1,373,292)	358,897	
4	Total 1+2+3	3,485,464	$8,958,217	$2.57	(2,239,271)	1,246,193	$3,202,716

A/ Gross, before retention.

Columbia Gas of Kentucky, Inc. Schedule No. 1
Appalachian Supply: Volume and Cost Sheet 6
Mar - May 18

Line No.	Month		Dth (2)	Cost (3)
1	Mar-18		40,000	$138,000
2	Apr-18		29,563	$94,024
3	May-18		21,944	$66,751
4	Total	1 + 2 + 3	91,507	$298,775

Columbia Gas of Kentucky, Inc.
Annualized Unit Charge for Gas Retained by Upstream Pipelines
Mar - May 18

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 18	Jun - Aug 18	Sep - Nov 18	Dec - Feb 19	Annual Mar - Feb 2019
	Gas purchased by CKY for the remaining sales customers							
1	Volume		Dth	3,576,971	4,650,182	2,488,625	1,445,368	12,161,146
2	Commodity Cost including Transportation			$9,256,991	$12,095,679	$6,497,747	$4,218,458	$32,068,876
3	Unit cost		$/Dth					$2.6370
	Consumption by the remaining sales customers							
11	At city gate		Dth	2,516,879	554,904	1,861,346	6,499,204	11,432,333
12	Lost and unaccounted for portion			0.50%	0.50%	0.50%	0.50%	
	At customer meters							
13	In Dth	(100% - 12) * 11	Dth	2,504,295	552,129	1,852,039	6,466,708	11,375,171
14	Heat content		Dth/MCF	1.1010	1.1010	1.1010	1.1010	
15	In MCF	13 / 14	MCF	2,274,564	501,480	1,682,143	5,873,486	10,331,673
16	Portion of annual	line 15, quarterly / annual		22.0%	4.9%	16.3%	56.8%	100.0%
	Gas retained by upstream pipelines							
21	Volume		Dth	74,439	73,745	52,332	106,081	306,597
	Cost			To Sheet 1, line 9				
22	Quarterly. Deduct from Sheet 1	3 * 21		$196,295	$194,465	$137,999	$279,735	$808,494
23	Allocated to quarters by consumption			$177,869	$39,616	$131,785	$459,225	$808,495
				To Sheet 1, line 18				
24	Annualized unit charge	23 / 15	$/MCF	$0.0782	$0.0790	$0.0783	$0.0782	$0.0783

Schedule No. 1

Sheet 8

COLUMBIA GAS OF KENTUCKY, INC.

DETERMINATION OF THE BANKING AND BALANCING CHARGE FOR THE PERIOD BEGINNING MARCH 2018

Line No.	Description	Dth	Detail	Amount For Transportation Customers
1	Total Storage Capacity. Sheet 3, line 2	11,264,911		
2	Net Transportation Volume	11,501,224		
3	Contract Tolerance Level @ 5%	575,061		
4	Percent of Annual Storage Applicable			
5	to Transportation Customers		5.10%	
6	Seasonal Contract Quantity (SCQ)			
7	Rate		$0.0288	
8	SCQ Charge - Annualized		$3,893,153	
9	Amount Applicable To Transportation Customers			$198,551
10	FSS Injection and Withdrawal Charge			
11	Rate		0.0306	
12	Total Cost		$344,706	
13	Amount Applicable To Transportation Customers			$17,580
14	SST Commodity Charge			
15	Rate		0.0224	
16	Projected Annual Storage Withdrawal, Dth		8,490,464	
17	Total Cost		$190,186	
18	Amount Applicable To Transportation Customers			$9,700
19	Total Cost Applicable To Transportation Customers			$225,831
20	Total Transportation Volume - Mcf			17,158,001
21	Flex and Special Contract Transportation Volume - Mcf			(6,711,839)
22	Net Transportation Volume - Mcf	line 20 + line 21		10,446,162
23	Banking and Balancing Rate - Mcf.	Line 19 / line 22. To line 11 of the GCA Comparison		$0.0216

DETAIL SUPPORTING

DEMAND/COMMODITY SPLIT

COLUMBIA GAS OF KENTUCKY
CASE NO. 2018- Effective March 2018 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)	$1.4903	
Demand ACA (Schedule No. 2, Sheet 1, Case No. 2017-00185, Case No. 2017-00317, Case No. 2017-00423 & Case No. 2018-)	$0.1344	
Refund Adjustment (Schedule No. 4, Case No. 201X-)	$0.0000	
Total Demand Rate per Mcf	$1.6247	<-- to Att. E, line 15
Commodity Component of Gas Cost Adjustment		
Commodity Cost of Gas (Schedule No. 1, Sheet 1, Line 22)	$3.0087	
Commodity ACA (Schedule No. 2, Sheet 1, Case No. 2017-00185, Case No. 2017-00317, & Case No. 2017-00423 & Case No. 2018-)	$0.1186	
Balancing Adjustment	$0.2952	
Performance Based Rate Adjustment (Schedule No. 6, Case No. 2017-00185)	$0.3548	
Total Commodity Rate per Mcf	$3.7773	
CHECK:	$1.6247	
	$3.7773	
COST OF GAS TO TARIFF CUSTOMERS (GCA)	$5.4020	
Calculation of Rate Schedule SVGTS - Actual Gas Cost Adjustment		
Commodity ACA (Schedule No. 2, Sheet 1, Case No. 2017-00185, Case No. 2017-00317, & Case No. 2017-00423 & Case No. 2018-)	$0.1186	
Balancing Adjustment	$0.2952	
Performance Based Rate Adjustment (Schedule No. 6, Case No. 2017-00185)	$0.3548	
Total Commodity Rate per Mcf	$0.7686	

Columbia Gas of Kentucky, Inc.
CKY Choice Program
100% Load Factor Rate of Assigned FTS Capacity
Balancing Charge
Mar - May 18

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	0.579%						
3	TCO FTS		20,014	1.432%						
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				$6.7190	12	0.4168	1.0000	$33.6058	
11	Gulf FTS-1, upstream to CKT FTS				$4.1700	12	0.5832	1.0058	$29.3533	
12	TGP FTS-A, upstream to TCO FTS				$4.5835	12	0.4168	1.0145	$23.2579	
13	Total Demand Cost of Assigned FTS, per unit								$89.7792	$98.8469
14	100% Load Factor Rate (Line 13 / 365 days)									$0.2708
	Balancing charge, paid by Choice marketers									
15	Demand Cost Recovery Factor in GCA, per Mcf per CKY Tariff Sheet No. 5									$1.6247
16	Less credit for cost of assigned capacity									($0.2708)
17	Plus storage commodity costs incurred by CKY for the Choice marketer									$0.0589
18	Balancing Charge, per Mcf sum(15:17)									$1.4128

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, 2017

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 2017	203,648	208	203,440	$4.5538	$926,415	$19,087	($2,216)	$947,718	$854,473	($93,245)	$54,408	$0	($86,920
2	October 2017	226,250	287	225,963	$4.5558	$1,029,429	$19,169	($2,221)	$1,050,819	$3,607,410	$2,556,591	$42,273	$0	($86,650
3	November 2017	696,230	2,189	694,041	$4.5640	$3,167,613	$25,295	($6,696)	$3,199,605	$5,516,042	$2,316,437	$40,194	$0	($85,965
4	TOTAL	1,126,127	2,684	1,123,443		$5,123,457	$63,551	($11,134)	$5,198,142	$9,977,926	$4,779,784	$136,874	$0	($259,535

Line No.		(OVER)/ UNDER RECOVERY $
5	Off-System Sales	($136,874)
6	Capacity Release	$0
7	Gas Cost Audit	$0
8	TOTAL (OVER)/UNDER-RECOVERY	$4,642,909
9	Demand Revenues Received	$1,727,606
10	Demand Cost of Gas	$4,763,609
11	Demand (Over)/Under Recovery	$3,036,002
12	Expected Sales Volumes for the Twelve Months End February 28, 2019	10,328,542
13	**DEMAND ACA TO EXPIRE FEBRUARY 28, 2019**	**$0.2939**
14	Commodity Revenues Received	$3,470,536
15	Commodity Cost of Gas	$5,077,443
16	Commodity (Over)/Under Recovery	$1,606,907
17	Gas Cost Uncollectible ACA	($11,903)
18	Total Commodity (Over)/Under Recovery	$1,595,004
19	Expected Sales Volumes for the Twelve Months End February 28, 2019	10,328,542
20	**COMMODITY ACA TO EXPIRE FEBRUARY 28, 2019**	**$0.1544**
21	**TOTAL ACA TO EXPIRE FEBRUARY 28, 2019**	**$0.4483**

STATEMENT SHOWING ACTUAL COST RECOVERY FROM CUSTOMERS TAKING STANDBY SERVICE UNDER RATE SCHEDULE IS AND GSO FOR THE THREE MONTHS ENDED NOVEMBER 30, 2017

LINE NO.	MONTH	SS Commodity Volumes (1) Mcf	Average SS Recovery Rate (2) $/Mcf	SS Commodity Recovery (3) $
1	September 2017	208	$3.8375	$798
2	October 2017	287	$3.0692	$881
3	November 2017	2,189	$3.0692	$6,718
4	**Total SS Commodity Recovery**			$8,398

LINE NO.	MONTH	SS Demand Volumes (1) Mcf	Average SS Demand Rate (2) $/Mcf	SS Demand Recovery (3) $
5	September 2017	2,600	$7.0340	$18,288
6	October 2017	2,600	$7.0340	$18,288
7	November 2017	2,641	$7.0340	$18,577
8	**Total SS Demand Recovery**			$55,154
9	**TOTAL SS AND GSO RECOVERY**			$63,551

Columbia Gas of Kentucky, Inc.
Gas Cost Uncollectible Charge - Actual Cost Adjustment
For the Three Months Ending November 30, 2017

Line No.	Class	Sep-17	Oct-17	Nov-17	Total
1	**Actual Cost**	$ (954)	$ 4,039	$ 16,984	$ 20,069
2	**Actual Recovery**	$ 5,784	$ 6,427	$ 19,761	$ 31,972
3	**(Over)/Under Activity**	**$ (6,738)**	**$ (2,388)**	**$ (2,777)**	**$ (11,903)**

BALANCING ADJUSTMENT

SCHEDULE NO. 3

COLUMBIA GAS OF KENTUCKY, INC.

CALCULATION OF BALANCING ADJUSTMENT
TO BE EFFECTIVE MARCH 1, 2018

Line No.	Description	Detail $	Amount $
1	**RECONCILIATION OF A PREVIOUS SUPPLIER REFUND ADJUSTMENT**		
2	Total adjustment to have been distributed to		
3	customers in Case No. 201X-XXXXX	$0	
4	Less: actual amount distributed	$0	
5	REMAINING AMOUNT		$0
6	**RECONCILIATION OF A PREVIOUS BALANCING ADJUSTMENT**		
7	Total adjustment to have been collected from		
8	customers in Case No. 2017-00317	$551,799	
9	Less: actual amount collected	$372,691	
10	REMAINING AMOUNT		$179,108
11	**RECONCILIATION OF PREVIOUS ACTUAL COST ADJUSTMENT**		
12	Total adjustment to have been collected from		
13	customers in Case No. 2016-00381	$2,403,225	
14	Less: actual amount collected	$1,911,197	
15	REMAINING AMOUNT		$492,028
16	**TOTAL BALANCING ADJUSTMENT AMOUNT**		**$671,137**
17	Divided by: projected sales volumes for the three months		
18	ended May 31, 2018		2,273,848
19	**BALANCING ADJUSTMENT (BA) TO**		
20	**EXPIRE MAY 31, 2018**		**$ 0.2952**

Columbia Gas of Kentucky, Inc.
Balancing Adjustment
Supporting Data

Case No. 2017-00317

Expires: December 31, 2017	Volume	Surcharge Rate	Surcharge Amount	Surcharge Balance
Beginning Balance				$551,799
September 2017	203,924	$0.3286	$67,009	$484,790
October 2017	226,206	$0.3286	$74,331	$410,459
November 2017	694,702	$0.3286	$228,279	$182,180
December 2017	9,348	$0.3286	$3,072	$179,108
TOTAL SURCHARGE COLLECTED				

<u>SUMMARY:</u>

SURCHARGE AMOUNT	$551,799
AMOUNT COLLECTED	$372,691
REMAINING BALANCE	$179,108

Columbia Gas of Kentucky, Inc.
Actual Cost Adjustment YR2016 QTR3
Supporting Data

Case No. 2016-00381

Expires: December 31, 2017

	Tariff			Choice			
	Volume	Refund Rate	Refund Amount	Volume	Refund Rate	Refund Amount	Refund Balance
							$2,403,225
Dec-16	1,360,480	$0.2201	$299,442	8,050	($0.0081)	($65)	$2,103,849
Jan-17	1,904,126	$0.2201	$419,098	11,142	($0.0081)	($90)	$1,684,841
Feb-17	1,448,051	$0.2201	$318,716	9,249	($0.0081)	($75)	$1,366,200
Mar-17	1,147,263	$0.2201	$252,513	12,547	($0.0081)	($102)	$1,113,789
Apr-17	776,014	$0.2201	$170,801	5,917	($0.0081)	($48)	$943,036
May-17	343,024	$0.2201	$75,499	2,771	($0.0081)	($22)	$867,559
Jun-17	234,885	$0.2201	$51,698	2,973	($0.0081)	($24)	$815,885
Jul-17	188,891	$0.2201	$41,575	3,776	($0.0081)	($31)	$774,341
Aug-17	165,249	$0.2201	$36,371	2,112	($0.0081)	($17)	$737,986
Sep-17	201,908	$0.2201	$44,440	2,107	($0.0081)	($17)	$693,564
Oct-17	224,217	$0.2201	$49,350	1,989	($0.0081)	($16)	$644,230
Nov-17	688,122	$0.2201	$151,456	6,580	($0.0081)	($53)	$492,827
Dec-17	3,833	$0.2201	$844	5,515	($0.0081)	($45)	$492,028

SUMMARY:	
REFUND AMOUNT	2,403,225
LESS	
AMOUNT REFUNDED	1,911,197
TOTAL REMAINING REFUND	492,028

PIPELINE COMPANY TARIFF SHEETS

RETAINAGE PERCENTAGES

Transportation Retainage	1.432%
Gathering Retainage	4.000%
Storage Gas Loss Retainage	0.170%
Ohio Storage Gas Lost Retainage	0.280%
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.

RETAINAGE PERCENTAGE

Transportation Retainage 0.579%

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	0.205	0.065	-0.016	~~1.336~~1.694	~~6.361~~6.719	~~0.2091~~0.2209
Commodity								
Maximum	¢	1.04	0.03	1.04	0.00	0.00	2.11	2.11
Minimum	¢	1.04	0.03	1.04	0.00	0.00	2.11	2.11
Overrun								
Maximum	¢	16.73	0.70	1.25	-0.05	~~4.39~~5.57	~~23.02~~24.20	~~23.02~~24.20
Minimum	¢	1.04	0.03	1.04	0.00	0.00	2.11	2.11

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.

[illegible]

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 [illegible] percent undivided interest in Owner-Operator's line [illegible] [illegible] transmission pipeline and appurtenant facilities (the "Pipeline"). The Pipeline is [illegible] 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 [illegible] 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 [illegible], 2005, as amended by that certain Amendment to Operating Agreement dated as of April [illegible], 2008 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 $[illegible], and a Flat Monthly Charge for Commercial Services equal to $[illegible]. [illegible] the Flat Monthly Charge for Operational Services is recovered by Co-Owner through Co-Owner's tariff rates for [illegible] with the FERC. [illegible] of the Flat Monthly Charge for Operational Services and the [illegible] Flat Monthly Charge for Commercial Services [illegible] being referred to herein as the "Incremental Monthly Charge") 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 directly 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 OKY 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-Owner and OKY to invoice Co-Owner and OKY in a different manner, Owner-Operator shall invoice OKY each month for (a) [illegible] of the Firm Monthly Charge for Operational Requirements (b) all of [illegible] of the Firm Monthly Charge for the Commercial Services. Owner-Operator agrees to accept payment of all amounts from OKY 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 Firm Monthly Charges under the Operating Agreement, including, without limitation, the Incremental Monthly Charges that shall be invoiced to OKY under this Agreement. In the event OKY 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, OKY 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 OKY or Co-Owner.

3. Payment by OKY. During the Term, OKY 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 [illegible] with respect to such Incremental Monthly Charges. OKY reserves the right to assert all defenses, counterclaims and offsets that Co-Owner could assert under the [illegible] Operating Agreement. OKY's [illegible] obligations under this Agreement are specifically limited to [illegible] of the Incremental Monthly Charges as and when the same become due under the Operating Agreement and OKY 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.

4. 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

To Owner-Operator:

Columbia Gas Transmission, LLC
151 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: [signature]
Name: Stanley G. Chapman, III
Its: Executive Vice President and Chief Commercial Officer

COLUMBIA GAS OF KENTUCKY, INC.

By: [signature]
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	1.6247	3.7773	8.9685	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	1.6247	3.7773	8.4201	I
Next 350 Mcf per billing period	2.3295	1.6247	3.7773	7.7315	I
Next 600 Mcf per billing period	2.2143	1.6247	3.7773	7.6163	I
Over 1,000 Mcf per billing period	2.0143	1.6247	3.7773	7.4163	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		3.7773 [2/]	4.4058	I
Next 70,000 Mcf per billing period	0.3737		3.7773 [2/]	4.1510	I
Over 100,000 Mcf per billing period	0.3247		3.7773 [2/]	4.1020	I
Firm Service Demand Charge					
Demand Charge times Daily Firm					
Volume (Mcf) in Customer Service Agreement		7.0529		7.0529	I
RATE SCHEDULE IUS					
Customer Charge per billing period	567.40			567.40	
Delivery Charge per Mcf					
For All Volumes Delivered	1.1544	1.6247	3.7773	6.5564	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 $4.4990 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 30, 2018

DATE EFFECTIVE March 1, 2018 (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		7.0529		7.0529	
Standby Service Commodity Charge per Mcf			3.7773	3.7773	
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		0.0216		0.0216	R
RATE SCHEDULE MLDS					
Customer Charge per billing period				255.90	
Delivery Charge per Mcf				0.0858	
Banking and Balancing Service					
Rate per Mcf		0.0216		0.0216	R

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 30, 2018

DATE EFFECTIVE March 1, 2018 (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	$0.7686
RATE SCHEDULE SVAS	
Balancing Charge – per Mcf	$1.4128

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 30, 2018

DATE EFFECTIVE March 1, 2017 (Unit 1 March)

ISSUED BY Herbert A. Miller Jr.

TITLE President