Columbia Gas of Kentucky, Inc.
Case No. 2021-00183
Standard Filing Requirements
5/28/2021
Volume 1 of 9

Tab	Filing Requirement	Description	Responsible Witness(es)
1	807 KAR 5:001 Section 14-(1)	Name, Address, Facts	Kimra H. Cole
2	807 KAR 5:001 Section 14-(2)	Corp. - Incorporation, Good Standing	Kimra H. Cole
3	807 KAR 5:001 Section 14-(3)	LLC - Organized, Good Standing	Not Applicable
4	807 KAR 5:001 Section 14-(4)	LP - Agreement	Not Applicable
5	807 KAR 5:001 Section 16-(1)(b)1	Reason for Rate Adjustment	Kimra H. Cole
6	807 KAR 5:001 Section 16-(1)(b)2	Certificate of Assumed Name	Kimra H. Cole
7	807 KAR 5:001 Section 16-(1)(b)3	Proposed Tariff	Judy M. Cooper
8	807 KAR 5:001 Section 16-(1)(b)4	Proposed Tariff Changes	Judy M. Cooper
9	807 KAR 5:001 Section 16-(1)(b)5	Statement about Customer Notice	Kimra H. Cole
10	807 KAR 5:001 Section 16-(2)	Notice of Intent	Kimra H. Cole
11	807 KAR 5:001 Section 16-(6)(a)	Financial Data	Jeffery T. Gore, Jennfier Harding, Chun-Yi Lai, Judith L. Siegler, Susanne M. Taylor
12	807 KAR 5:001 Section 16-(6)(b)	Forecasted Adjustments	Jeffery T. Gore, Jennfier Harding, Chun-Yi Lai, Judith L. Siegler, Susanne M. Taylor
13	807 KAR 5:001 Section 16-(6)(c)	Capital, Net Investment Rate Base	Jeffery T. Gore
14	807 KAR 5:001 Section 16-(6)(d)	No Revisions to Forecast	Kimra H. Cole
15	807 KAR 5:001 Section 16-(6)(e)	Alternative Forecast	Kimra H. Cole
16	807 KAR 5:001 Section 16-(6)(f)	Reconciliation of Rate Base and Capital	Jeffery T. Gore
17	807 KAR 5:001 Section 16-(7)(a)	Testimony	Kimra H. Cole
18	807 KAR 5:001 Section 16-(7)(a)	Testimony	David A. Roy
19	807 KAR 5:001 Section 16-(7)(a)	Testimony	Judy M. Cooper
20	807 KAR 5:001 Section 16-(7)(a)	Testimony	Jeffery T. Gore

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 14-(1)

Description of Filing Requirement:

Each application shall state the full name, mailing address, and electronic mail address of the applicant, and shall contain fully the facts on which the application is based, with a request for the order, authorization, permission, or certificate desired and a reference to the particular law requiring or providing for the information.

Response:

Please see Application Paragraph 9.

Responsible Witness:

Kimra H. Cole

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 14-(2)

Description of Filing Requirement:

If a corporation, the applicant shall identify in the application the state in which it is incorporated and the date of its incorporation, attest that it is currently in good standing in the state in which it is incorporated, and, if it is not a Kentucky corporation, state if it is authorized to transact business in Kentucky.

Response:

Please refer to the attachment and Application Paragraph 11.

Responsible Witness:

Kimra H. Cole

Commonwealth of Kentucky
Michael G. Adams, Secretary of State

Michael G. Adams
Secretary of State
P. O. Box 718
Frankfort, KY 40602-0718
(502) 564-3490
http://www.sos.ky.gov

Certificate of Existence

Authentication number: 245844
Visit https://web.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

I, Michael G. Adams, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

COLUMBIA GAS OF KENTUCKY, INC.

is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is October 11, 1905 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that Articles of Dissolution have not been filed; and that the most recent annual report required by KRS 14A.6-010 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 27th day of April, 2021, in the 229th year of the Commonwealth.

COMMONWEALTH OF KENTUCKY
OFFICE OF SECRETARY OF STATE

Michael G. Adams

Michael G. Adams
Secretary of State
Commonwealth of Kentucky
245844/0010555

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 14-3

Description of Filing Requirement:

If a limited liability company, the applicant shall identify in the application the state in which it is organized and the date on which it was organized, attest that it is in good standing in the state in which it is organized, and, if it is not a Kentucky limited liability company, state if it is authorized to transact business in Kentucky.

Response:

Not applicable.

Responsible Witness:

Not applicable.

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 14-(4)

Description of Filing Requirement:

If the applicant is a limited partnership, a certified copy of its limited partnership agreement and all amendments, if any, shall be annexed to the application, or a written statement attesting that its partnership agreement and all amendments have been filed with the commission in a prior proceeding and referencing the case number of the prior proceeding.

Response:

Not Applicable.

Responsible Witness:

Not Applicable.

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(1)(b)1

Description of Filing Requirement:

A statement of the reason the adjustment is required.

Response:

Please refer to the testimony of Kimra H. Cole and Application Paragraph 13.

Responsible Witness:

Kimra H. Cole

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(1)(b)2

Description of Filing Requirement:

A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that such a certificate is not necessary.

Response:

A certificate of assumed name is not necessary.

Responsible Witness:

Kimra H. Cole

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(1)(b)3

Description of Filing Requirement:

New or revised tariff sheets, if applicable in a format that complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed.

Response:

Please see attached. In addition, the proposed tariffs have been included as an attachment, Schedule L, under 807 KAR 5:001 Section 16-(8)(l) located at Tab 81.

Responsible Witness:

Judy M. Cooper

INDEX (Continued)

DATE OF ISSUE: May 28, 2021

DATE EFFECTIVE: June 28, 2021

ISSUED BY: /s/ Kimra H. Cole

TITLE: President & Chief Operating Officer

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[3/] $	
RATE SCHEDULE GSR					
Customer Charge per billing period	29.20			29.20	I
Delivery Charge per Mcf	4.2263[3/]	2.1785	2.2204	8.6252	I
RATE SCHEDULE GSO					
Commercial or Industrial					
Customer Charge per billing period	87.15			87.15	I
Delivery Charge per Mcf -					
First 50 Mcf or less per billing period	3.5622[3/]	2.1785	2.2204	7.9611	I
Next 350 Mcf per billing period	2.7494[3/]	2.1785	2.2204	7.1483	I
Next 600 Mcf per billing period	2.6135[3/]	2.1785	2.2204	7.0124	I
Over 1,000 Mcf per billing period	2.3782[3/]	2.1785	2.2204	6.7771	I
RATE SCHEDULE IS					
Customer Charge per billing period	4151.00			4151.00	I
Delivery Charge per Mcf					
First 30,000 Mcf per billing period	0.7701[3/]		2.2204[2/]	2.9905	I
Next 70,000 Mcf per billing period	0.4579[3/]		2.2204[2/]	2.6783	I
Over 100,000 Mcf per billing period	0.3975[3/]		2.2204[2/]	2.6179	I
Firm Service Demand Charge					
Demand Charge times Daily Firm					
Volume (Mcf) in Customer Service Agreement		11.9517		11.9517	
RATE SCHEDULE IUS					
Customer Charge per billing period	991.20			991.20	I
Delivery Charge per Mcf					
For All Volumes Delivered	1.3261[3/]	2.1785	2.2204	5.7250	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 $ 4.9563 per Mcf only for those months of the prior twelve months during which they were served under Rate Schedule SVGTS. R

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

3/ The Delivery Charge will be adjusted at billing by the Tax Act Adjustment Factor set forth on Sheet 7a.

DATE OF ISSUE	May 28, 2021
DATE EFFECTIVE	June 28, 2021
ISSUED BY	/s/ Kimra H. Cole
TITLE	President & Chief Operating Officer

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[3/] $	
RATE SCHEDULE SS					
Standby Service Demand Charge per Mcf					
Demand Charge times Daily Firm					
Volume (Mcf) in Customer Service Agreement		11.9517		11.9517	
Standby Service Commodity Charge per Mcf			2.2204	2.2204	R
RATE SCHEDULE DS					
Customer Charge per billing period [2/]				4151.00	I
Customer Charge per billing period (GDS only)				87.15	
Customer Charge per billing period (IUDS only)				991.20	
Delivery Charge per Mcf[2/]					
First 30,000 Mcf	0.7701[3/]			0.7701	
Next 70,000 Mcf	0.4579[3/]			0.4579	
Over 100,000 Mcf	0.3975[3/]			0.3975	
– Grandfathered Delivery Service					
First 50 Mcf or less per billing period				3.5622[3/]	
Next 350 Mcf per billing period				2.7494[3/]	
Next 600 Mcf per billing period				2.6135[3/]	
All Over 1,000 Mcf per billing period				2.3782[3/]	
– Intrastate Utility Delivery Service					
All Volumes per billing period				1.3261[3/]	
Banking and Balancing Service					
Rate per Mcf		0.0469		0.0469	
RATE SCHEDULE MLDS					
Customer Charge per billing period				282.20	I
Delivery Charge per Mcf				0.0946	I
Banking and Balancing Service					
Rate per Mcf		0.0469		0.0469	

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.
3/ The Delivery Charge will be adjusted at billing by the Tax Act Adjustment Factor set forth on Sheet 7a.

DATE OF ISSUE May 28, 2021

DATE EFFECTIVE June 28, 2021

ISSUED BY /s/ Kimra H. Cole

TITLE President & Chief Operating Officer

COLUMBIA GAS OF KENTUCKY, INC.

CURRENTLY EFFECTIVE BILLING RATES
(Continued)

RATE SCHEDULE SVGTS	**Base Rate Charge** $
General Service Residential (SGVTS GSR)	
Customer Charge per billing period	29.20
Delivery Charge per Mcf	4.2263 2/
General Service Other - Commercial or Industrial (SVGTS GSO)	
Customer Charge per billing period	87.15
Delivery Charge per Mcf -	
First 50 Mcf or less per billing period	3.5622 2/
Next 350 Mcf per billing period	2.7494 2/
Next 600 Mcf per billing period	2.6135 2/
Over 1,000 Mcf per billing period	2.3782 2/
Intrastate Utility Service	
Customer Charge per billing period	991.20
Delivery Charge per Mcf	$ 1.3261 2/

	Billing Rate
Actual Gas Cost Adjustment 1/	
For all volumes per billing period per Mcf	$(0.5834)

RATE SCHEDULE SVAS

Balancing Charge – per Mcf	$1.6245

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.

2/ The Delivery Charge will be adjusted at billing by the Tax Act Adjustment Factor set forth on Sheet 7a.

DATE OF ISSUE	May 28, 2021
DATE EFFECTIVE	June 28, 2021
ISSUED BY	/s/ Kimra H. Cole
TITLE	President & Chief Operating Officer

TAX ACT ADJUSTMENT FACTOR

(TAAF) T

APPLICABILITY

Applicable in the entire service territory of Company.

AVAILABILITY

To implement the effects of future Federal and or Kentucky income tax reform, the Tax Act Adjustment Factor is available to customers as of the effective date of an increase of decrease of the federal and/or Kentucky income tax rate based upon the applicable Rate Schedule as set forth below. The applicable Tax Act Adjustment Factor shall be applied at billing to the volumetric Delivery Charge. N N N

CALCULATION OF THE TAX ACT ADJUSTMENT FACTOR (TAAF) N

The TAAF is the difference between the income tax expense included in the revenue requirement approved by the Commission in the Company's most recent base rate proceeding and the calculated income tax expense had the increase or decrease of the Federal and or Kentucky income tax rate been in effect during the test year after applying the gross conversion factor. The allocation of the TAAF shall be based on the revenue distribution approved by the Commission.

RATE PER MCF	EFFECTIVE DATE MONTH,YEAR	
Rate Schedules GSR and SVGTS Residential - GSR	($0.0000) I	D
Rate Schedules GSO and SVGTS Commercial or Industrial GSO	($0.0000) I	T D
Rate Schedule IS	($0.0000) I	D
Rate Schedule IUS and SVGTS IUS	($0.0000) I	T,I
Rate Schedule DS[1/]	($0.0000) I	D
Rate Schedule GDS	($0.0000) I	D
Rate Schedule IUDS	($0.0000) I	D

1/ Excluding customers subject to the Flex Provisions of Rate Schedule DS

GENERAL SERVICE (GS) AND GENERAL PROPANE SERVICE (GPS)
SALES SERVICE RATE SCHEDULES

APPLICABILITY

Entire service territory of Company. See Sheet 8 for a list of communities.

AVAILABILITY OF SERVICE

Available to residential, commercial and industrial sales service customers.

See Sheet Nos. 53 through 56 for Temporary Volumetric Limitations and Curtailment provisions for all purposes.

BASE RATES

Residential (GSR)		
Customer Charge per billing period	@ $29.20	I
Delivery Charge per Mcf	@ $4.2263 per Mcf	I
Commercial or Industrial (GSO)		
Customer Charge per billing period	@ $87.15	I
Delivery Charge per Mcf -		
First 50 or less Mcf per billing period	@ $3.5622 per Mcf	I
Next 350 Mcf per billing period	@ $2.7494 per Mcf	I
Next 600 Mcf per billing period	@ $2.6135 per Mcf	I
Over 1,000 Mcf per billing period	@ $2.3782 per Mcf	I

MINIMUM CHARGE

The minimum charge per billing period shall be the applicable Customer Charge. If the meter reading or calculated consumption for the billing period is greater than zero then the minimum charge shall be increased by the Delivery Charge for a minimum of one Mcf per billing period.

GAS COST ADJUSTMENT

Gas sold under this rate schedule and rates as prescribed herein are subject to a Gas Cost Adjustment as stated on currently effective Sheet Nos. 48 through 51 of this tariff which are hereby incorporated into this rate schedule.

The charges set forth herein, exclusive of those pertaining to the minimum charge, shall be subject to a Gas Cost Adjustment, as shown on Sheet 5 of this tariff.

INTERRUPTIBLE SERVICE (IS)
SALES SERVICE RATE SCHEDULE
(Continued)

CHARACTER OF SERVICE (continued)

provision that the Customer may not concurrently contract with the Company for Delivery Service under Rate DS. The full sales agreement is subject to a minimum contract period of one (1) year as set forth in the General Terms, Conditions, Rules and Regulations, Section 34.

BASE RATES

Customer Charge
$4,151.00 per billing period I

Delivery Charge per Mcf -

First 30,000 Mcf per billing period	@ $ 0.7701 per Mcf	I
Next 70,000 Mcf per billing period	@ $ 0.4579 per Mcf	I
Over 100,000 Mcf per billing period	@ $ 0.3975 per Mcf	I

MINIMUM CHARGE

The minimum charge each billing period for gas delivered or the right of the Customer to receive same shall be the sum of the Customer Charge of $4,151.00 , **plus** the Customer Demand Charge as contracted for under Firm Service. (Daily Firm Volume as specified in the Customer's service agreement multiplied by the demand rate (See Sheet No. 5). I

In the event of monthly, seasonal or annual curtailment due to gas supply shortage, the demand charge shall be waived when the volume made available is less than 110% of the Daily Firm Volume multiplied by thirty (30). In no event will the minimum charge be less than the Customer charge.

If the delivery of firm volumes of gas by Company is reduced, due to peak day interruption in the delivery of gas by Company or complete or partial suspension of operations by Customer resulting from force majeure, the Minimum Charge shall be reduced in direct proportion to the ratio which the number of days of curtailed service and complete or partial suspension of Customer's operation bears to the total number of days in the billing period. Provided, however, that in cases of Customer's force majeure, the Minimum Charge shall not be reduced to less than the Customer Charge.

GAS COST ADJUSTMENT

Except as otherwise provided herein, gas sold under this rate schedule and rates as prescribed herein are subject to the Gas Cost Adjustment, including the Commodity and Demand components, as stated on currently effective Sheet Nos. 48 through 51 herein, which are hereby incorporated into this rate schedule.

For a Customer who enters into a full sales agreement under this rate schedule after September 1, 1995, the Gas Cost Adjustment shall consist of the Expected Commodity Cost of Gas, as defined in paragraph 1 (a) of Sheet No. 48 herein, and shall not be adjusted to reflect the supplier Refund Adjustment (RA), the Actual Cost Adjustment (ACA), or the Balancing Adjustment (BA) for a period of one year from the effective date of the Customer's agreement. At the end of that one-year period, any gas purchased by the Customer under that agreement shall be subject to the Commodity Cost of Gas, including all appropriate adjustments, as defined in Sheet Nos. 48 and 49.

DATE OF ISSUE May 28, 2021

DATE EFFECTIVE June 28, 2021

ISSUED BY /s/ Kimra H. Cole

TITLE President & Chief Operating Officer

INTRASTATE UTILTY SALES SERVICE (IUS)
RATE SCHEDULE

APPLICABILITY

Entire service territory of Company. See Sheet No. 8 for a list of communities.

AVAILABILITY OF SERVICE

Available for service to intrastate utilities purchasing gas for resale for consumption solely within the Commonwealth of Kentucky when:

(1) Company's existing facilities have sufficient capacity and gas supply to provide the quantities of gas requested by said Customer, and

(2) Customer has executed a Sales Agreement with Company specifying, among other things, a Maximum Daily Volume.

CHARACTER OF SERVICE

Gas delivered by Company to Customer under this rate schedule shall be firm and shall not be subject to curtailment or interruption, except as provided in Section 32 of the General Terms, Conditions, Rules and Regulations.

BASE RATE

Customer Charge per billing period	$991.20	I
Delivery Charge per Mcf –		
For all gas delivered each billing period	$1.3261per Mcf.	I

MINIMUM CHARGE

The minimum charge shall be the Customer Charge.

GAS COST ADJUSTMENT

Gas sold under this rate schedule and rates as prescribed herein are subject to a Gas Cost Adjustment as stated on currently effective Sheet Nos. 48 through 51, which are hereby incorporated into this rate schedule.

The charges set forth herein, exclusive of those pertaining to the Customer Charge, shall be subject to a Gas Cost Adjustment as shown on Sheet No. 5 of this tariff.

ADJUSTMENTS AND RIDERS

Customers served under this Rate Schedule are subject to the currently effective Adjustments and Riders as prescribed on the Tariff Sheets set forth below and incorporated into this Rate Schedule:
Tax Act Adjustment Factor – Sheet No. 7a
Rider for Natural Gas Research & Development – Sheet No. 51c
Rider SMRP – Sheet No. 58 T

DATE OF ISSUE	May 28, 2021
DATE EFFECTIVE	June 28, 2021
ISSUED BY	/s/ Kimra H. Cole
TITLE	President & Chief Operating Officer

SMALL VOLUME GAS TRANSPORTATION SERVICE
(SVGTS)
RATE SCHEDULE (Continued)

CHARACTER OF SERVICE

Service provided under this schedule shall be considered firm service.

DELIVERY CHARGE

The Delivery Charge shall be the Base Rate Charges for the applicable Rate Schedule as set forth below:

General Service Residential (SVGTS GSR)

Customer Charge per billing period	$29.20	I
Delivery Charge	$4.2263 per Mcf	I

General Service Other – Commercial or Industrial (SVGTS GSO)

Customer Charge per billing period	$87.15	I
First 50 Mcf or less per billing period	$3.5622 per Mcf	I
Next 350 Mcf per billing period	$2.7494 per Mcf	I
Next 600 Mcf per billing period	$2.6135 per Mcf	I
Over 1,000 Mcf per billing period	$2.3782 per Mcf	I

Intrastate Utility Service

Customer Charge per billing period	$991.20	I
Delivery Charge per Mcf	$1.3261	I

ADJUSTMENTS AND RIDERS

Customers served under this Rate Schedule are subject to the currently effective Adjustments and Riders as prescribed on the Tariff Sheets set forth below and incorporated into this Rate Schedule:
Tax Act Adjustment Factor – Sheet 7a
Weather Normalization Adjustment – Sheet 51a
Energy Assistance Program Surcharge – Sheet No. 51b (Applies to Residential Customers only)
Rider for Natural Gas Research & Development – Sheet No. 51c
Energy Efficiency Conservation Rider – Sheets 51d – 51h (Applies to Residential and Commercial Customers only)
SMRP Rider – Sheet No. 58 T

DELIVERY SERVICE (DS)
TRANSPORTATION SERVICE RATE SCHEDULE

APPLICABILITY

Entire service territory of Company. See Sheet No. 8 for a list of communities.

AVAILABILITY

This rate schedule is available to any Customer throughout the territory served by Company provided:

(1) Customer has executed a Delivery Service Agreement with Company, and
(2) Customer has normal annual requirements of not less than 25,000 Mcf at any delivery point, and
(3) Company will not be required to deliver on any day more than the lesser of (i) a quantity of gas equivalent to Customer's Maximum Daily Volume specified in its Delivery Service Agreement; (ii) the quantity of gas scheduled and confirmed to be delivered into the Company's distribution facilities on behalf of the Customer on that day plus applicable Standby Sales; or (iii) the Customer's Authorized Daily Volume, and
(4) On an annual basis, a Customers Maximum Daily Volume and Annual Transportation Volume will be automatically adjusted to the Customers actual Maximum Daily Volume and actual Annual Transportation Volume based on the Customers highest daily and annual volumetric consumption experienced during the preceding 12-month periods ending with March billings. Upon a Customers request, the Company shall have the discretion to further adjust a Customers Maximum Daily Volume and Annual Transportation Volume for good cause shown.

Customers Grandfathered ("GDS") This rate schedule is also available to customers with normal annual requirements of less than 25,000 Mcf but not less than 6,000 Mcf, at any delivery point taking service under a contract with Company for delivery service executed prior to April 1, 1999.

Intrastate Utility ("IUDS") This rate schedule is also available to intrastate utilities for transportation and consumption solely within the Commonwealth of Kentucky.

BASE RATE

Customer Charge per billing period	$4,151.00	I
Customer Charge per billing period (GDS only)	$87.15	I
Customer Charge per billing period (IUDS only)	$991.20	I
Delivery Charge per Mcf -		
First 30,000 Mcf	$0.7701 per Mcf for all gas delivered each billing month	I
Next 70,000 Mcf	$0.4579 per Mcf for all gas delivered each billing month	I
Over 100,000 Mcf	$0.3975 per Mcf for all gas delivered each billing month	I
Grandfathered Delivery Service		
First 50 Mcf per billing period	$3.5622	I
Next 350 Mcf per billing period	$2.7494	I
Next 600 Mcf per billing period	$2.6135	I
All Over 1,000 Mcf per billing period	$2.3782	I
Intrastate Utility Delivery Service		
All volumes per billing period	$1.3261	I
Banking and Balancing Service		
Rate per Mcf	See Sheet No. 6	

DATE OF ISSUE May 28, 2021

DATE EFFECTIVE June 28, 2021

ISSUED BY /s/ Kimra H.Cole

TITLE President & Chief Operating Officer

MAIN LINE DELIVERY SERVICE (MLDS)
RATE SCHEDULE

APPLICABILITY

Entire service territory of Company. See Sheet No. 8 for a list of communities.

AVAILABILITY

This rate schedule is available to any Customer throughout the territory served by Company provided:

(1) Customer has executed a Delivery Service Agreement with Company, and
(2) Customer has normal annual requirements of not less than 25,000 Mcf at any delivery point, and
(3) Customer is connected directly through a dual-purpose meter to facilities of an interstate pipeline supplier of Company, and
(4) Company will not be required to deliver on any day more than the lesser of: (i) a quantity of gas equivalent to Customer's Maximum Daily Volume specified in its Delivery Service Agreement; (ii) the quantity of gas scheduled and confirmed to be delivered into the Company's distribution facilities on behalf of the Customer on that day plus applicable Standby Sales; or (iii) the Customer's Authorized Daily Volume, and
(5) On an annual basis, a Customers Maximum Daily Volume and Annual Transportation Volume will be automatically adjusted to the Customers actual Maximum Daily Volume and actual Annual Transportation Volume based on the Customers highest daily and annual volumetric consumption experienced during the preceding 12-month periods ending with March billings. Upon a Customers request, the Company shall have the discretion to further adjust a Customers Maximum Daily Volume and Annual Transportation Volume for good cause shown.

RATE

The transportation rate shall be $0.0946 per Mcf for all gas delivered each month. I

CUSTOMER CHARGE

The customer charge shall be $282.20 per account each billing period. I

BANKING AND BALANCING SERVICE

The rate for the Banking and Balancing Service is set forth on Sheet No. 6. This rate represents the current storage cost to the Company to provide a 'bank tolerance' to the Customer of five percent (5%) of the Customer's Annual Transportation Volume. The calculation of the Banking and Balancing Service rate is set forth in the Company's Gas Cost Adjustment.

The Banking and Balancing Service rate is subject to flexing as provided in the Flex Provision of this rate schedule. Refer to Sheet No. 91, Banking and Balancing Service, for the terms and conditions of the Balancing and Banking Service.

ADJUSTMENTS AND RIDERS

Customers served under this Rate Schedule are subject to the currently effective Adjustments and Riders as prescribed on the Tariff Sheets set forth below and incorporated into this Rate Schedule:

Rider for Natural Gas Research & Development –Sheet No. 51c

NOMINATION AND SCHEDULING OF TRANSPORTATION DELIVERIES

All transportation deliveries must be nominated and scheduled through the Company's internet based nomination system. Any customer that transports gas under this schedule may elect to have its marketer or agent make the required nominations, or the Customer may elect to connect to make daily nominations of Delivery Service gas.

SMRP RIDER
SAFETY MODIFICATION AND REPLACEMENT PROGRAM RIDER

APPLICABILITY

Applicable to all customers receiving service under the Company's Rate Schedules GS, IS, IUS, SVGTS, DS and SAS.

CALCULATION OF SAFETY MODIFICATION AND REPLACEMENT RIDER REVENUE REQUIREMENT

The SMRP Rider Revenue Requirement includes the following:

a. SMRP-related Plant In-Service not included in base gas rates minus the associated SMRP-related accumulated depreciation and accumulated deferred income taxes;
b. Retirement and removal of plant related to SMRP construction;
c. The rate of return on the net rate base is the overall rate of return on capital authorized in the Company's latest base gas rate case, grossed up for federal and state income taxes;
d. Depreciation expense on the SMRP = related Plant In-Service less retirement and removals;
e. Property taxes related to the SMRP; and
f. Reduction for savings in Account No. 887 – Maintenance of Mains,

SAFETY MODIFICATION AND REPLACEMENT PROGRAM FACTORS

All customers receiving service under Rate Schedules GSR, GSO, IS, IUS, SVGTS, DS, GDS and SAS shall be assessed a monthly charge in addition to the Customer Charge component of their applicable rate schedule that will enable the Company to complete the safety modification and replacement program.

Rider SMRP will be updated annually in order to reflect the expected impact on the Company's revenue requirements of forecasted net plant additions and subsequently adjusted to true up the actual costs with the projected costs. A filing to update the projected costs for the upcoming calendar year will be submitted annually by October 15 to become effective with meter readings on and after the first billing cycle of January. The allocation of the program costs shall be based on the revenue distribution approved by the Commission. Company will submit a balancing adjustment annually by March 31 to true-up the actual costs, as offset by operations and maintenance expense reductions, during the most recent twelve months ended December with the projected program costs for the same period. The balancing adjustment true-up to the rider will become effective with meter readings on and after the first billing cycle of June.

The charges for the respective gas service schedules effective June 28, 2021 are: T

Rate GSR, Rate SVGTS - Residential Service	$0.00	R
Rate GSO, Rate GDS, Rate SVGTS - Commercial or Industrial Service	$0.00	R
Rate IUS, Rate IUDS	$0.00	R
Rate IS, Rate DS[1/], Rate SAS	$0.00	R

1/ - Excluding customers subject to Flex Provisions of Rate Schedule DS

DATE OF ISSUE: May 28, 2021

DATE EFFECTIVE: June 28, 2021

ISSUED BY: /s/ Kimra H. Cole

TITLE: President & Chief Operating Officer

GENERAL TERMS, CONDITIONS, RULES AND REGULATIONS
(Continued)

18. QUALITY

Processing. The gas delivered shall be natural gas; provided, however, that:

(a) Company may extract or permit the extraction of moisture, helium, natural gasoline, butane, propane or other hydrocarbons (except methane) from said natural gas, or may return thereto any substance extracted from it. Company, in order to conserve and utilize other available gases, may blend such gases with said natural gas; provided, however, that such blending shall not extend to a degree which, in Customer's judgment reasonably exercised, would materially affect the utilization of the gas delivered.

(b) Company may subject or permit the subjection of said natural gas to compression, cooling, cleaning or other processes to such an extent as may be required in its transmission from the source thereof to the point or points of delivery.

Heat Content. The Total Heating Value of the gas shall be determined by taking samples of the gas at the point(s) of receipt at such reasonable times as may be designated by Company. The Btu content per cubic foot shall be determined by an accepted type of calorimeter or other suitable instrument for a cubic foot of gas at a temperature of sixty (60) degrees Fahrenheit when saturated with water vapor and at a pressure of 14.73 psia, or from recording calorimeters located at such place or places as may be selected by Company. Such calorimeters shall be periodically checked, using a reference sample of gas of known heating value, or such other method as may be mutually agreed upon. Customer shall not be required to accept natural gas having a total heating value of less than nine hundred fifty (950) Btu per cubic foot, but acceptance by Customer shall not relieve Company of its obligation to supply natural gas having the said average total heating value of one thousand (1,000) Btu per cubic foot. N,D D

The unit of volume for the purpose of determining total heating value shall be one (1) cubic foot of gas saturated with water vapor at a temperature of sixty degree (60°) Fahrenheit and an absolute pressure equivalent to thirty (30) inches of mercury at thirty-two degrees (32°) Fahrenheit and under standard gravity (32.174 ft. per second per second).

Freedom From Objectional Matter. The gas delivered shall be commercially free from oil, water, air, salt, dust, gum, gum-forming constituents, harmful or noxious vapors, or other solid or liquid matter which might interfere with its merchantability or cause injury to or interference with proper operation of the lines, regulators, meters, and other equipment of Company or its Customers. N N

D

DATE OF ISSUE:	May 28, 2021
DATE EFFECTIVE:	June 28, 2021
ISSUED BY:	/s/ Kimra H. Cole
TITLE:	President & Chief Operating Officer

GENERAL TERMS, CONDITIONS, RULES AND REGULATIONS
(Continued)

18. QUALITY - (Continued)

Freedom From Objectional Matter. - (Continued)

____To assure that the gas delivered by Customer/Supplier to Company conforms to the quality specifications of this Section, Customer's/Supplier's gas shall be analyzed at the point(s) of receipt from time-to-time as Company deems necessary. The gas delivered shall conform to the following gas quality specifications N

Gas Quality Specifications[1]

Gas Quality Parameter Specification	Low	High
Heat Content (Btu/scf)[2]	967	1110
Wobbe Number (+/- 6% from 1300)	1222	1378
Water Vapor Content (lbs./MM scf)		< 7
Product Gas Mercaptans (ppmv, does not include gas odorants)		< 1
Hydrocarbon Dew Point, (°F) CHDP		15
Hydrogen Sulfide (grain/100 scf)		0.25
Total Sulfur (grain/100 scf)		20
Total Diluent Gases including the following individual constituent limits: Carbon Dioxide (CO_2) 2% max Nitrogen (N) 4% max Oxygen (O_2) 1% max		5%
Hydrogen		0.3%
Total Bacteria[3] (If no filter installed, then limit is $6.4x10^7$ per 100 scf total bacteria)	Comm Free (≤ 0.2 microns)	
Mercury	Comm Free (< 0.06 $\mu g/m^3$)	
Other Volatile Metals (Lead)	Comm Free (< 213 $\mu g/m^3$)	
Siloxanes as Octamethylcyclotetrasiloxane[4]	Comm Free (-< 0.5 mg Si/m^3)	
Ammonia	Comm Free (< 10 ppmv)	
Non-Halogenated Semi-Volatile and Volatile Compounds	Comm Free (< 500 ppmv)	
Halocarbons (total measured halocarbons)[5]	< 3 ppmv	
Aldehyde/Ketones	Aldehydes/Ketones must be at a level that does not unreasonably interfere with odorization of Company's gas.	
PCBs/Pesticides	Comm Free (< 1 ppbv)	

[1] For purposes of this Tariff, "Commercially Free" is defined as "Not Detectable" relative to typical pipeline gas flowing at the interconnect location that results in non-pipeline and/or RNG gas being compositionally equivalent to Company's flowing supplies. The analytical method, associated detection threshold, and testing facility shall be determined by the Company. Periodic testing will be required where potential Constituents of Concern are reasonably expected.

[2] Higher Heating Value is dry, @ 14.73 psia 60°F.

[3] An acceptable alternative to Total Bacteria testing would be to include installation of a 0.2 micron particulate filter, coupled with appropriate filter maintenance practices. Initial start-up testing may include filter effectiveness analysis. Customer/Supplier shall be responsible for all costs associated with acceptable alternatives, including, but not limited to, initial start-up testing.

GENERAL TERMS, CONDITIONS, RULES AND REGULATIONS
(Continued)

18. QUALITY - (Continued)

Freedom From Objectional Matter. - Gas Quality Specifications (Continued) N

[4] Historical testing and data presented in this document include a siloxane detection threshold of <0.5mg Si/m3. Analytical methods have recently been improved resulting in a reduced detection threshold of <0.1mg Si/m3. Due to specific limitations of certain identified applications within an affected zone of influence, Company and Customer/Supplier may agree upon a reduced threshold.
[5] Company may refuse to accept gas containing lower levels of halocarbons if Company reasonably determines that such gas is causing harm to its facilities or the gas-burning equipment of its customers, or is adversely affecting the operation of such facilities. In addition, Company and Customer/Supplier may agree upon a different specification for halocarbons, provided that Customer/Supplier has demonstrated, to the reasonable satisfaction of Company, that non-pipeline natural gas and/or RNG meeting the agreed-upon specification will not adversely affect (a) the quality of public utility service provided by Company; (b) the operation or Company's equipment; or (c) the operation of the gas-burning equipment of Company's customers.

As used in the foregoing table, "Btu" means British thermal unit; "scf" means standard cubic foot; "MM" means one million; "CHDP" means cricondentherm hydrocarbon dew point; "ppmv" means parts per million by volume; and "ppbv" means parts per billion by volume. "RNG" or "Renewable Natural Gas" means gas, consistently primarily of methane, which (1) is derived from biogas produced by landfills, animal farms, wastewater treatment plans, or other sources, and (2) is subsequently processed by removing carbon dioxide, nitrogen, and other constituents in order to convert the biogas into pipeline-compatible gaseous fuel.

The Total Heating Value of the gas shall be determined by taking samples of the gas at the point(s) of receipt at such reasonable times as may be designated by Company. The Btu content per cubic foot shall be determined by an accepted type of calorimeter or other suitable instrument for a cubic foot of gas at a temperature of sixty (60) degrees Fahrenheit when saturated with water vapor and at a pressure of 14.73 psia. The Btu determination designated by Company shall be made by Company at its expense. Any additional Btu determinations requested by Customer/Supplier shall be at the expense of the requesting Customer/Supplier.

Company may, on a not-unduly discriminatory basis, accept volumes of gas, including renewable natural gas, that fail to meet the quality specifications set forth in this tariff section, if Company determines that it can do so without adversely affecting (1) system operations; (2) the operation of the Company's equipment; (3) the operation of gas-burning equipment of Company's other customers; or (4) the quality of public utility service provided by Company. In deciding whether to accept such volumes of gas, the Company shall consider, without limitation, (1) which specifications are not being met; (2) the sensitivity of customer equipment and potential impact on such equipment; (3) Customer's plan to improve gas quality; (4) the effect on system supply; (5) interchangeability; (6) the anticipated duration of the quality deviation; and (7) the blending ratio between geological natural gas and RNG in the area of Company's distribution system where RNG is being injected.

Company shall not be obligated to accept gas which it reasonably believes may adversely affect the standard of public utility service offered by Company, or gas which it reasonably believes may adversely affect the operation of its equipment or the gas-burning equipment of its customers. If any gas delivered hereunder fails to meet the quality specifications set forth herein, Company may, at any time, elect to refuse to accept all or any portions of such gas until Customer/Supplier brings the gas into conformity with such specifications.

DATE OF ISSUE: May 28, 2021

DATE EFFECTIVE: June 28, 2021

ISSUED BY: /s/ Kimra H. Cole

TITLE: President & Chief Operating Officer

GENERAL TERMS, CONDITIONS, RULES AND REGULATIONS
(Continued)

18. QUALITY - (Continued)

Freedom From Objectional Matter. (Continued)

Gas Quality Testing

N

Gas delivered to Company must be continuously monitored, at Customer's/Supplier's expense, to ensure it meets the quality specifications set forth above. Constituents that are not continuously monitored using currently-available technology may, at Company's discretion, be tested in a laboratory once per year at Company's expense. If the quality of the gas, based on a laboratory test, does not meet the standards set forth above, the gas must be tested in a laboratory monthly, at the Customer's/Supplier's expense, until the gas meets the required standards for three consecutive months or the Customer/Supplier otherwise demonstrates to the Company, in the Company's reasonable discretion, that it has remediated the constituent deficiency. Such tests shall include only the test method or methods that tests for the specific standard or standards that were not met, but Company may consider any results provided by such test method(s). Company will provide Customer/Supplier with at least three (3) business days' notice of the tests, and Customer/Supplier will be given the opportunity to be present and observe such tests. Company may, at its option, require Customer/Supplier to install automatic shutoff devices, at Customer's/Supplier's expense, to prevent gas that fails to meet the quality specifications set forth above from entering Company's pipeline system.

The scope of all gas testing shall follow the parameters below based on the origin of the gas. The parameters for each origin of gas are based on the source of gas and likelihood of a constituent being present in the source gas. The Company has the discretion to test for additional constituents on the list below, notwithstanding the origin of the gas, if the Company reasonably believes those constituents may be present.

Gas Quality Testing Parameters and Scope[1]

Gas Quality Parameter	Testing Method[2]	Origin of Gas			
		Geological	Landfill	Agricultural and Clean Energy	Waste Water Treatment Plant
Heat Content	In-field	X	X	X	X
Wobbe Number	In-field	X	X	X	X
Water Vapor Content	In-field	X	X	X	X
Product Gas Mercaptans	In-field	X	X	X	X
Hydrocarbon Dew Point	In-field	X	X	X	X
Hydrogen Sulfide	In-field or Lab	X	X	X	X
Total Sulfur	In-field or Lab	X	X	X	X
Total Diluent Gases including: Carbon Dioxide (CO_2) Nitrogen (N) Oxygen (O_2)	In-field	X	X	X	X
Hydrogen	Lab	X	X	X	X
Total Bacteria	Lab	X	X	X	X
Mercury	Lab		X		X
Other Volatile Metals (Lead)	Lab		X		
Siloxanes	Lab		X		X

DATE OF ISSUE: May 28, 2021

DATE EFFECTIVE: June 28, 2021

ISSUED BY: /s/ Kimra H. Cole

TITLE: President & Chief Operating Officer

GENERAL TERMS, CONDITIONS, RULES AND REGULATIONS
(Continued)

18. QUALITY - (Continued)

Freedom From Objectional Matter. Gas Quality Testing (Continued) N

Ammonia	Lab		X		X
Non-Halogenated Semi-volatile and Volatile Compounds	Lab		X		X
Halocarbons (total measured halocarbons)	Lab		X		X
Aldehyde/Ketones	Lab		X		
PCBs/Pesticides	Lab		X		

[1] Constituents to be tested for each category of gas are indicated with an "X."

[2] Testing method is defined as "In-Field" or "Lab." "In-Field" testing requires the Customer's/Supplier's use of readily available, continuously testing, industry-standard equipment, which has been reviewed and approved by Company. "Lab" testing requires the Customer/Supplier and the Company to coordinate the sampling of gas and sending it to a laboratory for testing and analysis.

19. POSSESSION OF GAS AND WARRANTY OF TITLE T

Control of Gas. Company shall be deemed to be the owner and in control and possession of the natural gas purchased on behalf of Customer until it has been physically delivered to Customer at the point or points of delivery, after which Customer shall be deemed to be the owner and in control and possession thereof.

Division of Responsibility. Customer purchasing gas from Company shall have no responsibility with respect to any natural gas until it is physically delivered to Customer, or on account of anything which may be done, happen or arise with respect to said gas before such delivery; and Company shall have no responsibility with respect to said gas after such delivery to Customer, or on account of anything which may be done, happen or arise with respect to said gas after such delivery.

Warranty of Title. Company agrees that it will, and it hereby does, warrant that it will at the time of physical delivery of gas purchased on behalf of Customer, have good title to all gas delivered by it to Customer, free and clear of all liens, encumbrances and claims whatsoever, that it will at such time of delivery have good right and title to sell said gas as aforesaid, that it will indemnify Customer and save it harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of adverse claims of any or all persons to said gas.

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(1)(b)4

Description of Filing Requirement:

New or revised tariff sheets, if applicable, identified in compliance with 807 KAR 5:011, shown either by:

(a) Providing the present and proposed tariffs in comparative form on the same sheet side by side or facing sheets side by side; or
(b) Providing a copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions.

Response:

Please see attached. In addition, the proposed tariff changes are identified and have been provided as an attachment, Schedule L, under 807 KAR 5:001 Section 16-(8)(l) located at Tab 81.

Responsible Witness:

Judy M. Cooper

COLUMBIA GAS OF KENTUCKY, INC.

INDEX

(Continued)

DATE OF ISSUE: ~~November 6, 2009~~May 28, 2021
DATE EFFECTIVE: ~~October 27, 2009~~June 28, 2021

~~Issued by authority of an Order of the Public Service Commission in Case No. 2009-00141 dated October 26, 2009~~

Issued by: ~~Herbert A. Miller, Jr.~~Kimra H. Cole
President and Chief Operating Officer
President

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[3/] $	
RATE SCHEDULE GSR					
Customer Charge per billing period	29.20~~16.00~~			29.20~~16.00~~	I
Delivery Charge per Mcf	4.2263~~3.5665~~[3/]	2.1785	2.2204~~343~~	8.6252~~7.9793~~	I
RATE SCHEDULE GSO					
Commercial or Industrial					
Customer Charge per billing period	87.15~~44.69~~			87.15~~44.69~~	I
Delivery Charge per Mcf -					
First 50 Mcf or less per billing period	3.5622~~0181~~[3/]	2.1785	2.2204~~343~~	7.9611~~4309~~	I
Next 350 Mcf per billing period	2.7494~~3295~~[3/]	2.1785	2.2204~~343~~	7.1483~~6.7423~~	I
Next 600 Mcf per billing period	2.6135~~2143~~[3/]	2.1785	2.2204~~343~~	7.0124~~6.6271~~	I
Over 1,000 Mcf per billing period	2.3782~~0143~~[3/]	2.1785	2.2204~~343~~	6.7771~~4271~~	I
RATE SCHEDULE IS					
Customer Charge per billing period	4151~~2007~~.00			4151~~2007~~.00	I
Delivery Charge per Mcf					
First 30,000 Mcf per billing period	0.7701~~6285~~[3/]		2.2204~~343~~[2/]	2.9905~~8628~~	IR
Next 70,000 Mcf per billing period	0.4579~~3737~~[3/]		2.2204~~343~~[2/]	2.6783~~080~~	IR
Over 100,000 Mcf per billing period	0.3975~~3247~~[3/]		2.2204~~343~~[2/]	2.6179~~5590~~	IR
Firm Service Demand Charge					
Demand Charge times Daily Firm Volume (Mcf) in Customer Service Agreement		11.9517		11.9517	I
RATE SCHEDULE IUS					
Customer Charge per billing period	991.20~~567.40~~			991.20~~567.40~~	I
Delivery Charge per Mcf					
For All Volumes Delivered	1.3261~~1544~~[3/]	2.1785	2.2204~~343~~	5.7250~~5672~~	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 $4.9563~~4.9702~~ per Mcf only for those months of the prior twelve months during which they were served under Rate Schedule SVGTS. R

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 May~~February~~ 28~~22~~, 2021

DATE EFFECTIVE June~~March~~ 28~~1~~, 2021 ~~(Unit 1 March)~~

ISSUED BY /s/ Kimra H. Cole

TITLE President & Chief Operating Officer

~~Issued pursuant to an Order of the Public Service Commission in Case No. 2021-00027 dated February 22, 2021.~~

COLUMBIA GAS OF KENTUCKY, INC.

3/ The Delivery Charge will be adjusted at billing by the Tax Act Adjustment Factor set forth on Sheet 7a.

DATE OF ISSUE May~~February~~ 28~~22~~, 2021

DATE EFFECTIVE June~~March~~ 28~~1~~, 2021 ~~(Unit 1 March)~~

ISSUED BY /s/ Kimra H. Cole

TITLE President & Chief Operating Officer

~~Issued pursuant to an Order of the Public Service Commission in Case No. 2021-00027 dated February 22, 2021.~~

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[3/] $	
RATE SCHEDULE SS					
Standby Service Demand Charge per Mcf Demand Charge times Daily Firm Volume (Mcf) in Customer Service Agreement		11.9517		11.9517	I
Standby Service Commodity Charge per Mcf			2.2204343	2.2204343	R
RATE SCHEDULE DS					
Customer Charge per billing period [2/]				41512007.00	I
Customer Charge per billing period (GDS only)				87.1544.69	
Customer Charge per billing period (IUDS only)				991.20567.40	
Delivery Charge per Mcf[2/]					
First 30,000 Mcf	0.77016285[3/]			0.77016285	
Next 70,000 Mcf	0.45793737[3/]			0.45793737	
Over 100,000 Mcf	0.39753247[3/]			0.39753247	
– Grandfathered Delivery Service					
First 50 Mcf or less per billing period				3.56220181[3/]	
Next 350 Mcf per billing period				2.74943295[3/]	
Next 600 Mcf per billing period				2.61352143[3/]	
All Over 1,000 Mcf per billing period				2.37820143[3/]	
– Intrastate Utility Delivery Service					
All Volumes per billing period				1.32611544[3/]	
Banking and Balancing Service Rate per Mcf		0.0469		0.0469	I
RATE SCHEDULE MLDS					
Customer Charge per billing period				282.2055.90	I
Delivery Charge per Mcf				0.0946858	I
Banking and Balancing Service Rate per Mcf		0.0469		0.0469	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.

3/ The Delivery Charge will be adjusted at billing by the Tax Act Adjustment Factor set forth on Sheet 7a.

DATE OF ISSUE	MayFebruary 282, 2021
DATE EFFECTIVE	JuneMarch 281, 2021 ~~(Unit 1 March)~~
ISSUED BY	/s/ Kimra H. Cole
TITLE	President & Chief Operating Officer

~~Issued pursuant to an Order of the Public Service Commission in Case No. 2021-00027 dated February 22, 2021.~~

COLUMBIA GAS OF KENTUCKY, INC.

CURRENTLY EFFECTIVE BILLING RATES
(Continued)

RATE SCHEDULE SVGTS	**Base Rate Charge** $	
General Service Residential (SGVTS GSR)		
Customer Charge per billing period	29.20~~16.00~~	I
Delivery Charge per Mcf	4.2263~~3.5665~~[2/]	
General Service Other - Commercial or Industrial (SVGTS GSO)		
Customer Charge per billing period	87.15~~44.69~~	
Delivery Charge per Mcf -		
First 50 Mcf or less per billing period	3.5622~~0181~~[2/]	
Next 350 Mcf per billing period	2.7494~~3295~~[2/]	
Next 600 Mcf per billing period	2.6135~~2143~~[2/]	
Over 1,000 Mcf per billing period	2.3782~~0143~~[2/]	
Intrastate Utility Service		
Customer Charge per billing period	991.20~~567.40~~	
Delivery Charge per Mcf	$ 1.3261~~1544~~[2/]	

	Billing Rate	
Actual Gas Cost Adjustment [1/]		
For all volumes per billing period per Mcf	$(0.5834)	R
RATE SCHEDULE SVAS		
Balancing Charge – per Mcf	$1.6245	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.

2/ The Delivery Charge will be adjusted at billing by the Tax Act Adjustment Factor set forth on Sheet 7a.

DATE OF ISSUE	May~~February~~ 28~~2~~, 2021
DATE EFFECTIVE	June~~March~~ 28~~1~~, 2021 ~~(Unit 1 March)~~
ISSUED BY	/s/ Kimra H. Cole
TITLE	President & Chief Operating Officer

~~Issued pursuant to an Order of the Public Service Commission in Case No. 2021-00027 dated February 22, 2021.~~

TAX ACT ADJUSTMENT FACTOR

(TAAF) T

APPLICABILITY

Applicable in the entire service territory of Company.

AVAILABILITY

~~Pursuant to the Tax Cuts and Jobs Act of 2017.~~ To implement the effects of future Federal and or Kentucky income tax reform, the ~~a~~ Tax Act Adjustment Factor is available to customers as of the effective date of an increase of decrease of the federal and/or Kentucky income tax rate based upon the applicable Rate Schedule as set forth below. The applicable Tax Act Adjustment Factor shall be applied at billing to the volumetric Delivery Charge. N N N

CALCULATION OF THE TAX ACT ADJUSTMENT FACTOR (TAAF) N

The TAAF is the difference between the income tax expense included in the revenue requirement approved by the Commission in the Company's most recent base rate proceeding and the calculated income tax expense had the increase or decrease of the Federal and or Kentucky income tax rate been in effect during the test year after applying the gross conversion factor. The allocation of the TAAF shall be based on the revenue distribution approved by the Commission.

RATE PER MCF — EFFECTIVE DATE~~S~~MONTH, YEAR T

	~~AUG 29, 2019 - NOV 26, 2019~~		~~NOV 27, 2019~~		
Rate Schedules GSR and SVGTS Residential - GSR	~~(~~($0.~~2829~~0000~~)~~	~~R~~D	~~(~~($0.~~2825~~0000)	~~I~~I	T
Rate Schedules GSO and SVGTS Commercial or Industrial GSO	($0.~~1155~~0000)	~~I~~D	($0.~~1680~~0000)	~~R~~I	T T
Rate Schedule IS	($0.~~0298~~0000)	~~R~~D	($0.~~0260~~0000)	~~I~~I	
Rate Schedule IUS and SVGTS IUS	($0.~~1703~~0000)	~~R~~D	($0.~~1160~~0000)	~~I~~I	T
Rate Schedule DS[1/]	($0.~~0298~~0000)	~~R~~D	($0.~~0260~~0000)	~~I~~I	

GAS TARIFF
PSC KY NO. 5
~~THIRD~~ FOURTH REVISED SHEET NO. 7a
CANCELLING PSC KY NO.5
~~SECOND~~ THIRD SHEET NO. 7a

COLUMBIA GAS OF KENTUCKY, INC.

Rate Schedule GDS	($0.~~1155~~0000)	~~I~~D	($0.~~1680~~0000)	~~R~~I	
Rate Schedule IUDS	($0.~~1703~~0000)	~~R~~D	($0.~~1160~~0000)	~~I~~I	
~~Rate Schedule SAS~~	~~($0.0298)~~	~~R~~	~~($0.0260)~~	~~I~~	D
~~Rate Schedule SVGTS GSR~~	~~($0.2829)~~	~~R~~	~~($0.2825)~~	~~I~~	D
~~Rate Schedule SVGTS GSO~~	~~($0.1155)~~	~~I~~	~~($0.1680)~~	~~R~~	D
~~Rate Schedule SVGTS IUS~~	~~($0.1703)~~	~~R~~	~~($0.1160)~~	~~I~~	D

1/ Excluding customers subject to the Flex Provisions of Rate Schedule DS

DATE OF ISSUE ~~August~~ May 28~~29~~, 20~~19~~21

DATE EFFECTIVE ~~August 29~~June 28,~~,~~ 20~~19~~21 ~~(Unit _1 September)~~

ISSUED BY /s/ Kimra H. Cole

TITLE President & Chief Operating Officer

~~Issued pursuant to an Order of the Public Service Commission in Case No. 202119-00267 ###### dated August Month __, 26, 202_19.~~

GENERAL SERVICE (GS) AND GENERAL PROPANE SERVICE (GPS)
SALES SERVICE RATE SCHEDULES

APPLICABILITY

Entire service territory of Company. See Sheet 8 for a list of communities.

AVAILABILITY OF SERVICE

Available to residential, commercial and industrial sales service customers.

See Sheet Nos. 53 through 56 for Temporary Volumetric Limitations and Curtailment provisions for all purposes.

BASE RATES

Residential (GSR)

Customer Charge per billing period	@ $29.20~~16.00~~
Delivery Charge per Mcf	@ $4.2263~~3.5665~~ per Mcf

Commercial or Industrial (GSO)

Customer Charge per billing period	@ $87.15~~44.69~~
Delivery Charge per Mcf -	
First 50 or less Mcf per billing period	@ $3.5622~~3.0181~~ per Mcf
Next 350 Mcf per billing period	@ $2.7494~~2.3295~~ per Mcf
Next 600 Mcf per billing period	@ $2.6135~~2.2143~~ per Mcf
Over 1,000 Mcf per billing period	@ $2.3782~~2.0143~~ per Mcf

MINIMUM CHARGE

The minimum charge per billing period shall be the applicable Customer Charge. If the meter reading or calculated consumption for the billing period is greater than zero then the minimum charge shall be increased by the Delivery Charge for a minimum of one Mcf per billing period.

GAS COST ADJUSTMENT

Gas sold under this rate schedule and rates as prescribed herein are subject to a Gas Cost Adjustment as stated on currently effective Sheet Nos. 48 through 51 of this tariff which are hereby incorporated into this rate schedule.

The charges set forth herein, exclusive of those pertaining to the minimum charge, shall be subject to a Gas Cost Adjustment, as shown on Sheet 5 of this tariff.

INTERRUPTIBLE SERVICE (IS)
SALES SERVICE RATE SCHEDULE
(Continued)

CHARACTER OF SERVICE (continued)

provision that the Customer may not concurrently contract with the Company for Delivery Service under Rate DS. The full sales agreement is subject to a minimum contract period of one (1) year as set forth in the General Terms, Conditions, Rules and Regulations, Section 34.

BASE RATES

Customer Charge
$4,151.00 ~~2,007.00~~ per billing period I

Delivery Charge per Mcf -

First 30,000 Mcf per billing period	@ $ 0.7701 ~~6285~~ per Mcf	I
Next 70,000 Mcf per billing period	@ $ 0.4579 ~~3737~~ per Mcf	I
Over 100,000 Mcf per billing period	@ $ 0.3975 ~~3247~~ per Mcf	~~N~~ I

MINIMUM CHARGE

The minimum charge each billing period for gas delivered or the right of the Customer to receive same shall be the sum of the Customer Charge of $4,151.00 ~~2,007.00~~, **plus** the Customer Demand Charge as contracted for under Firm Service. (Daily Firm Volume as specified in the Customer's service agreement multiplied by the demand rate (See Sheet No. 5). I

In the event of monthly, seasonal or annual curtailment due to gas supply shortage, the demand charge shall be waived when the volume made available is less than 110% of the Daily Firm Volume multiplied by thirty (30). In no event will the minimum charge be less than the Customer charge.

If the delivery of firm volumes of gas by Company is reduced, due to peak day interruption in the delivery of gas by Company or complete or partial suspension of operations by Customer resulting from force majeure, the Minimum Charge shall be reduced in direct proportion to the ratio which the number of days of curtailed service and complete or partial suspension of Customer's operation bears to the total number of days in the billing period. Provided, however, that in cases of Customer's force majeure, the Minimum Charge shall not be reduced to less than the Customer Charge.

GAS COST ADJUSTMENT

Except as otherwise provided herein, gas sold under this rate schedule and rates as prescribed herein are subject to the Gas Cost Adjustment, including the Commodity and Demand components, as stated on currently effective Sheet Nos. 48 through 51 herein, which are hereby incorporated into this rate schedule.

For a Customer who enters into a full sales agreement under this rate schedule after September 1, 1995, the Gas Cost Adjustment shall consist of the Expected Commodity Cost of Gas, as defined in paragraph 1 (a) of Sheet No. 48 herein, and shall not be adjusted to reflect the supplier Refund Adjustment (RA), the Actual Cost Adjustment (ACA), or the Balancing Adjustment (BA) for a period of one year from the effective date of the Customer's agreement. At the end of that one-year period, any gas purchased by the Customer under that agreement shall be subject to the Commodity Cost of Gas, including all appropriate adjustments, as defined in Sheet Nos. 48 and 49.

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TITLE	President & Chief Operating Officer

~~Issued pursuant to an Order of the Public Service Commission in Case No. 2016-00162 dated December 22, 2016~~

INTRASTATE UTILTY SALES SERVICE (IUS)
RATE SCHEDULE

APPLICABILITY

Entire service territory of Company. See Sheet No. 8 for a list of communities.

AVAILABILITY OF SERVICE

Available for service to intrastate utilities purchasing gas for resale for consumption solely within the Commonwealth of Kentucky when:

(1) Company's existing facilities have sufficient capacity and gas supply to provide the quantities of gas requested by said Customer, and

(2) Customer has executed a Sales Agreement with Company specifying, among other things, a Maximum Daily Volume.

CHARACTER OF SERVICE

Gas delivered by Company to Customer under this rate schedule shall be firm and shall not be subject to curtailment or interruption, except as provided in Section 32 of the General Terms, Conditions, Rules and Regulations.

BASE RATE

Customer Charge per billing period	\$991.20~~567.40~~	I
Delivery Charge per Mcf – For all gas delivered each billing period	\$1.3261~~1.1544~~ per Mcf.	I

MINIMUM CHARGE

The minimum charge shall be the Customer Charge.

GAS COST ADJUSTMENT

Gas sold under this rate schedule and rates as prescribed herein are subject to a Gas Cost Adjustment as stated on currently effective Sheet Nos. 48 through 51, which are hereby incorporated into this rate schedule.

The charges set forth herein, exclusive of those pertaining to the Customer Charge, shall be subject to a Gas Cost Adjustment as shown on Sheet No. 5 of this tariff.

ADJUSTMENTS AND RIDERS

Customers served under this Rate Schedule are subject to the currently effective Adjustments and Riders as prescribed on the Tariff Sheets set forth below and incorporated into this Rate Schedule:

Tax Act Adjustment Factor – Sheet No. 7a N
Rider for Natural Gas Research & Development – Sheet No. 51c
Rider SMRP~~AMRP~~ – Sheet No. 58 T

DATE OF ISSUE	May 28, 2021~~May 18, 2018~~
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SMALL VOLUME GAS TRANSPORTATION SERVICE
(SVGTS)
RATE SCHEDULE (Continued)

CHARACTER OF SERVICE

Service provided under this schedule shall be considered firm service.

DELIVERY CHARGE

The Delivery Charge shall be the Base Rate Charges for the applicable Rate Schedule as set forth below:

General Service Residential (SVGTS GSR)

Customer Charge per billing period	\$29.20~~16.00~~	I
Delivery Charge	\$4.2263~~3.5665~~ per Mcf	I

General Service Other – Commercial or Industrial (SVGTS GSO)

Customer Charge per billing period	\$87.15~~44.69~~	I
First 50 Mcf or less per billing period	\$3.5622~~3.0181~~ per Mcf	I
Next 350 Mcf per billing period	\$2.7494~~2.3295~~ per Mcf	I
Next 600 Mcf per billing period	\$2.6135~~2.2143~~ per Mcf	I
Over 1,000 Mcf per billing period	\$2.3782~~2.0143~~ per Mcf	I

Intrastate Utility Service

Customer Charge per billing period	\$991.20~~567.40~~	I
Delivery Charge per Mcf	\$1.3261~~1.1544~~	I

ADJUSTMENTS AND RIDERS

Customers served under this Rate Schedule are subject to the currently effective Adjustments and Riders as prescribed on the Tariff Sheets set forth below and incorporated into this Rate Schedule: N
Tax Act Adjustment Factor – Sheet 7a
Weather Normalization Adjustment – Sheet 51a
Energy Assistance Program Surcharge – Sheet No. 51b (Applies to Residential Customers only)
Rider for Natural Gas Research & Development – Sheet No. 51c
Energy Efficiency Conservation Rider – Sheets 51d – 51h (Applies to Residential and Commercial Customers only)
SMRP~~AMRP~~ Rider – Sheet No. 58 T

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DELIVERY SERVICE (DS)
TRANSPORTATION SERVICE RATE SCHEDULE

APPLICABILITY

Entire service territory of Company. See Sheet No. 8 for a list of communities.

AVAILABILITY

This rate schedule is available to any Customer throughout the territory served by Company provided:

(1) Customer has executed a Delivery Service Agreement with Company, and
(2) Customer has normal annual requirements of not less than 25,000 Mcf at any delivery point, and
(3) Company will not be required to deliver on any day more than the lesser of (i) a quantity of gas equivalent to Customer's Maximum Daily Volume specified in its Delivery Service Agreement; (ii) the quantity of gas scheduled and confirmed to be delivered into the Company's distribution facilities on behalf of the Customer on that day plus applicable Standby Sales; or (iii) the Customer's Authorized Daily Volume, and
(4) On an annual basis, a Customers Maximum Daily Volume and Annual Transportation Volume will be automatically adjusted to the Customers actual Maximum Daily Volume and actual Annual Transportation Volume based on the Customers highest daily and annual volumetric consumption experienced during the preceding 12-month periods ending with March billings. Upon a Customers request, the Company shall have the discretion to further adjust a Customers Maximum Daily Volume and Annual Transportation Volume for good cause shown.

Customers Grandfathered ("GDS") This rate schedule is also available to customers with normal annual requirements of less than 25,000 Mcf but not less than 6,000 Mcf, at any delivery point taking service under a contract with Company for delivery service executed prior to April 1, 1999.

Intrastate Utility ("IUDS") This rate schedule is also available to intrastate utilities for transportation and consumption solely within the Commonwealth of Kentucky.

BASE RATE

		~~D~~
Customer Charge per billing period	$4,151.00 ~~2,007.00~~	I
Customer Charge per billing period (GDS only)	$87.15 ~~44.69~~	I
Customer Charge per billing period (IUDS only)	$991.20 ~~567.40~~	I
Delivery Charge per Mcf -		
First 30,000 Mcf	$0.7701 ~~6285~~ per Mcf for all gas delivered each billing month	I
Next 70,000 Mcf	$0.4579 ~~3737~~ per Mcf for all gas delivered each billing month	IN
Over 100,000 Mcf	$0.3975 ~~3247~~ per Mcf for all gas delivered each billing month	I
Grandfathered Delivery Service		
First 50 Mcf per billing period	$3.5622 ~~0181~~	I
Next 350 Mcf per billing period	$2.7494 ~~3295~~	I
Next 600 Mcf per billing period	$2.6135 ~~2143~~	I
All Over 1,000 Mcf per billing period	$2.3782 ~~0143~~	I
Intrastate Utility Delivery Service		
All volumes per billing period	$1.3261 ~~1544~~	I
Banking and Balancing Service		
Rate per Mcf	See Sheet No. 6	

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MAIN LINE DELIVERY SERVICE (MLDS)
RATE SCHEDULE

APPLICABILITY

Entire service territory of Company. See Sheet No. 8 for a list of communities.

AVAILABILITY

This rate schedule is available to any Customer throughout the territory served by Company provided:

(1) Customer has executed a Delivery Service Agreement with Company, and
(2) Customer has normal annual requirements of not less than 25,000 Mcf at any delivery point, and
(3) Customer is connected directly through a dual-purpose meter to facilities of an interstate pipeline supplier of Company, and
(4) Company will not be required to deliver on any day more than the lesser of: (i) a quantity of gas equivalent to Customer's Maximum Daily Volume specified in its Delivery Service Agreement; (ii) the quantity of gas scheduled and confirmed to be delivered into the Company's distribution facilities on behalf of the Customer on that day plus applicable Standby Sales; or (iii) the Customer's Authorized Daily Volume, and
(5) On an annual basis, a Customers Maximum Daily Volume and Annual Transportation Volume will be automatically adjusted to the Customers actual Maximum Daily Volume and actual Annual Transportation Volume based on the Customers highest daily and annual volumetric consumption experienced during the preceding 12-month periods ending with March billings. Upon a Customers request, the Company shall have the discretion to further adjust a Customers Maximum Daily Volume and Annual Transportation Volume for good cause shown.

RATE

The transportation rate shall be $0.0946 ~~0.0858~~ per Mcf for all gas delivered each month. I D

CUSTOMER CHARGE

The customer charge shall be $282.20 ~~255.90~~ per account each billing period. I

BANKING AND BALANCING SERVICE

The rate for the Banking and Balancing Service is set forth on Sheet No. 6. This rate represents the current storage cost to the Company to provide a 'bank tolerance' to the Customer of five percent (5%) of the Customer's Annual Transportation Volume. The calculation of the Banking and Balancing Service rate is set forth in the Company's Gas Cost Adjustment.

The Banking and Balancing Service rate is subject to flexing as provided in the Flex Provision of this rate schedule. Refer to Sheet No. 91, Banking and Balancing Service, for the terms and conditions of the Balancing and Banking Service.

ADJUSTMENTS AND RIDERS

Customers served under this Rate Schedule are subject to the currently effective Adjustments and Riders as prescribed on the Tariff Sheets set forth below and incorporated into this Rate Schedule:

Rider for Natural Gas Research & Development –Sheet No. 51c

NOMINATION AND SCHEDULING OF TRANSPORTATION DELIVERIES

All transportation deliveries must be nominated and scheduled through the Company's internet based nomination system. Any customer that transports gas under this schedule may elect to have its marketer or agent make the required nominations, or the Customer may elect to connect to make daily nominations of Delivery Service gas.

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SMRP RIDER
SAFETY MODIFICATION AND REPLACEMENT PROGRAM RIDER

APPLICABILITY

Applicable to all customers receiving service under the Company's Rate Schedules GS, IS, IUS, SVGTS, DS and SAS.

CALCULATION OF SAFETY MODIFICATION AND REPLACEMENT RIDER REVENUE REQUIREMENT

The SMRP Rider Revenue Requirement includes the following:

a. SMRP-related Plant In-Service not included in base gas rates minus the associated SMRP-related accumulated depreciation and accumulated deferred income taxes;
b. Retirement and removal of plant related to SMRP construction;
c. The rate of return on the net rate base is the overall rate of return on capital authorized in the Company's latest base gas rate case, grossed up for federal and state income taxes;
d. Depreciation expense on the SMRP = related Plant In-Service less retirement and removals;
e. Property taxes related to the SMRP; and
f. Reduction for savings in Account No. 887 – Maintenance of Mains,

SAFETY MODIFICATION AND REPLACEMENT PROGRAM FACTORS

All customers receiving service under Rate Schedules GSR, GSO, IS, IUS, SVGTS, DS, GDS and SAS shall be assessed a monthly charge in addition to the Customer Charge component of their applicable rate schedule that will enable the Company to complete the safety modification and replacement program.

Rider SMRP will be updated annually in order to reflect the expected impact on the Company's revenue requirements of forecasted net plant additions and subsequently adjusted to true up the actual costs with the projected costs. A filing to update the projected costs for the upcoming calendar year will be submitted annually by October 15 to become effective with meter readings on and after the first billing cycle of January. The allocation of the program costs shall be based on the revenue distribution approved by the Commission. Company will submit a balancing adjustment annually by March 31 to true-up the actual costs, as offset by operations and maintenance expense reductions, during the most recent twelve months ended December with the projected program costs for the same period. The balancing adjustment true-up to the rider will become effective with meter readings on and after the first billing cycle of June.

The charges for the respective gas service schedules effective June 28~~April 30~~, 2021 are: T

Rate GSR, Rate SVGTS - Residential Service	$0.00~~6.63~~	~~I~~ R
Rate GSO, Rate GDS, Rate SVGTS - Commercial or Industrial Service	$0.00~~24.31~~	~~I~~ R
Rate IUS, Rate IUDS	$0.00~~207.80~~	~~I~~ R
Rate IS, Rate DS[1/], Rate SAS	$0.00~~1,221.21~~	~~I~~ R

1/ - Excluding customers subject to Flex Provisions of Rate Schedule DS

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TITLE: President & Chief Operating Officer

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COLUMBIA GAS OF KENTUCKY, INC.

GENERAL TERMS, CONDITIONS, RULES AND REGULATIONS
(Continued)

18. **QUALITY**

Processing. The gas delivered shall be natural gas; provided, however, that:

(a) Company may extract or permit the extraction of moisture, helium, natural gasoline, butane, propane or other hydrocarbons (except methane) from said natural gas, or may return thereto any substance extracted from it. Company, in order to conserve and utilize other available gases, may blend such gases with said natural gas; provided, however, that such blending shall not extend to a degree which, in Customer's judgment reasonably exercised, would materially affect the utilization of the gas delivered.

(b) Company may subject or permit the subjection of said natural gas to compression, cooling, cleaning or other processes to such an extent as may be required in its transmission from the source thereof to the point or points of delivery.

Heat Content. The ~~natural gas delivered shall contain an average total~~ Total ~~heating~~ Heating value Value ~~for any twelve (12) months period of not less than one thousand (1,000) Btu per cubic foot. Such heating value~~ of the gas shall be determined by taking samples of the gas at the point(s) of receipt at such reasonable times as may be designated by Company. The Btu content per cubic foot shall be determined by~~-~~ an accepted type of calorimeter or other suitable instrument for a cubic foot of gas at a temperature of sixty (60) degrees Fahrenheit when saturated with water vapor and at a pressure of 14.73psia~~tests at the beginning of deliveries~~, or from recording calorimeters located at such place or places as may be selected by Company. Such calorimeters shall be periodically checked, using a reference sample of gas of known heating value, or such other method as may be mutually agreed upon. Customer shall not be required to accept natural gas having a total heating value of less than nine hundred fifty (950) Btu per cubic foot, but acceptance by Customer shall not relieve Company of its obligation to supply natural gas having the said average total heating value of one thousand (1,000) Btu per cubic foot. N, D

D

The unit of volume for the purpose of determining total heating value shall be one (1) cubic foot of gas saturated with water vapor at a temperature of sixty degree (60°) Fahrenheit and an absolute pressure equivalent to thirty (30) inches of mercury at thirty-two degrees (32°) Fahrenheit and under standard gravity (32.174 ft. per second per second).

Freedom From Objectional Matter.
The gas delivered~~:~~

~~(a)~~ shall be commercially free from oil,water,air,salt, dust, gum, gum-forming constituents, harmful or noxious vapors, or other solid or liquid matter which might interfere with its merchantability or cause injury to or interference with proper operation of the lines, regulators, meters, and other equipment of N N

Company or its Customers; N

(b) ~~shall not contain more than a trace of hydrogen sulfide per one hundred (100) cubic feet of gas, as determined by methods prescribed in Standards for Gas Service, Circular of the National Bureau of Standards No. 405, Page 134 (1934 Edition), and shall be considered free from hydrogen sulfide if a strip of white filter paper, moistened with a solution containing five percent (5%) by weight of lead acetate, is not distinctly darker than a second paper freshly moistened with the same solution, after the first paper has been~~ D

GENERAL TERMS, CONDITIONS, RULES AND REGULATIONS
(Continued)

18. **QUALITY - (Continued)**

Freedom From Objectional Matter. - (Continued)

~~exposed to the gas for one (1) minute in an apparatus of approved form, through which the gas is flowing at the rate of approximately five (5) cubic feet per hour, the gas not impinging directly from a jet upon the test paper;~~ D

~~(c) shall not contain more than twenty (20) grains of total sulfur per one hundred (100) cubic feet; and~~ D

~~(d) can be measured to determine the usability of the product or the interchangeability of one gas with another gas by using a utilization factor known as the Wobbe Index. The Wobbe Index factor is calculated by dividing the saturated Btu value by the square root of the specific gravity of the sample of gas. An acceptable value for the Wobbe Index factor is one thousand three hundred (1,300) plus or minus six percent (6%).~~ D

~~In the event the gas contains more than a trace of hydrogen sulfide per one hundred (100) cubic feet or more than twenty (20) grains of total sulfur per one hundred (100) cubic feet, by test prescribed by the Bureau of Standards or other recognized method, Company, upon the request of Customer, shall reduce the hydrogen sulfide content to not more than a trace per one hundred (100) cubic feet and the total sulfur content to twenty (20) grains or less per one hundred (100) cubic feet.~~

To assure that the gas delivered by Customer/Supplier to Company conforms to the quality specifications of this Section, Customer's/Supplier's gas shall be analyzed at the point(s) of receipt from time-to-time as Company deems necessary. The gas delivered shall conform to the following gas quality specifications N

Gas Quality Specifications[1]

Gas Quality Parameter Specification	Low	High
Heat Content (Btu/scf)[2]	967	1110
Wobbe Number (+/- 6% from 1300)	1222	1378
Water Vapor Content (lbs./MM scf)		< 7
Product Gas Mercaptans (ppmv, does not include gas odorants)		< 1
Hydrocarbon Dew Point, (°F) CHDP		15
Hydrogen Sulfide (grain/100 scf)		0.25
Total Sulfur (grain/100 scf)		20
Total Diluent Gases including the following individual constituent limits: Carbon Dioxide (CO_2) 2% max Nitrogen (N) 4% max Oxygen (O_2) 1% max		5%
Hydrogen		0.3%

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President & Chief Operating Officer ~~Vice President – Regulatory Services~~

N

Total Bacteria[3] (If no filter installed, then limit is $6.4x10^7$ per 100 scf total bacteria)	Comm Free (≤ 0.2 microns
Mercury	Comm Free (< 0.06 $\mu g/m^3$
Other Volatile Metals (Lead)	Comm Free (< 213 $\mu g/m^3$)
Siloxanes as Octamethylcyclotetrasiloxane[4]	Comm Free (-< 0.5 mg Si/m
Ammonia	Comm Free (< 10 ppmv)
Non-Halogenated Semi-Volatile and Volatile Compounds	Comm Free (< 500 ppmv
Halocarbons (total measured halocarbons)[5]	< 3 ppmv
Aldehyde/Ketones	Aldehydes/Ketones must be at a level that does not unreasonably interfere with odorization of Company's gas.
PCBs/Pesticides	Comm Free (< 1 ppbv)

[1] For purposes of this Tariff, "Commercially Free" is defined as "Not Detectable" relative to typical pipeline gas flowing at the interconnect location that results in non-pipeline and/or RNG gas being compositionally equivalent to Company's flowing supplies. The analytical method, associated detection threshold, and testing facility shall be determined by the Company. Periodic testing will be required where potential Constituents of Concern are reasonably expected.

[2] Higher Heating Value is dry, @ 14.73 psia 60◦F.

[3] An acceptable alternative to Total Bacteria testing would be to include installation of a 0.2 micron particulate filter, coupled with appropriate filter maintenance practices. Initial start-up testing may include filter effectiveness analysis. Customer/Supplier shall be responsible for all costs associated with acceptable alternatives, including, but not limited to, initial start-up testing.

[4] Historical testing and data presented in this document include a siloxane detection threshold of <0.5mg Si/m3. Analytical methods have recently been improved resulting in a reduced detection threshold of <0.1mg Si/m3. Due to specific limitations of certain identified applications within an affected zone of influence, Company and Customer/Supplier may agree upon a reduced threshold.

[5] Company may refuse to accept gas containing lower levels of halocarbons if Company reasonably determines that such gas is causing harm to its facilities or the gas-burning equipment of its customers, or is adversely affecting the operation of such facilities. In addition, Company and Customer/Supplier may agree upon a different specification for halocarbons, provided that Customer/Supplier has demonstrated, to the reasonable satisfaction of Company, that non-pipeline natural gas and/or RNG meeting the agreed-upon specification will not adversely affect (a) the quality of public utility service provided by Company; (b) the operation or Company's equipment; or (c) the operation of the gas-burning equipment of Company's customers.

As used in the foregoing table, "Btu" means British thermal unit; "scf" means standard cubic foot; "MM" means one million; "CHDP" means cricondentherm hydrocarbon dew point; "ppmv" means parts per million by volume; and "ppbv" means parts per billion by volume. "RNG" or "Renewable Natural Gas" means gas, consistently primarily of methane, which (1) is derived from biogas produced by landfills, animal farms, wastewater treatment plans, or other sources, and (2) is subsequently processed by removing carbon dioxide, nitrogen, and other constituents in order to convert the biogas into pipeline-compatible gaseous fuel.

The Total Heating Value of the gas shall be determined by taking samples of the gas at the point(s) of receipt at such reasonable times as may be designated by Company. The Btu content per cubic foot shall be determined by an accepted type of calorimeter or other suitable instrument for a cubic foot of gas at a temperature of sixty (60) degrees Fahrenheit when saturated with water vapor and at a pressure of 14.73 psia. The Btu determination designated by Company shall be made by Company at its expense. Any additional Btu determinations requested by Customer/Supplier shall be at the expense of the requesting Customer/Supplier.

N

Company may, on a not-unduly discriminatory basis, accept volumes of gas, including renewable natural gas, that

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President & Chief Operating Officer ~~Vice President – Regulatory Services~~

N

fail to meet the quality specifications set forth in this tariff section, if Company determines that it can do so without adversely affecting (1) system operations; (2) the operation of the Company's equipment; (3) the operation of gas-burning equipment of Company's other customers; or (4) the quality of public utility service provided by Company. In deciding whether to accept such volumes of gas, the Company shall consider, without limitation, (1) which specifications are not being met; (2) the sensitivity of customer equipment and potential impact on such equipment; (3) Customer's plan to improve gas quality; (4) the effect on system supply; (5) interchangeability; (6) the anticipated duration of the quality deviation; and (7) the blending ratio between geological natural gas and RNG in the area of Company's distribution system where RNG is being injected.

Company shall not be obligated to accept gas which it reasonably believes may adversely affect the standard of public utility service offered by Company, or gas which it reasonably believes may adversely affect the operation of its equipment or the gas-burning equipment of its customers. If any gas delivered hereunder fails to meet the quality specifications set forth herein, Company may, at any time, elect to refuse to accept all or any portions of such gas until Customer/Supplier brings the gas into conformity with such specifications.

Gas Quality Testing

Gas delivered to Company must be continuously monitored, at Customer's/Supplier's expense, to ensure it meets the quality -specifications set forth above. Constituents that are not continuously monitored using currently-available technology may, at Company's discretion, be tested in a laboratory once per year at Company's expense. If the quality of the gas, based on a laboratory test, does not meet the standards set forth above, the gas must be tested in a laboratory monthly, at the Customer's/Supplier's expense, until the gas meets the required standards for three consecutive months or the Customer/Supplier otherwise demonstrates to the Company, in the Company's reasonable discretion, that it has remediated the constituent deficiency. Such tests shall include only the test method or methods that tests for the specific standard or standards that were not met, but Company may consider any results provided by such test method(s). Company will provide Customer/Supplier with at least three (3) business days' notice of the tests, and Customer/Supplier will be given the opportunity to be present and observe such tests. Company may, at its option, require Customer/Supplier to install automatic shutoff devices, at Customer's/Supplier's expense, to prevent gas that fails to meet the quality specifications set forth above from entering Company's pipeline system.

The scope of all gas testing shall follow the parameters below based on the origin of the gas. The parameters for each origin of gas are based on the source of gas and likelihood of a constituent being present in the source gas. The Company has the discretion to test for additional constituents on the list below, notwithstanding the origin of the gas, if the Company reasonably believes those constituents may be present.

Gas Quality Testing Parameters and Scope[1]

Gas Quality Parameter	**Testing Method[2]**	**Origin of Gas**			
		Geological	**Landfill**	**Agricultural and Clean Energy**	**Waste Water Treatment Plant**
Heat Content	In-field	X	X	X	X
Wobbe Number	In-field	X	X	X	X
Water Vapor Content	In-field	X	X	X	X
Product Gas Mercaptans	In-field	X	X	X	X
Hydrocarbon Dew Point	In-field	X	X	X	X
Hydrogen Sulfide	In-field or Lab	X	X	X	X

N

N

Total Sulfur	In-field or Lab	X	X	X	X
Total Diluent Gases including: Carbon Dioxide (CO_2) Nitrogen (N) Oxygen (O_2)	In-field	X	X	X	X
Hydrogen	Lab	X	X	X	X
Total Bacteria	Lab	X	X	X	X
Mercury	Lab		X		X
Other Volatile Metals (Lead)	Lab		X		
Siloxanes	Lab		X		X
Ammonia	Lab		X		X
Non-Halogenated Semi-volatile and Volatile Compounds	Lab		X		X
Halocarbons (total measured halocarbons)	Lab		X		X
Aldehyde/Ketones	Lab		X		
PCBs/Pesticides	Lab		X		

N

[1] Constituents to be tested for each category of gas are indicated with an "X."

[2] Testing method is defined as "In-Field" or "Lab." "In-Field" testing requires the Customer's/Supplier's use of readily available, continuously testing, industry-standard equipment, which has been reviewed and approved by Company. "Lab" testing requires the Customer/Supplier and the Company to coordinate the sampling of gas and sending it to a laboratory for testing and analysis.

T

19. POSSESSION OF GAS AND WARRANTY OF TITLE

Control of Gas. Company shall be deemed to be the owner and in control and possession of the natural gas purchased on behalf of Customer until it has been physically delivered to Customer at the point or points of delivery, after which Customer shall be deemed to be the owner and in control and possession thereof.

Division of Responsibility. Customer purchasing gas from Company shall have no responsibility with respect to any natural gas until it is physically delivered to Customer, or on account of anything which may be done, happen or arise with respect to said gas before such delivery; and Company shall have no responsibility with respect to said gas after such delivery to Customer, or on account of anything which may be done, happen or arise with respect to said gas after such delivery.

Warranty of Title. Company agrees that it will, and it hereby does, warrant that it will at the time of physical delivery of gas purchased on behalf of Customer, have good title to all gas delivered by it to Customer, free and clear of all liens, encumbrances and claims whatsoever, that it will at such time of delivery have good right and title to sell said gas as aforesaid, that it will indemnify Customer and save it harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of adverse claims of any or all persons to said gas.

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(1)(b)5

Description of Filing Requirement:

A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice.

Response:

Columbia Gas of Kentucky, Inc. has provided customer notice, as required. A copy of the customer notice is attached to Filing Requirement 17(4) at Tab 87.

Responsible Witness:

Kimra H. Cole

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(2)

Description of Filing Requirement:

A utility with gross annual revenues greater than $5,000,000 shall notify the commission in writing of its intent to file a rate application at least thirty (30) days, but not more than sixty (60) days, prior to filing its application.

(a) The notice of intent shall state if the rate application will be supported by a historical test period or fully forecasted test period.
(b) Upon filing the notice of intent, an application may be made to the commission for permission to use an abbreviated form of newspaper notice of proposed rate increases provided the notice includes a coupon that may be used to obtain a copy from the applicant of the full schedule of increases or rate changes.
(c) Upon filing the notice of intent with the commission, the applicant shall mail to the Attorney General's Office of Rate Intervention a copy of the notice of intent or send by electronic mail in a portable document format, to rateintervention@ag.ky.gov.

Response:

(a) The notice of intent was provided, as required. A copy of the notice of intent is attached.
(b) An abbreviated form of newspaper notice was not requested.
(c) A copy of the notice was transmitted to the Attorney General's Office of Rate Intervention at rateintervention@ag.ky.gov.

Responsible Witness:

Kimra H. Cole

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

COLUMBIA GAS OF KENTUCKY, INC.'S
NOTICE OF INTENT

Comes now Columbia Gas of Kentucky, Inc. ("Columbia"), by counsel, pursuant to 807 KAR 5:001, Section 16(2), and other applicable law and does hereby give notice of its intent to file, on May 28, 2021 or soon thereafter, an application seeking an adjustment of its rates using a forecasted test year. Columbia is sending a copy of this Notice of Intent to the Attorney General's Office of Rate Intervention via both mail and email addressed to rateintervention@ag.ky.gov.

This 28th day of April, 2021.

Respectfully submitted,

Mark David Goss
David S. Samford
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Counsel for Columbia Gas of Kentucky, Inc.

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(6)(a)

Description of Filing Requirement:

The financial data for the forecasted period shall be presented in the form of pro forma adjustments to the base period.

Response:

The financial data for the forecasted period is presented in the form of pro forma adjustments to the base period.

Responsible Witnesses:

Jeffery T. Gore, Jennifer Harding, Chun-Yi Lai, Judith L. Siegler, Susanne M. Taylor.

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(6)(b)

Description of Filing Requirement:

Forecasted adjustments shall be limited to the twelve (12) months immediately following the suspension period.

Response:

Forecasted adjustments have been limited to the twelve (12) months immediately following the suspension period.

Responsible Witnesses:

Jeffery T. Gore, Jennifer Harding, Chun-Yi Lai, Judith L. Siegler, Susanne M. Taylor

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(6)(c)

Description of Filing Requirement:

Capitalization and net investment rate base shall be based on a thirteen (13) month average for the forecasted period.

Response:

Capitalization and net investment rate base are based on a thirteen (13) month average for the forecasted period.

Responsible Witness:

Jeffery T. Gore

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(6)(d)

Description of Filing Requirement:

After an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless the revisions reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed. There shall be no revisions filed within thirty (30) days of a scheduled hearing on the rate application

Response:

The company acknowledges this requirement.

Responsible Witness:

Kimra H. Cole

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(6)(e)

Description of Filing Requirement:

The commission may require the utility to prepare an alternative forecast based on a reasonable number of changes in the variables, assumptions, and other factors used as the basis for the utility's forecast.

Response:

The company acknowledges this requirement.

Responsible Witness:

Kimra H. Cole

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(6)(f)

Description of Filing Requirement:

The utility shall provide a reconciliation of the rate base and capital used to determine its revenue requirements.

Response:

Please refer to the attached.

Responsible Witness:

Jeffery T. Gore

Columbia Gas of Kentucky, Inc.
Case No. 2021-00183
Reconciliation of Forecasted Test Period Rate Base to Capital
Forecasted Test Period Ending December 31, 2022

Line No.	Description	Rate Base 13 mo avg 12/31/2022	Adjustment from 13 mo avg	Rate Base 12/31/2022	Rate Making Adjustments	Balance Sheet 12/31/2022
		($000)	($000)	($000)	($000)	($000)
1	Gross Plant	676,893	42,194	719,087	(2,851)	716,236
2	Accumulated Depr. & Amort.	(176,792)	(4,294)	(181,086)	674	(180,412)
3	Cash Working Capital	-	-	-	-	-
4	Materials & Supplies	299	-	299	-	299
5	Storage Gas	36,340	-	36,340	2,281	38,621
6	Regulatory Liability - TCJA	(27,089)	438	(26,651)	-	(26,651)
7	Deferred Income Taxes and Credits	(63,427)	(18)	(63,445)	12,971	(50,474)
8	Rate Base	446,224	38,320	484,544	13,075	497,619
9	Assets not in Rate Base					
10	Construction Work in Progress					10,322
11	Investment in Subsidiaries					740
12	Cash & temporary investments					777
13	Accounts receivable					25,893
14	Deferred gas cost					(7,385)
15	Other current assets					4,259
16	Deferred assets					4,055
17	Regulatory assets					10,391
18	Other non-current assets					3,836
19	Liabilities not in Rate Base					
20	Current Liabilities					(39,180)
21	Non-current Liabilities					(22,412)
22	Total Capitalization (Includes Short-term Debt)					488,915

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky's President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

Kimra H. Cole

Columbia Exhibit No. 17

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC APPLICATION OF	)	Case No. 2021-00183
COLUMBIA GAS OF KENTUCKY, INC.	)	
FOR AN ADJUSTMENT OF RATES;	)	
APPROVAL OF DEPRECIATION STUDY;	)	
APPROVAL OF TARIFF REVISIONS;	)	
ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND	)	
NECESSITY; AND OTHER RELIEF	)	

PREPARED DIRECT TESTIMONY OF KIMRA H. COLE ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 28, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	
	)	

VERIFICATION OF KIMRA COLE

COMMONWEALTH OF KENTUCKY	)
	)
COUNTY OF FAYETTE	)

Kimra Cole, President of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of her Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Kimra Cole

Kimra Cole

The foregoing Verification was signed, acknowledged and sworn to before me this 20th day of May, 2021, by Kimra Cole.

Evelyn Long Dunn

Notary Commission No. 600778

Commission expiration: 05/15/2022

PREPARED DIRECT TESTIMONY OF KIMRA H. COLE

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Kimra H. Cole and my business address is 2001 Mercer Road, Lexington, Kentucky, 40511.

Q: What is your current position and what are your responsibilities?

A: I am employed by Columbia Gas of Kentucky, Inc. ("Columbia" or the "Company") as its President and Chief Operating Officer. My responsibilities include the general operation of the natural gas distribution utility in 30 Kentucky counties, and specifically, I am the corporate officer responsible for the leadership of Columbia and its various departments, including Field Operations, Construction, Safety, Pipeline Safety Compliance, Measurement & Regulation, Rates and Regulatory Policy, Field Operations, Construction, Governmental and Public Affairs, Communications Large Customer and Community Relations.

Q: What is your educational background and professional experience?

A: I graduated from the University of Kentucky, earning a Bachelor of Science Degree in Chemical Engineering in 1987. I joined Columbia as an

Industrial Marketing Engineer in 1987. While holding this position, I also earned my Master of Business Administration at the University of Kentucky. I held various management roles of increasing responsibility over a 15-year period with Columbia. I left the company in 2002 with the title of Director of Sales, Marketing, Engineering and Operational Services. In 2007, I joined the Lexington Fayette Urban County Government in the role of Commissioner of General Services where I had the responsibility for Parks and Recreation, Fleets, Facilities and other shared functions for the City of Lexington for a four-year term. My next position was with the Kentucky Public Service Commission as the Director of the Division of Engineering from 2011-2012. I then rejoined Columbia as the Operation Center Manager in 2012, and held that role until 2015 when I was promoted to Vice-President and General Manager. In 2017, I was accepted the role of Vice-President of Distribution Operations for NiSource Corporate Services Company ("NCSC") overseeing the internal operations that included the Integration Center, the Operations Planning department, Damage Prevention, Operation Strategy and Support and GPS for NiSource's gas distribution companies In 2019, I was promoted to my current position as President and Chief Operating Officer of Columbia.

Q. Have you previously testified before any regulatory commissions?

A. Yes, I have testified before the Kentucky Public Service Commission.

Q. What is the purpose of your testimony?

A. Through my testimony, I will provide the Commission with an overview of this base rate filing, discuss the objectives that Columbia seeks to accomplish in this proceeding and discuss the Company's performance since the last base rate proceeding in 2016. I will also introduce Columbia's other witnesses who provide detailed testimony and supporting documentation for all revenues, expenses and rate base elements included in this base rate filing.

Q. What Filing Requirements will you be supporting?

A. I will sponsor and support the following Filing Requirements:

Filing Requirement	**Description**
807 KAR 5:001 Section 14-(1)	Name, Address, Facts
807 KAR 5:001 Section 14-(2)	Corp – Incorporation, Good Standing
807 KAR 5:001 Section 16-(1)(b)1	Reason for Rate Adjustment
807 KAR 5:001 Section 16-(1)(b)2	Certificate of Assumed Name

807 KAR 5:001 Section 16-(1)(b)5	Statement about Customer Notice
807 KAR 5:001 Section 16-(2)	Notice of Intent
807 KAR 5:001 Section 16-(6)(d)	No Revisions to Forecast
807 KAR 5:001 Section 16-(6)(e)	Alternative Forecast
807 KAR 5:001 Section 16-(7)(a)	Testimony
807 KAR 5:001 Section 16-(7)(e)	Statement of Attestation
807 KAR 5:001 Section 17-(1)	Sample Notices Posted
807 KAR 5:001 Section 17-(2)	Method of Customer Notice
807 KAR 5:001 Section 17-(3)	Proof of Customer Notice
807 KAR 5:001 Section 17-(4)	Customer Notice Information
807 KAR 5:001 Section 17-(5)	Abbreviated Notice

Q. For each of the documents included within the Filing Requirements that you are supporting, were they prepared by you or someone working under your supervision?

A. Yes.

Q. Please summarize the business of Columbia.

A. Columbia is one of six natural gas local distribution companies in the NiSource Inc. ("NiSource") family of utility companies. Headquartered in

Lexington, Kentucky, Columbia's current operations resemble a long history of consolidations of other natural gas distribution companies. The result is a system made up of various different types of pipe installed during different time periods as discussed in the testimony of Columbia's Vice President of Operations, Witness David A. Roy. Columbia employs 201 active full-time employees and serves approximately 135,000 customers in 30 Kentucky counties. Through over 2,600 miles of mains, it provides natural gas service to residential, commercial and industrial customers in the counties and municipalities listed in the Tariff.

NiSource, headquartered in Merrillville, Indiana, is an energy holding company whose subsidiaries provide natural gas and electricity distribution services to approximately 3.57 million customers located within a corridor that runs from the Midwest to the Mid-Atlantic. NiSource is the successor to an Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc., which changed its name to NiSource Inc. on April 14, 1999. In connection with the acquisition of Columbia Energy Group on November 1, 2000, NiSource became a Delaware corporation registered under the Public Utility Holding Company Act of 1935, which has since been replaced by the Public Utility Holding Company Act of 2005.

NiSource remains subject to the jurisdiction of the Securities and Exchange Commission and is traded on the New York Stock Exchange with the symbol "NI". The NiSource gas distribution companies are: Northern Indiana Public Service Company ("NIPSCO"), Columbia Gas of Kentucky, Columbia Gas of Maryland, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, and Columbia Gas of Virginia.

II. SUMMARY OF COLUMBIA'S RATE FILING

Q. Please summarize Columbia's rate filing in this proceeding.

A. Columbia seeks Commission approval to increase its base rates to recover the revenue requirement associated with the capital Columbia has invested, and will continue to invest, in its facilities, as well as Columbia's operations and maintenance ("O&M") expenditures. Approval of the Company's request is necessary for Columbia to continue to provide safe and reliable natural gas service at the lowest reasonable price to its customers, while providing the Company with a reasonable opportunity to recover its costs and to earn a fair rate of return. Further, approval of this request will demonstrate to the investment community that the Commission continues to support the need for intensified focus on pipeline safety matters as well as the need for reasonable and predictable earnings. My testimony will outline, at a high level, the objectives of Columbia's filing. Details and documentation supporting each of the objectives will be provided by Company witnesses that I will introduce later in my testimony.

B. Proposed Rate Increase

Q. Will you please explain Columbia's main objective by filing this case?

A. Columbia is proposing an increase in its base rates for the fully forecasted test period of 2022. Columbia's last base rate increase was requested in 2016. Through this filing, Columbia seeks recovery of, and an opportunity to earn a return on, the capital investments being made in its distribution system which are necessary to provide safe and reliable natural gas distribution service to its customers. Columbia, its employees, and its contractors continued to provide essential services to our customers with minimal disruption despite the impact of the COVID-19 pandemic. In light of the substantial capital investment Columbia has made since its last rate case in 2016, and the large capital investments that will be made through the end of 2022, Columbia is filing this base rate case to provide itself with a reasonable opportunity to recover its capital investment in its distribution system, safety enhancements and information technology ("IT") infrastructure, as well as increases in its O&M expenditures.

Q. What is Columbia's proposed rate increase in the case and what are some of the primary drivers for the increase?

A. Based on Columbia's current base rates and Columbia's existing and planned capital and O&M programs, Columbia will experience a revenue deficiency of approximately $26.7 million, as detailed and supported in testimony of Columbia Witness Jeffery Gore (Columbia Exhibit No. 20). This revenue deficiency is driven primarily by substantial capital investments Columbia has made, and continues to make, in its system that are not otherwise recovered through operation of the Company's SMRP Rider. In addition, as addressed in the direct testimony of Columbia Witness David Roy, Columbia has experienced a significant increase in the O&M costs associated with line locates, and the Company has and will continue to make strategic investments to improve overall safety and risk reduction. Also, as detailed by Columbia Witness Rozsa, Columbia has invested in information technology, including means to address cybersecurity and enhance the work being done in the field. Further, Columbia is proposing to modify its headquarters to enhance in-state training opportunities for our employees.

Q. Has Columbia considered the impact of a rate increase on customers?

A. The Company realizes that rate increases will always have an impact on customers, however, we have successfully avoided having to file a rate increase for nearly five years. Moreover, the Company has taken and will continue to take – specific measures to assist those financially insecure customers, especially those customers who find themselves impacted by COVID-19. For example, Columbia voluntarily established a 9-month payment arrangement to offer to those customers struggling to pay their utility bills due to the impact of COVID-19.

Finally, Columbia seeks to educate and provide support for customers struggling with their monthly utility payments of the numerous assistance programs that may be available. These include the LIHEAP Subsidy and LIHEAP Crisis programs; WinterCare program; and Columbia's own home energy assistance program. We are reaching out to our customers to keep them aware of not only these traditional assistance options but also the CARES ACT utility assistance programs such as Kentucky's Healthy at Home. We will also provide customer education and outreach on the additional assistance programs contained in the American Recovery Act as program processes and funding flow to Kentucky.

In addition to the safety and reliability benefits provided by the Company's pipeline replacement program, the Company's investments in its infrastructure modernization program benefit the local economies across Columbia's service territory through the wages paid to Columbia employees, and to contractors that work on our system that are necessary to complete the work.

Q: In summary, what is Columbia requesting in this case to support this return?

A: Columbia is seeking a revenue increase of $26,694,986, or 18.11%, in order to produce rates that are fair, just and reasonable for both Columbia and its customers. This requested revenue increase is necessary for Columbia to continue to provide safe and reliable service at the lowest reasonable price to its customers.

B. Other Objectives

Q. Does Columbia have other objectives in this case?

A. Yes. In addition to Columbia's request that the Commission approve capital investment and O&M expenses related to important safety, compliance and training programs; and the inclusion (or "rolling in") of the SMRP charge into the monthly customer base rates, the Company has included several other objectives in this proceeding, including:

Enhancement of Safety Measures: The Company continues to focus its efforts and resources on the top risks to the Company's system, and is expanding the focus in several critical areas to maintain and enhance its operational capabilities. These efforts are supported by NiSource's continued implementation of Safety Management System (SMS) across its six-state footprint. NiSource's SMS focuses on identifying and mitigating potential risks, while continually assessing and improving processes and procedures to keep its employees, contractors, customers, and the public safe. The maturing SMS at NiSource supports Columbia's efforts to proactively identify, and address risks on its system, including Columbia's investments towards in-line inspection ("ILI") pursuant to the Commission's April 30, 2021 Order in Case No. 2020-00327.

Enhanced Local Training Capabilities. As detailed by Columbia Witness Roy, Columbia is proposing to modify its headquarters to provide operations based training for our employees in Kentucky. This will enable Columbia to provide a more comprehensive operator training and qualification program, and avoid the O&M expenses associated with out-of-state travel for the same training. The Company is seeking a Certificate of Public Convenience and Necessity as part of its Application to support these enhanced local training capabilities.

Q. Does the Company have any other ongoing initiatives?

A. Yes. Columbia is focused on identifying ways to continuously improve, including leveraging our company's scale, to drive efficiencies, improve our cost structure and capabilities, and enhance our ongoing commitment to safety. In order to continuously improve, the Company focuses on the following outcomes:

- A commitment to safety leadership through our ongoing SMS journey.
- Fostering innovation within teams to rethink outdated processes and drive efficiencies.

- Leveraging technology to make meaningful connections to customers and enhance service levels.
- Streamlining cost structures to drive efficiencies across the organization.
- Standardizing operations management supported by modern technology for improved speed and reliability.

To achieve these outcomes, the Company seeks to deepen focus on driving O&M efficiencies and transforming our operations to ensure we are well-positioned to deliver on our commitments to operational excellence and customer value. Safety is the first priority, and our commitment to improvement will build upon the successes we have had in our ongoing SMS journey.

Q. Would you like to address any additional items being presented in this case?

A. Yes. As outlined by Columbia Witness Rozsa (Columbia Exhibit 28) and Taylor (Columbia Exhibit 27), improvements achieved through prudent investment opportunities will result in more efficient service to customers and more rigorous record keeping. For example, the Company is investing in a field mobility initiative that will enhance work planning and scheduling tools and provide our field employees with the technology and resources they need to allow for a paperless environment. This enhancement will provide our field employees all the information they need at a job site to support the safe execution of work, while also improving the consistency and quality of records and operational data. In addition, Columbia Witness Taylor (Columbia Exhibit No. 27) explains that other initiatives, including the evolution of business services to standardized processes in certain areas using an experience vendor, and improving customer experience through digitization to allow for 24/7 access, and enhancing overall web capabilities, and collection and payment options.

C. Future Infrastructure Replacement

Q. What are the Company's future plans for infrastructure replacement?

A. As detailed by Columbia Witness Roy in his testimony, the Company intends to continue replacement at an accelerated pace in order to retire its remaining bare steel and cast iron facilities, as well as "First Generation" plastic pipe, when those sections are found to be leaking due to stress cracking or when we see stress cracking occur during other operations. In addition, as Columbia's SMS evolves, we continue to be vigilant for and identify additional risks that warrant "priority" replacement. Indeed, as detailed in Columbia Witness Rozsa's testimony, the Company continues to invest in cybersecurity enhancements, to protect Columbia's and our customers' information.

Q. Please elaborate as to how the Company has expanded risk identification?

A. The Company has established a SMS pursuant to the American Petroleum Institute's Recommended Practice (or "RP") 1173. RP-1173 provides guidance to pipeline operators for developing and maintaining a pipeline safety management system, and is intended to augment existing practices while not duplicating any other requirements. It is worth noting that the American Gas Association (AGA) Board of Directors approved a resolution recommending that all members implement RP 1173.

Q. How will SMS impact the Company's infrastructure replacement plan going forward?

A. Today, replacement of bare steel and cast iron mains and services are the priorities that drive infrastructure modernization. SMS is expanding the classes of priorities through identification of risk reduction, in addition to bare steel and cast iron.

Q. How is SMS different than other pipeline safety programs and initiatives? (DIMP, TIMP, Damage Prevention, Public Awareness, Infrastructure modernization, etc.)?

A. SMS is a proactive and systematic and all-encompassing approach to managing safety, including the structures, policies and procedures an organization uses to direct and control activities. The API has developed RP 1173 Pipeline Safety Management Systems to provide an SMS tailored for pipeline operators. SMS is well-established in other industries where safety is a top priority, including the nuclear and airline industries. The natural gas industry is embracing SMS, building upon the learnings and structures established in these other industries. The American Gas Association has recommended that all its members implement an SMS program.

While leadership commitment is critical to a successful SMS, the identification of risk happens at all levels of an organization. A Pipeline SMS places particular emphasis on proactive thinking of what can go wrong in a systematic manner, clarifying safety responsibilities throughout the pipeline operator's organization (including contractor support), the important role of top management and leadership at all levels, encouraging the non-punitive reporting of and response to safety concerns, and providing safety assurance by regularly evaluating operations to identify and address risks. These factors, plus a strong safety culture, work together to make safety programs and processes more effective, comprehensive, and integrated.

While other pipeline safety programs and initiatives, such as DIMP, TIMP, Damage Prevention, Public Awareness and Infrastructure Modernization, address specific areas of risk, these programs in large part rely on previously gathered data and react to that data. SMS is a much more proactive, systematic and holistic approach to risk management when compared to DIMP, TIMP, Public Awareness and Infrastructure Replacement programs. An SMS encompasses, supplements and supports all other safety programs and initiatives, while providing all employees with the support and resources to own risk management.

Q. How does SMS benefit Columbia's customers?

A. It enhances Columbia's risk prioritization and modeling, and strengthens and formalizes our continuous improvement processes. These enhancements will continue to improve the integration of all pipeline safety initiatives across the Company's organization. Through SMS we are increasing our rigor, and continuously learning and improving so we can identify risks and take actions to keep our employees, contractors, customers and communities safe. SMS uses the following building blocks: (1) culture – as all employees and contractors are empowered to report risks; (2) process safety – layers of protection for safe work with a focus on enhanced consistent standards and processes); and (3) asset management – accountability to effectively evaluate, prioritize, and mitigate identified risks.

III. CUSTOMER SERVICE

Q. In addition to the investments in safety, can you describe any process improvements that Columbia has made to better serve its customers?

A. Columbia has a continued focus on providing a simple and seamless experience for customers, and will continue its focus to work across all business lines to further strengthen and enhance relationships with its customers by proactively resolving their concerns and making it easier to conduct business with us. Examples of recent enhancements to improve customer interaction in include:

- Implemented the ability for customers to make bill payments via PayPal, PayPal Credit, Amazon Pay, and Venmo. Columbia also proposes in this case to waive fees associated with payments made using a credit card;
- Provided billing options to customers by making enhancements to Paperless Billing enrollment process to make it easier for to customers that prefer to enroll on the website, during online account registration, and on the phone with a Customer Service Representative;
- Launched a new Bill and Payment Alerts program so customers can receive bill reminders and payment confirmations via email or text message;
- Launched a new usage information page to provide customers with more information about their account's energy usage and month over month comparisons;
- Implemented various usability enhancements to allow customers to more easily navigate our website platform on mobile devices;
- Ensured pre-login content on Columbia’s website was able to be translated into new languages: Chinese, French, German, Japanese, Korean, Portuguese, Spanish;

- Provided customers frequent communications and updated website content with relevant safety messaging and protocols for COVID;
- Implemented a new online feature to allow customers to start, stop or move their existing service;
- Implemented a new Interactive Voice Recognition Unit at the Customer Care Center which will enable customers to interact more easily using natural language commands; and
- Currently developing a mobile application that can be downloaded by customers and will be available in the Apple App Store and Google Play Store.

Columbia is dedicated to investing in the communities we serve, and to helping enhance quality of life for our customers, as well as our employees. It is important to ensure that individuals and families within the communities we serve have what they need to thrive. Each year, we provide funding to organizations that assist people in meeting their basic needs, such as food, clothing, and shelter. Since 2016, Columbia has averaged over $130,000 in annual support of the communities we serve.

During the COVID-19 pandemic, Columbia targeted over $60,000 of its annual support to address basic needs through contributions to organizations including the Red Cross, senior citizens centers, food banks, community kitchens and the Salvation Army. Additionally, Columbia supported virtual programs developed by the Lexington Public Library that assisted students with reading challenges during the pandemic.

While safety is CKY's primary objective, customer satisfaction is critical to our success and is measured quarterly through J.D. Power and other research tools. From 2016-2020, Columbia's Overall J.D. Power Customer Satisfaction Index (CSI) increased year over year from 724 in 2016 to 783 in 2020. Although Columbia does not meet the required residential customer count to be automatically included in the J.D. Power industry survey, NiSource includes Columbia of Kentucky along with its other brands because we value the feedback this customer research tool provides. Based on its CSI scores, Columbia of Kentucky would have ranked #1 in the Midwest Midsize Segment each year between 2016-2020.

Finally, a priority for its customers and communities, Columbia continues its commitment to energy efficiency by providing a natural gas distribution system that is safe, reliable and environmentally responsible. NiSource has been included in the Dow Jones Sustainability Index since 2014 in recognition of the company’s sustainable business practices and strategy as demonstrated by continued investment in reduction of methane and carbon dioxide emissions across the organization footprint.

IV. REVENUE REQUIREMENT

Q. How did Columbia determine the revenue requirement for this case?

A. As described in the testimony of Company Witness Gore (Columbia Exhibit No. 20), Columbia reviewed its costs to serve its customers using a Future Test Year ("FTY") ending December 31, 2022, pro forma and adjusted for known and measurable changes. Columbia then compared the costs determined for the FTY to the revenues at present rates calculated for the FTY. This analysis produced a revenue deficiency, from which Columbia calculated the corresponding revenue requirement that Columbia will require to make up this deficiency, including a fair rate of return on the investment devoted to serving the public.

Q. Why is the proposed rate increase necessary to address the revenue deficiency?

A. Columbia's current rates do not provide the opportunity for the Company to recover its costs to serve its customers, including a fair rate of return on the capital invested to provide distribution service to the public in the FTY. The proposed rates have been developed to address this deficiency.

Q. Without the increase requested in this case, what rate of return will Columbia experience?

A. Without the increase requested, Columbia's overall rate of return will drop to 3.02% in the FTY.

Q. What overall rate of return and return on equity does Columbia propose in this case?

A. As detailed in the testimony of Company Witness Rea (Columbia Exhibit No. 24), the appropriate range for Columbia's return on common equity is between 10.3% and 10.8%, and he recommends that the Commission should authorize an ROE of 10.55%. Columbia Witness Rea's recommended ROE is well-reasoned and supported by his testimony. However, Columbia has elected to base its requested revenue requirement in this case is based on a 10.3% ROE, which is the low end of Witness Rea's recommended range.

Q. Using the requested ROE of 10.3%, what is Columbia's overall requested rate of return?

A. As explained by Columbia Witness Rea and as contained in Schedule J, Columbia's overall requested rate of return is 7.48%.

V. INTRODUCTION OF WITNESSES

Q. Please introduce Columbia's witnesses and describe their testimony.

A. Other Columbia witnesses providing direct testimony and supporting schedules are:

- David A. Roy, Vice President of Operations and Construction for Columbia, will address Columbia's operating system, including its DIMP plan and other safety and operational issues;
- Judy M. Cooper, Director of Regulatory Affairs, will address Columbia's proposals that include tariff revisions, and the threat of by-pass;
- Jeffery Gore, Regulatory Manager for NiSource Corporate Services Company, will present the cost of service and revenue requirement, and support the development of the rate base presented in this case;
- Kevin L. Johnson, Lead Regulatory Analyst for NiSource Corporate Services Company, will present Columbia's allocated cost of services studies and will address Columbia's revenue allocations across the various rate classes and Columbia's proposed rate design;
- Judith L. Siegler, Lead Regulatory Studies Analyst for NiSource Corporate Services Company, will support the development of revenues for both the base period and the forecasted test period as

well as the typical bill comparisons;

- Melissa Bartos, Vice President at Concentric, will provide support for the forecasted test period basis of customer counts and usage;
- Vincent V. Rea, Managing Director of Regulatory Finance Associates, LLC, will present evidence regarding Columbia's cost of capital and recommend the appropriate rates of return for Columbia;
- John J. Spanos, a President of Gannett-Fleming Valuation and Rate Consultants, LLC, will sponsor the depreciation study performed for Columbia in this proceeding;
- Chun-Yi Lai, Financial Planning Manager for NiSource Corporate Services Company, will support Columbia's Operations & Maintenance budgets and certain filing requirements;
- Susan Taylor, Director of Financial Planning for NiSource Corporate Services Company, will provide a background on how NCSC supports Columbia and the allocation of costs to Columbia;
- Michael Rozsa, Chief Information Officer for NiSource Corporate Services Company, will provide testimony regarding planned information technology investments;
- Jennifer Harding, Director, Income Tax Operations for NiSource Corporate Services Company, will provide testimony to support the

level of federal and state income taxes.

- Kimberly K. Cartella, Director Compensation for NiSource Corporate Services Company, will provide support for employee compensation and benefits programs, including incentive compensation;

Q: Does this complete your Prepared Direct Testimony?

A: Yes, however, I reserve the right to file rebuttal testimony.

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimony of David A. Roy attached. Please also see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky's President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

David A. Roy

Columbia Exhibit No. 18

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

PREPARED DIRECT TESTIMONY OF DAVID A. ROY ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 28, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	
	)	

VERIFICATION OF DAVID ROY

COMMONWEALTH OF KENTUCKY	)
	)
COUNTY OF FAYETTE	)

David Roy, Vice President of Operations and Construction of Columbia Gas of Kentucky, Inc., being duly sworn, states that he has supervised the preparation of his Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

David Roy

The foregoing Verification was signed, acknowledged and sworn to before me this 21st day of May, 2021, by David Roy.

Notary Commission No. 600778

Commission expiration: 05-15-2022

PREPARED DIRECT TESTIMONY OF DAVID A. ROY

Q: Please state your name and business address.

A: My name is David A. Roy and my business address is 2001 Mercer Road, Lexington, Kentucky, 40511.

Q: What is your current position and what are your responsibilities?

A: I am the Vice President of Operations and Construction for Columbia Gas of Kentucky, Inc. ("Columbia"). My responsibilities are to ensure the safe, reliable delivery of natural gas to all of Columbia's customers and to oversee all construction activities involving the installation of new natural gas facilities or the replacement of existing ones. Beyond these core responsibilities, I am also responsible for the safety and development of all field personnel, as well as, their direct leadership.

Q: What is your educational background and professional experience?

A: I obtained a Bachelor of Science degree in Electrical Engineering from Purdue University in 1999 and a Master's degree in Business Administration from DePaul University in 2003. I joined NiSource, the parent company of Columbia, in 1999 as an Associate in their rotational development program. In 2000, I became a Field Engineer designing electric and natural gas distribution projects for Northern Indiana Public Service Company, another subsidiary of NiSource. I was promoted to a Field Operations Leader role in 2003 overseeing field operations and maintenance crews. In 2006, I was promoted to Field Engineering Manager for Columbia Gas of Kentucky and Columbia Gas of Ohio. While in this role I was responsible for the capital program development and field engineering designs for the two states. That role was expanded to six states in 2009 when I was promoted to Director of Field Engineering for all six Columbia distribution companies. Later, in 2012, I was promoted to Vice President of Project Delivery for Columbia Pipeline Group where I oversaw the development, design and execution of all capital projects for the pipeline company. In 2015, Columbia Pipeline Group was spun off from NiSource and was subsequently acquired by TransCanada in 2016. In 2016, I was promoted to Vice President of U.S. Projects by TransCanada to oversee the development, design and execution of all of their U.S. projects. In 2019, I was hired by TRC Companies as Vice President of their gas distribution business consulting division. I was responsible for the profit/loss of that business unit with work activities in management consulting, engineering design, operations, safety management systems and field maintenance work. I returned to NiSource and Columbia in the fall of 2019 in my current role as discussed earlier in my testimony.

Q. Have you previously testified before any regulatory commissions?

A. Yes, I have provided testimony before the Public Utilities Commission of Ohio multiple times in support of an accelerated mains replacement program and before the Massachusetts Department of Public Utilities in 2012 supporting a similar type of program. Last fall, I also provided testimony in support of Columbia's annual Safety Modification and Replacement Program ("SMRP") filing in Case Number 2020-00327.

Q. What is the purpose of your testimony?

A: The purpose of my testimony is to provide a general overview of Columbia's operating territory and gas distribution system. I will discuss Columbia's Safety Management System ("SMS"), the Distribution Integrity Management Program ("DIMP"), as well as Columbia's recent operating performance. I'll also review some strategic initiatives taken to improve overall safety & risk reduction, and the following two proposals:

1. A pilot program to assess the value and benefit of using a Picarro unit to support Columbia's leak survey program.

2. Modification to Columbia's existing operating headquarters site to add the capability of performing operations-based training in Kentucky, which is the subject of the request for a Certificate of Public Convenience and Necessity.

Additionally, I will be reviewing Columbia's capital program, our SMRP performance and 2022 project plan. Included within the SMRP section is a request to allow first generation plastic pipe (pre-1982) to be eligible for recovery as part of the SMRP should we need to replace any due to leakage.

Finally, I sponsor and support the following Filing Requirements:

Filing Requirement	Description
807 KAR 5:001 Section 16-(7)(b)	Capital Construction Budget
807 KAR 5:001 Section 16-(7)(c)	Factors Used in Preparing Forecast
807 KAR 5:001 Section 16-(7)(d)	Annual and Monthly Budget Income Statement
807 KAR 5:001 Section 16-(7)(f)	Major Construction Projects
807 KAR 5:001 Section 16-(7)(g)	Other Construction Projects

COLUMBIA'S OPERATING TERRITORY AND GAS DISTRIBUTION SYSTEM

Q: Please provide an overview of Columbia's Operating Territory and describe Columbia's gas distribution system.

A: Columbia's predecessor company was incorporated in 1905. Columbia, as it stands today, is the product of consolidations of many companies over a period of time. The companies include Central Kentucky Natural Gas, Lexington Gas Company, Huntington Gas Company, Frankfort Kentucky Natural Gas Company, United Fuel Gas Company, Inland Gas Company, and Limestone Gas. As a result of these consolidations, Columbia's distribution system consists of many independent systems and various types of pipe. Generally speaking, Columbia distributes natural gas to customers from as far west as Frankfort to the eastern State border with Lexington being the largest community we serve. In all, Columbia has natural gas facilities in 30 of Kentucky's 120 counties serving approximately 135,000 customers. A more detailed account of Columbia's service territory is described in the Application.

As of January 1, 2021, Columbia owns, operates, and maintains 2,616 miles of distribution mains. These facilities are comprised of approximately 1,489 miles of plastic (polyethylene), 798 miles of coated & cathodically protected steel, 321 miles of bare steel and 4 miles of cast or wrought iron.

There is also approximately 4 miles classified as "other." Columbia also has 55.7 miles of coated & cathodically protected steel transmission lines. Finally, Columbia has 135,309 service lines that deliver natural gas to its customers. Of those service lines, 111,239 are plastic, 17,154 are coated and cathodically protected steel and 6,916 are unprotected steel.

Q: What role does Columbia serve in delivering gas to its end use customers?

A: Columbia's distribution infrastructure is the final step in the delivery of natural gas to customers from the natural gas producing regions of the United States. Columbia distributes natural gas by taking it from points of delivery, also known as "city gates," along interstate and intrastate pipelines then distributing it through the 2,616 miles of distribution mains that network underground between and through cities, towns and neighborhoods. The natural gas is then delivered by way of customer service lines to meet the demands of Columbia's residential, commercial and industrial end-use customers.

Columbia receives the natural gas commodity at the "city gate" where the transmission pressure of the gas is generally reduced to a lower pressure. An odorant known as mercaptan is often added to the natural gas at the city gate, or upstream by the supplier, before it is delivered into Columbia's distribution system. Once Columbia receives the gas, it then flows through Columbia's distribution system where additional pressure reduction typically occurs in a series of district regulator stations before being delivered to each customer.

Q: Why is it important to distinguish between the different types of pipe for main lines and services?

A: Over the decades since natural gas began to be distributed to end users, many types of pipe have been used to transport the gas. This evolution of pipe material characteristics has steadily improved the longevity of natural gas distribution systems, as well as, significantly reduced the occurrence of leakage.

Q: Please review the different pipe material pipes and their characteristics that are present in Columbia's system?

A: The system is comprised of many different types of pipe. From the 1850s to the early 1900s, Columbia's predecessor companies installed cast iron pipe throughout the early distribution systems. Cast iron was among the first materials available, besides wood and wrought iron, and had the advantage in that it was relatively strong and was easy to install. However, it was vulnerable to breakage from ground movement. When the pipe was buried to typical depths of between two and five feet, it was susceptible to cracking if heavy pressure was applied from above or ground movements from frosts or slips occurred. Further, each pipe section was not easily joined, so joints were prone to leaks. Finally, it was determined that it was unsuitable for long-distance transportation of gas because it was unable to withstand high pressures.

By the early 1900s, the industry had generally adopted steel piping for mains. These were deemed to be stronger than cast iron and able to withstand greater pressure. During this time, bare steel began replacing cast iron pipe as the material of choice when building a natural gas distribution system. During the pre- and post-World War II construction boom, gas utilities like Columbia, along with developers and customers, installed a significant amount of bare steel mains and services. Bare steel is steel pipe that has no exterior coating and has no cathodic protection installed on the pipe. The use of bare steel was common until the 1950s and 1960s when the industry began to realize that, despite its strength, bare steel was subject to corrosion and, in order to increase long-term safety and reliability, coating and cathodic protection should be applied to all new piping systems. Both exterior coatings and cathodic protection were designed to inhibit corrosion. Columbia installed its last bare steel pipe in the 1960s. By 1970, the federal government prohibited the installation of bare steel for natural gas distribution system infrastructure.

The fact is that all metals corrode as a result of the natural process of chemical interactions with their physical environment, most commonly caused by moist soil (which creates an electrolyte) around the pipe. In these circumstances, direct electric current flows from the metal surface into the electrolyte and, as the metal ions leave the surface of the pipe, corrosion takes place. This current flows in the electrolyte to the site where oxygen or water is being reduced. This site is referred to as the cathode or cathodic site. In order to combat corrosion, natural gas distribution companies began using coated steel. Unprotected coated steel refers to steel pipe with an exterior coating (intended to electrically isolate the steel from the surrounding electrolytes in the soil), but does not have cathodic protection.

Although we now know unprotected coated steel will still corrode without cathodic protection, early unprotected coated steel was considered and advancement over bare steel. But for the period from the 1940s through the 1960s, as the industry assessed its options, it was one of just a few alternative piping materials available to meet the public demand for service. By 1970, Columbia had laid its last non-cathodically protected coated steel segment. Further, since that time Columbia has retrofitted all of its unprotected coated steel facilities with cathodic protection systems. Coated steel pipe continues to be used, but it is cathodically protected with an electric current. Cathodically protected steel has all the advantages of steel in terms of strength and, because of its impressed electrical current, is highly corrosion resistant. However, it is more costly to purchase and install, and requires more ongoing maintenance than the next generation pipe – plastic.

Plastic pipe was developed in the late 1960's and has been the primary material type found in gas distribution systems ever since. Plastic pipe has proven to be very good for distribution-level pressures. It has strength and flexibility, and, as a result, is generally immune to the stress of ground movement. Plastic is also less costly to purchase and easier to join and install than steel pipe. In addition, plastic does not corrode and, therefore, does not require cathodic protection.

Q: What is Columbia doing to address the cast iron and bare steel pipe that is still in use?

A: Since 2009 Columbia has been accelerating the replacement of its cast iron and bare steel pipe. I will discuss Columbia's accelerated replacement program in detail later in this testimony. Columbia expects cast iron will be completely eliminated from use within its system by the end of 2022; while bare steel is on track to be eliminated from use by 2037.

Q: Are there any drawbacks to using plastic pipe?

A: There are two significant drawbacks to using plastic pipe. They are:

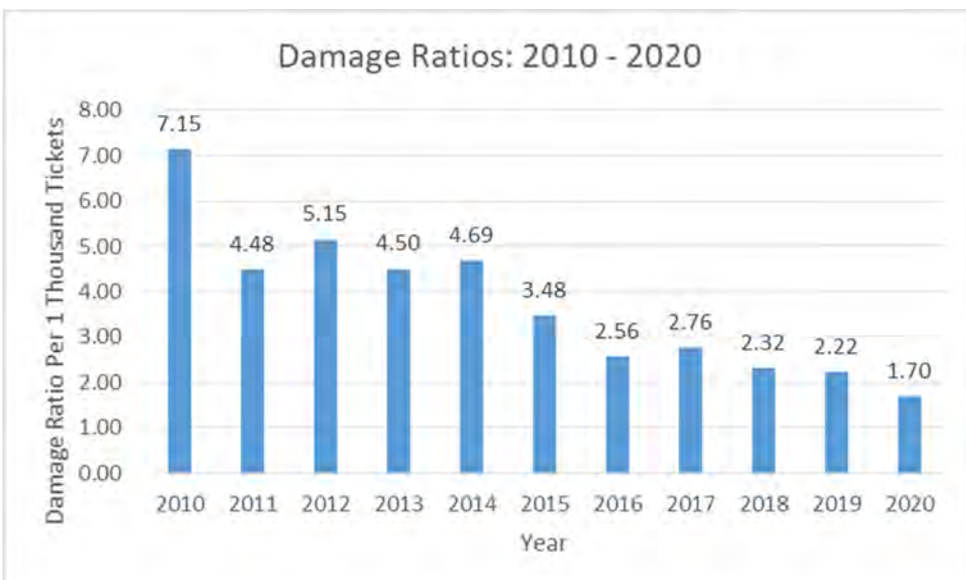
- Relative vulnerability to excavation damage as compared to cast iron or steel. As a result, excavators who do not dig by hand (despite being required to do so by the Kentucky Underground Facility Damage Prevention Act) in the vicinity of plastic facilities are very likely to damage them. Cast iron and steel piping have greater tensile strength and thus are somewhat more likely to be able to resist external impact.
- "First Generation" plastic pipe, such as Aldyl-A, typically installed between 1970 and 1981 in most distribution systems, is softer than today's material (due to the different composition of the base plastic

material). It has demonstrated itself to be prone to stress propagation cracking under some circumstances. Thus in certain limited cases, Columbia's first generation plastic pipe has generated Type-1 leaks due to significant longitudinal cracking along the pipe.

Q: What is Columbia doing to address these concerns?

A: First, Columbia has made significant progress in reducing facility damage rates. In 2010, damages per thousand locates were at 7.15; while in 2020, damages per thousand locates were at 1.70. Please see Figure 1 depicting the damage rate per thousand locates from 2010 through 2020.

Figure 1



Columbia has focused on contractor awareness and enhanced techniques for finding difficult to locate facilities, these actions have proven to be effective in reducing facility damage rates. The addition of improved State damage prevention regulations have also played a significant factor. Excavator error remains the highest cause of damages to our system, at 34% of total damages in 2020.

In order to address the issue that the industry has identified as "First Generation" plastic pipe, Columbia is replacing those sections of first generation plastic pipe when found leaking due to stress cracking or when we see stress cracking occur during other operations. Later in testimony, I will be discussing a request to allow the inclusion of first generation plastic pipe in future SMRP filings.

COLUMBIA'S SAFETY MANAGEMENT SYSTEM

Q: Describe Columbia's Safety Culture.

A: Columbia's long-term focus on continuous improvement in safety performance is rooted in its safety culture. Columbia and all NiSource companies aspire to be an industry leader in safety. It is the foremost stakeholder commitment and it guides daily work activities in the field, as well as investments in safety.

Our aspiration to be an industry leader in safety does not reflect a goal to outperform our peer companies, but rather it is about being a partner and leader in pursuit of critical shared safety goals for the natural gas industry. Columbia's safety commitment applies to all aspects of safety: customers, employees, business partners, and the communities Columbia serves. It reflects a continual focus on personal safety of people, pipeline safety for the public and the health and wellness assured through responsible environmental stewardship.

Q: Please describe Columbia's Safety Management System ("SMS").

A: Columbia's Safety Management System is a comprehensive approach to identifying risks and managing safety. It is based on American Petroleum Institute's Recommended Practice ("RP") 1173, which establishes a set of standards and best practices for the oil and natural gas industries based on the successful implementation of similar Safety Management Systems in the transportation, airline, and nuclear industries. Columbia has been assessing policies and procedures against the requirements of RP 1173 in order to ultimately align its policies and procedures with ten elements in RP 1173. These 10 essential elements are:

1. Leadership and Management Commitment

2. Stakeholder Engagement
3. Risk Management
4. Operational Controls
5. Incident Investigation, Evaluation, and Lessons Learned
6. Safety Assurance
7. Management Review and Continuous Improvement
8. Emergency Preparedness and Response
9. Competence, Awareness, and Training
10. Documentation and Recordkeeping

Additionally, Columbia has focused much time and effort on the following key efforts:

- **Asset Assessment:** Columbia is assessing risk around its assets, including customer-owned assets, building probabilistic risk assessment models, as well as analyzing, prioritizing, and building corrective action programs for identified risks. Inclusive of this area is Columbia's DIMP.
- **SMS State Risk Tables and SMS Deployment:** Columbia established SMS State Risk Tables, chaired by the state presidents and includes the top leaders in each state in which NiSource operates. The State Risk Tables assess identified risks, monitor SMS performance, assign resources to support performance improvement, and take corrective actions.

- **Corrective Action Program ("CAP"):** Columbia established a Corrective Action Program or CAP to identify risks and to take action to mitigate those risks. CAP allows all employees and contractors to submit identified issues or concerns with physical assets, materials, resourcing, tools and equipment, work methods, and issues regarding health and safety.
- **Emergency Preparedness and Response**: Columbia established and trained local leadership on Federal Emergency Management Agency ("FEMA") based emergency preparedness activities and emergency response capabilities. The team performs drills covering a broad range of potential scenarios and levels of emergency, and establishing well-defined roles with clear responsibilities.

Q: What impact has establishing an SMS had beyond the normal DIMP plan?

A: Establishing SMS as an operating model has driven a culture change to where every employee and contractor is empowered to identify and report risk. The reporting of risks through our CAP is foundational for Columbia to improve process safety and better understand our assets. We've embedded various elements of SMS into virtually all management activities, including the planning and execution of work. Ultimately, through SMS, we're increasing our rigor and continuously learning and improving so we can identify risks and take action to keep our employees, contractors, customers and communities safe.

Q: What are Columbia's biggest threats pertaining to its gas distribution system?

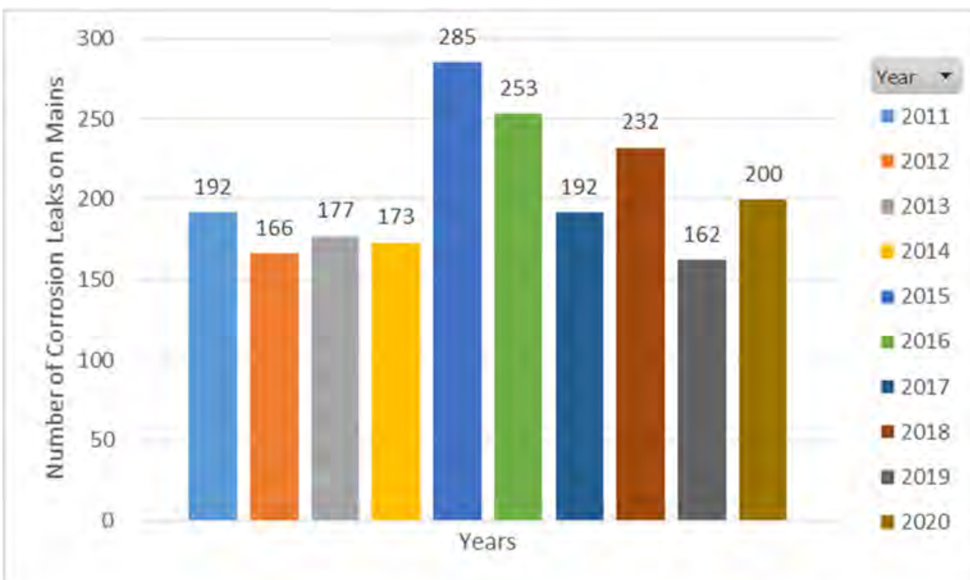
A: Columbia's 2020 DIMP identifies (10) threats that are classified as "High". Those ten threats classified as high on distribution assets are the following:

1. External Corrosion on Bare Steel Main
2. External Corrosion on Bare Steel Service
3. Various Threats to Control Lines for Control Regulators
4. 3rd Party Damage (Excavator Error) on Mains & Services
5. Vehicular Damage to Various Field Assets
6. 3rd Party Damage (Failure to Notify 811) on Mains & Services
7. Locator Error Leading to Damage on Mains & Services
8. Poor Records Leading to Damage on Mains & Services
9. Leaks on Inside the Home/Business Assets
10. Cross Bores on Mains & Services

Q: For each threat listed as "High" in Columbia's DIMP, please provide an overview of Columbia's recent performance and describe any recent strategic activities taken to mitigate those threats.

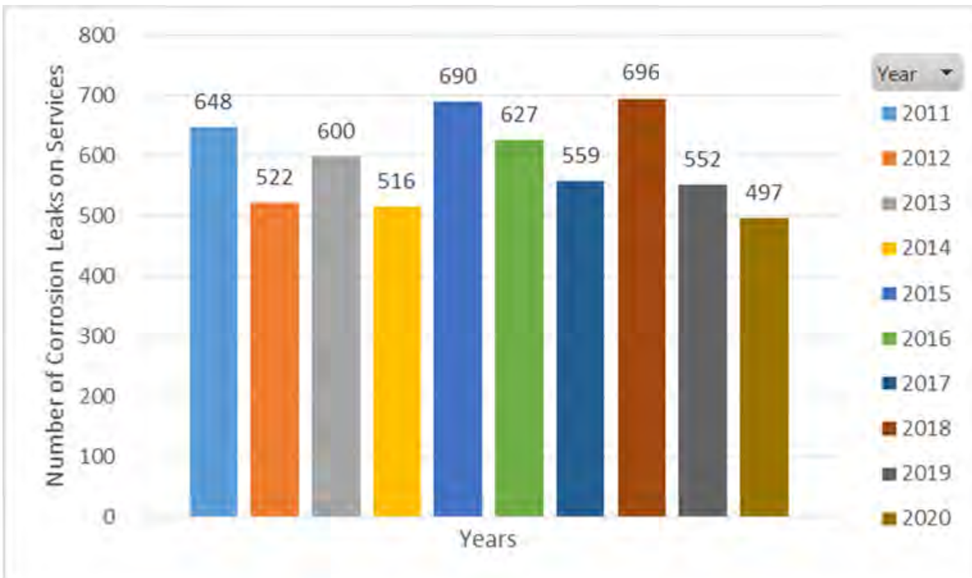
A: For Threats 1 and 2, external corrosion on bare steel main & services, Columbia has experienced a fairly consistent level of leakage over the last ten years. Figure 2 depicts the ten year history of corrosion leaks found on gas mains.

Figure 2



It shows a slightly increasing level of leakage due to corrosion on steel main lines over the last several years. This indicates that the corrosion occurring on Columbia's bare steel and unprotected steel main lines has been outpacing the replacement rate of our bare steel and unprotected steel mains included in Columbia's SMRP. To combat this, Columbia began increasing its SMRP main replacement budget over the last couple years to increase the mileage of bare steel mains that are retired from the system. Figure 3 depicts the number of corrosion leaks found on service lines over the last ten years.

Figure 3

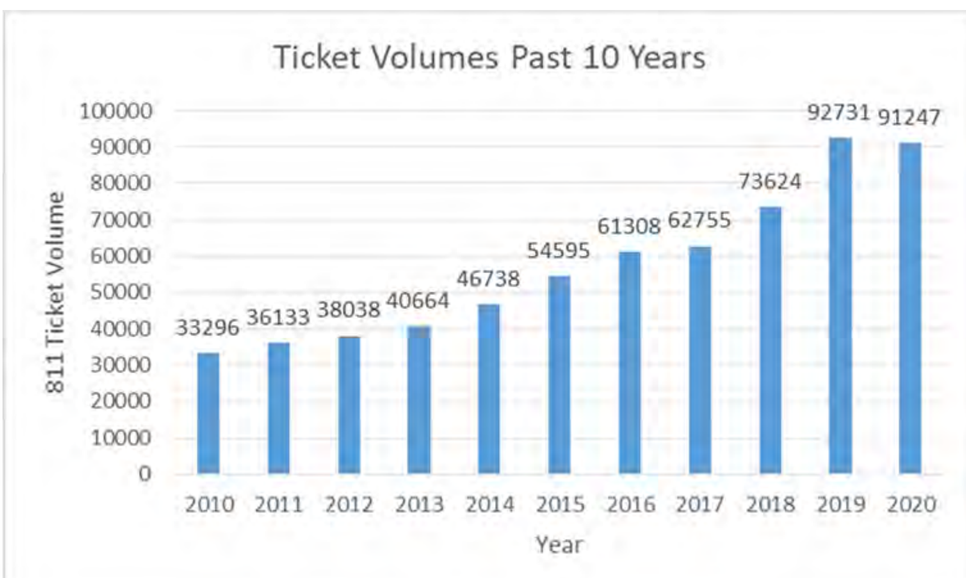


Corrosion leaks on services lines have remained relatively flat. Similar to the solution for corrosion on mains, the increased capital spend to replace aging mains and services via our SMRP should help reduce the corrosion leaks found on services in future years.

Mitigating the potential for Threat 3, threats to control lines for control regulators, has been a focus for Columbia since an incident in Columbia Gas of Massachusetts occurred where the control lines were not properly identified for a construction project. The incident led to a system over-pressurization with significant impact to the community the system served. Several steps have been taken to ensure this threat has been minimized. Some of those steps include: verifying all station drawings properly show control line details based on field conditions, requiring all construction designs to be reviewed by professional engineers, and establishing a clearance coordination center that tracks and reviews all work plans to be performed at measurement and regulation stations.

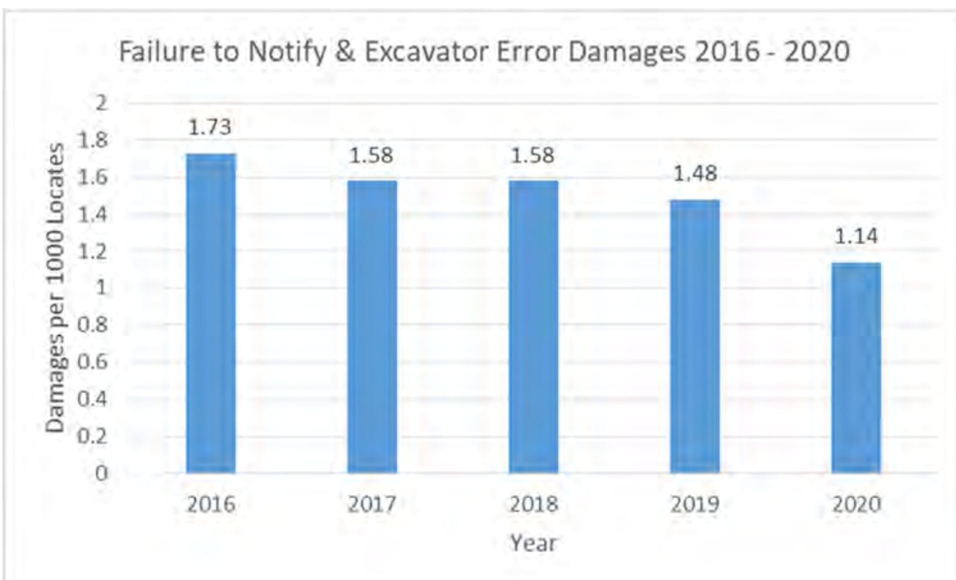
For Threats 4 & 6, 3rd party damage from excavator error and failure to call 811, please see Figure 4 depicting the last 10 years of requested locates and number of damages per 1,000 locates.

Figure 4



The number of 811 locates requested over the last ten years has increased over 250%. All costs and cost variability is absorbed by Columbia within its' operating budget. Since the last rate case alone, the 811 ticket requests have increased nearly 50%. This has a substantial impact to our budget and resource requirements to meet locate timing requirements. In fact, the largest overall factor that has increased our operations budget is since the last rate case is the increase in 811 locate requests. The cost to perform locates in 2016 was roughly $1.5 million; whereas, the cost to perform the same type of work in 2020 was over $3.5 million. Overall, Columbia has seen a drastic decrease of 3rd party damage rates to its facilities that were caused by a lack of calling 811 and excavator error as shown in Figure 5.

Figure 5

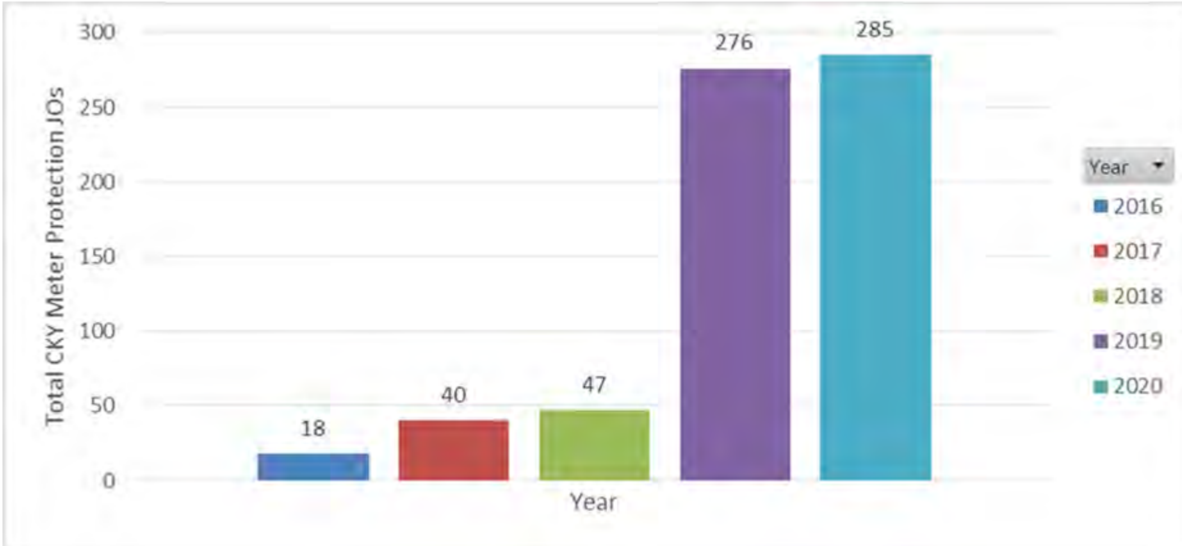


Since the last rate case we have seen the damage rate due to these two types of threats fall approximately 34% while the tickets requested has climbed nearly 50%. There are two primary contributors to these results. First, in

2018, the State of Kentucky added language to its regulations establishing penalties for excavators for not following State regulations and safe digging practices. Second, Columbia added two dedicated employees to support educating excavators on State dig law regulations and safe digging practices, as well as, Columbia began using vacuum excavation to find facilities that Columbia's facility locators could not find. The combination of these two actions by both State Legislators and Columbia have helped significantly reduce the threat of excavator damage and failure to request locates.

Threat 5, vehicle damage to field assets, is being addressed from two perspectives. First, any field asset damaged from a vehicle is assessed to determine whether bollards should be installed to provide a protective measure against the threat of vehicular damage. Second, our employees, via inspections or other routine maintenance, are requested to identify any asset that they feel is at high risk to being damaged by vehicles. The asset is then assessed to determine whether additional protection is warranted. Figure 6 shows the number of meter barrier protection orders Columbia has completed over the last five years to help reduce threat from vehicular damage.

Figure 6



Threat 7 and 8, locator error & poor records leading to damages on mains and services, are tightly linked together. Several different initiatives have been established to improve the reliability of locates from old records. From an operations perspective, Columbia initiated a change in late 2019 where vacuum excavation equipment would be utilized to visually identify our facilities when locators could not determine main and service line location thru traditional methods. From a record perspective, in 2020, Columbia also completed an initiative to ensure all service lines are mapped in the geospatial information system ("GIS") system and that the original service line drawings are accessible as an attachment in the same system. Lastly, Columbia has been piloting the collection of global positioning system ("GPS") asset data in certain installed facilities. GPS has been used to collect data for all of Columbia's critical valve locations. Additionally, Columbia has had one contractor piloting the use of GPS equipment and collecting GPS data on their projects over the last couple years. Columbia plans to implement GPS data collection for all construction projects beginning in the 2022 construction year. This data will help our locators to pinpoint asset location with ease for all newly installed pipe going forward.

Threat 9, leaks on assets inside homes/businesses, are generally either found by building owners or through inside inspections performed by company employees. In 2020, Columbia was challenged with gaining entrance to customer homes or businesses to complete inside inspections to ensure there are no active threats. Columbia has recently began sending increased notifications and will shut customers off if they do not allow entrance to complete the inspection.

Lastly, Threat 10, cross bores on mains & services, was discussed in Columbia's 2016 Rate Case (Case No. 2016-00162). After conclusion of the case Columbia elected to run a small pilot program, spanning multiple years, to determine whether or not a broad, long term investment was necessary to address this threat. From 2017 through 2020, Columbia spent approximately $1 million assessing existing mains and services for cross bores. During that pilot, Columbia assessed sanitary and storm sewers in proximity to approximately 17 miles of main and associated services and found 56 cross bores that required remediation. Based on these findings, Columbia intends to move beyond a pilot and execute a five year program assessing similar facilities in close proximity to mains and services, installed between 2010 and 2016, to find and remedy cross bores.

Q: Can you explain what a cross bore is and why it constitutes a threat to pipeline safety?

A: For most of the industry's history, pipe was installed by digging trench and laying the pipe (cast iron, steel, plastic) in the trench. As infrastructure was built in towns and cities, including roads, sidewalks, and tree belts, it became increasingly expensive to install new or replaced facilities in these built up areas of communities. As a result, a new form of pipe installation was adopted that was called "trenchless installation." Trenchless installation occurred when, instead of digging a trench and laying the pipe, a whole was punched through the ground from a launching pit to a receiving pit on the other side and a gas pipe was pulled back through without having to dig a trench. This became a preferred installation in areas of existing infrastructure because it did not necessitate expensive road repairs, nor did it disrupt traffic.

A number of years later, however, a problem with this practice became apparent. In the course of driving these pipes across the street, unbeknownst to the operator, sewer lines were penetrated, leaving a gas line sitting inside a sewer or storm drain line. These lines would often sit for a number of years until the sewer or storm drain line ultimately plugged and backed up, blocking the flow of the sewer or storm drain. A normal response by the homeowner or municipality would ordinarily be to use a mechanical auger (roto rooter) to clean out the sewer. When that happened, the mechanical auger sometimes cut the gas line, resulting in gas leaking into the sewer or storm drain, and flowing into the structures the sewer or storm drain served. These situations would tend to create an immediate and potentially hazardous public safety situation.

Additionally, as new sewers (storm and sanitary) have been constructed, operators like Columbia have found that in some instances the sewer lines have been constructed around gas mains or services. Should the mains or services be made of steel, in these instances, and corrode over time to the point of leaking, the leaked gas could travel through the sewers creating a difficult to find leak and potentially hazardous situation.

Q: What is Columbia doing to alleviate this threat?

A: Columbia has three different ways of addressing this type of threat. First, for current construction activities (new and replacement construction), Columbia's procedures require that either test holes be dug over any utility within the path of installation that could lead to a cross bore to assure damage does not occur, or pertaining to sewer and storm drain lines, that those facilities be inspected via camera (both before and after construction) to assure that a cross bore has not been created.

The second way cross bores are addressed is through a legacy review program where locations that were historically installed using trenchless technologies are visited and inspected using remote camera technology in sewers and storm drains to assure that a cross bore does not exist.

The third approach to help mitigate this threat is educating the plumbing community. Columbia has provided educational material and a $100 offer to the plumbing community for any cross bores they discover by using a camera on a sewer or drainage line prior to trying to unclog the line.

Q: Please provide an overview of the five-year cross bore program Columbia intends to begin.

A: Columbia intends to assess storm and sanitary sewers within close proximity to approximately 155 miles of plastic main and associated services installed between January 1, 2010 and December 31, 2016 over a five year period beginning in 2022, for an average annual cost of $1.3 million in operation & maintenance dollars. The total cost for the five-year cross bore program is anticipated to be approximately $6.5 million. The155 miles of plastic main represents all of the plastic main installed within Columbia's system between the years 2010 and 2016.

Q: Why did Columbia choose to assess the plastic main installed from January 1, 2010 through December 31, 2016 rather than other time frames?

A: Columbia chose the end date of December 31, 2016 because beginning January 1, 2017 Columbia began performing pre and post camera reviews of all installed main and services to try to ensure no cross bores were unintentionally created. Prior to January 1, 2017, Columbia did not comprehensively perform this camera work. The start date of January 1, 2010 was chosen because it's the beginning of the decade and would be simple to communicate and pull data from. Rather than assume all installed main should be assessed for cross bores, Columbia is attempting to choose a subset of its assets that represent the highest threat to its customers. If a cross-bore was created at the time of installation, it's less likely to have been found in more recently installed main than main that is decades old. Also, plastic main is more risky than steel main in a cross bore situation. Should roto rooter equipment be used to try to clear a drain in a cross bore situation, plastic main can easily be cut into, while steel main cannot. At the end of the five year program, Columbia would only extend the assessment for cross bores on years prior to 2010 if the data shows the threat is still significant and should be addressed.

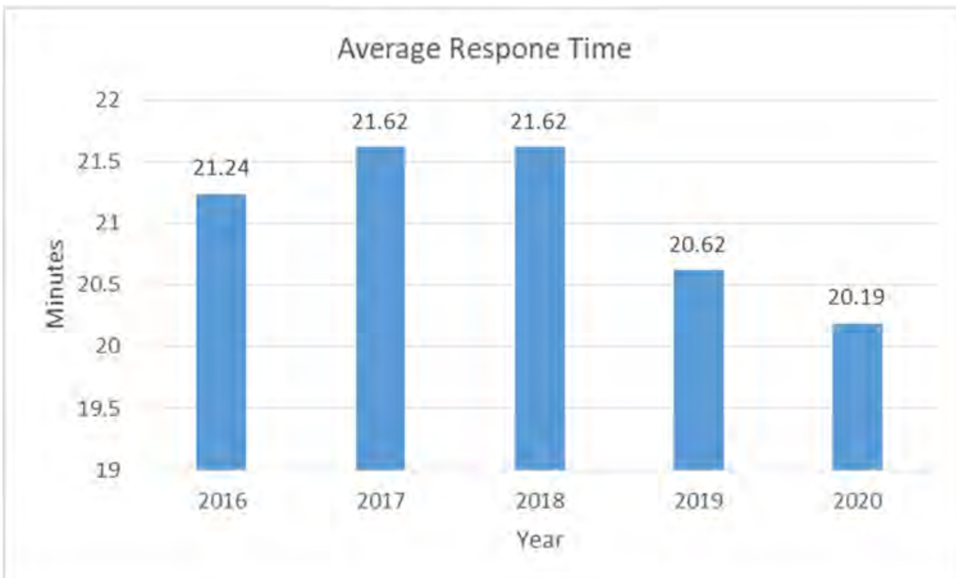
Q: Why isn't the cost of the cross bore program included in the budget used for this case?

A: Columbia had not finished assessing the pilot and developing the five year program discussed earlier when the budget was developed and approved. That work has been completed now and Columbia intends to include the cost of the program in future budgets.

Q: Please identify any other important operating performance measures.

A: Along with threat assessment and risk reduction, Columbia views emergency response a vital activity to minimize risk to customers. In the past, Columbia used a common industry goal of 60 minutes to respond to emergencies as a target for gauging its emergency response performance. However, several years ago Columbia modified that goal to be more aggressive in its response to emergencies and set its emergency response goal to 45 minutes or less. Obviously, the less time it takes an operator to respond to emergencies, the quicker the emergencies can be dealt with and prevent a situation from worsening. Some areas of our service territory are easier than others to achieve that goal. Figure 7 shows Columbia's average response time from 2016 through 2020.

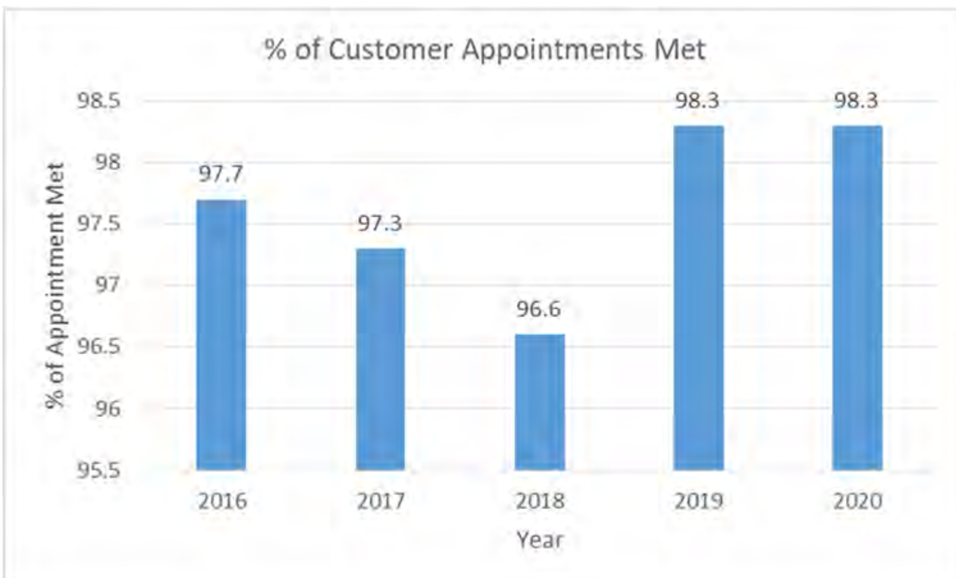
Figure 7



Columbia's goal is to continuously evaluate ways to improve the time it takes to respond to emergencies. Some improvements over the years are increasing the number of personnel able to respond to various areas and requiring certain job classifications of employees to live within a certain radius of areas they support. Additionally, Columbia invested in technology to help dispatch the closest available emergency responder based on where the emergency is at. This also eliminated the manual call-out process which could take a substantial amount of time to complete.

One other important goal that Columbia tracks and tries to improve upon is the percentage of on-time appointment kept with customers. Figure 8 shows the last five years of performance history for the percentage of on-time appointments kept.

Figure 8



Columbia prides itself on providing excellent customer service for its' customers.

Q: Are there any strategic initiatives Columbia would like to undertake?

A: Yes, Columbia would like to pilot the use of utilizing advanced leak detection equipment made by Picarro to determine whether the product should be acquired for use on a going forward basis.

Q: Please provide an overview of Picarro advanced leak detection equipment.

The Picarro system is a hardware device that is mounted on a vehicle. When driven along a route, it has the ability to detect the presence of methane up to six hundred feet away, with 1,000 times more sensitivity than traditional leak detection equipment. Its technology combines a parts-per-billion capable methane and ethane sensor, an anemometer for wind speed and direction detection, GPS technology, and a back channel to a secure cloud-based storage solution.

Q: Please explain in more detail how the Picarro System works?

A: The Picarro system is equipped to a vehicle. As a Picarro-equipped vehicle surveys an area, it collects detailed data. Unlike traditional leak detection instruments, the Picarro solution picks up trace molecules while driving through neighborhoods and measures wind velocity and other factors to narrow in on the origin of the gas up to six hundred feet away – a significant improvement over traditional survey which requires the detector to be within approximately three feet. When the survey is complete and the data analyzed, an output of the leakage can be overlaid on a gas system map to depict the locations of detected leakage. The platform is also capable of measuring relative flow rates of methane emissions to generate actionable emission measurements. Additionally, once data is captured by the Picarro system in the field, the platform provides a secure archive of all data captured which can be easily reviewed in a historical context as well as generate specific reports that are traceable, verifiable and complete and include the ability to identify potential leak locations, super emitters, and to provide a geographic overlay of relative methane emission levels.

Q: What is Columbia planning to evaluate while piloting the Picarro system?

A: Columbia intends to evaluate using the Picarro system for the following activities:

1. To determine whether the Picarro system could be used in lieu of traditional leak survey methods for some or all applications and whether there is a value proposition to do so.

2. To evaluate whether Picarro's additional advanced field leak data would improve Columbia's ability to assess our main and prioritize its replacement.
3. To evaluate whether the Picarro system is effective at identifying significant gas leaks; which, while by grading are not an immediate safety concern, but are large enough that by eliminating them could impact gas loss on system and reduce emissions.
4. To determine whether the Picarro system could be effective at ensuring there are no material leaks found in areas where new construction has been completed.

Q: Please review Columbia's proposal to pilot the Picarro system.

A: Columbia proposes to pilot the Picarro system for three months in 2022. The plan would be to utilize one Picarro equipped vehicle, owned by another NiSource company, over a three month timeframe to assess approximately 300 miles of Columbia's distribution system. Of the 300 miles of pipe to be assessed, approximately 150 miles would be pipe prone to leak like bare steel or cast iron, approximately 100 miles would be main with generally no known issues (steel or plastic), and approximately 50 miles would be gas main that was recently installed. All captured data would be analyzed and used to evaluate the activities described earlier. All leakage found would be assessed to determine what action would need to be taken. The total cost of the pilot should not exceed $300,000. Columbia would share outputs of the evaluation process with Commission Staff to help all parties determine whether the Picarro system has any viable application for Columbia and its customers. Figure 9 depicts a Columbia vehicle (from another state) equipped with Picarro equipment.

Figure 9

Q: Is there another strategic initiative that Columbia would like to undertake?

A: Yes, Columbia would like to propose making modifications to its existing operating headquarters site to add the capability of performing operations based training locally in Kentucky versus sending employees out of state to a variety of locations.

Q: Why is Columbia proposing to add training capabilities at its headquarters?

A: There are several reasons why Columbia proposes this investment.

First, these changes will enable Columbia to fully implement a new modern training program. In 2015, NiSource began making a significant investment in the development of an integrated learning strategy focused on increasing operational safety, reducing risk, and serving our customers. We recognized that the work force is both growing and changing across all natural gas utilities. As experienced generations of workers retire and others move into construction roles supporting pipeline replacement programs, companies have significant hiring needs for field employees who operate and maintain their systems. With fewer young people attending trade schools today, there is a smaller pool of skilled workers to hire from, and utilities are competing with the construction industry, oil and gas exploration companies, pipeline companies and others for this talent. Many new hires come into the job without the same level of skills and experience as previous generations of utility workers. Millennials learn and access information differently than older generations, and they demand a different way of being instructed. The nature of the work is also changing, with new equipment, materials, procedures and technologies being introduced into gas field work. Past generations of gas field workers used paper, shovels, wrenches and very basic leak detection equipment. Today's employees are using laptop computers, GPS units, document scanners and more sophisticated instruments to detect gas leaks, monitor pressures and locate underground natural gas facilities. They still turn wrenches, but there's so much more to the job than turning a wrench. In addition to changes in the industry, we needed to address the changing demographics of our field workforce. We are bringing new employees into Columbia at a rate we have never experienced. The long tenure of previous employees allowed for a long-term, in the field apprenticeship model. Going forward there are not enough qualified experienced employees to provide the same level of peer coaching. Employees performing natural gas operations and maintenance activities must achieve a level of mastery in critical work tasks. They also need to sustain that mastery, including on infrequent tasks, while continuously being introduced to new materials, technologies, processes, and procedures. Sustainment of mastery requires annual refresher training, On the Job training programs to support continuous learning. We know that training must go beyond task-based Operator Qualifications and teach employees the full scope of their job.   At the same time, we increased our Operator Qualifications program to ensure that employees can maintain and demonstrate mastery. To deliver this new training program, new training facilities were built in Ohio, Virginia and Pennsylvania for other Columbia Gas states. The new facilities feature modern, innovative teaching environments that are used to train new employees, employees transitioning into higher-skilled positions and for current employees taking annual refresher training. The training includes features allowing for hands-on training in safe, controlled environments. Columbia employees began participating and traveling to the new training facilities in 2017. The travel requirement has resulted in increased time away from core work and constrained Columbia's ability to fully participate in the new program. Participation of additional competency and refresher training has been limited due to travel constraints and resource availability. By modifying our existing building and adding some exterior improvements, Columbia will not need to send employees to other states for the majority of their training requirements. This would mitigate the operating and maintenance ("O&M") expense and loss of productivity incurred from Columbia employees traveling to Ohio, Pennsylvania or Virginia for their training needs.

Second, the addition of training capabilities within Kentucky mitigates the risk of not having qualified employees available if our State or neighboring States restrict the movement of people across state borders and our employees can't receive training to maintain their qualifications. Columbia experienced some issues with border decisions during the COVID-19 pandemic. This forced Columbia to pair up some employees to perform the same work typically performed by one employee.

Third, Columbia is moving away from a training model that historically, almost exclusively, relied upon "on the job" training in which new field personnel learned their skills from more experienced workers in actual field conditions. In 2022, Columbia intends to begin to shift its training model to a more comprehensive enhanced operator training and qualification program that would bring much more academic and skill rigor to the training and qualification process. The implementation of this enhanced training and operator qualification program must be carried out in the training facilities capable of simulating and observing task requirements. The proposed improvements made at Columbia's headquarters would support the intended training model.

For the above reasons, this additional training facility is required for public convenience and necessity.

Q: Please describe the operations and cost of the training additions.

A: The exterior improvements are proposed to be built on the west side of Columbia's property at 2001 Mercer Road in Lexington. It will consist of a few small structures containing various gas appliances & equipment typically seen in the homes of our customers. The small structures will be served by some underground facilities using both compressed air and natural gas. These improvements will allow employees to be trained in a variety of situational learning experiences, including gas line leaks, appliance line leaks, meter replacements and identifying and working safely through other tasks. The indoor facility modifications include a plant/service combined hands on lab, a pipe fusion operator qualification area and an operator qualification testing written test area. See Attachment DAR-1 for a Google Earth based picture of Columbia's Lexington headquarters with color coded areas that would be modified and improved. As there are no other natural gas utilities operating in the vicinity of the proposed facility improvements, and because it is intended for the training of Columbia personnel, the proposed construction will not compete with other public utilities.

If approved, the exterior and interior improvements are expected to be complete by end of 2022. The estimated up front capital cost is approximately $5.6 million while the on-going O&M expense would be approximately $140 thousand per year.

Q: Are other approvals needed to build this facility?

A: Columbia will comply with the notice requirements of KRS 100.324, whereby Columbia will submit its site plan for review and comment by the local planning commission in Fayette County. However, under this statute, local zoning approval is not required for the location of service facilities of public utilities under the jurisdiction of the Public Service Commission.

Additionally, Columbia intends to seek a Certificate of Public Convenience and Necessity from the Commission under KRS 278.020 even though the estimated capital cost of the facility is less than 1% of Columbia's rate base and the size, scope, purpose, expense and lack of alternatives doesn't appear to necessitate a certificate. To Columbia's knowledge, there are no similar training facilities in Columbia's service territory and therefore there is no wasteful duplication of plant, equipment, property or facilities of other jurisdictional utilities. Please refer to Attachment DAR-3 for a list of what permits from proper public authorities will be necessary to complete the proposed construction.

Q: How does Columbia propose to finance the proposed construction of this facility?

A: Columbia would fund the construction out of its' capital program. Incremental budget dollars would be added to cover the cost.

COLUMBIA'S CAPITAL PROGRAM

Q: How does Columbia categorize its capital program?

A: Columbia's capital expenditures are categorized and allocated across the following six business classes:

1. Growth (also referred to as "New Business"): expenses in this category are used for any facilities that are required to serve new customers.

2. Betterment ("Capacity" or "Compliance"): expenses in this category include facilities that are required to improve system reliability or provide additional capacity for existing customers.

3. Replacement (also referred to as "Age and Condition"): expenses in this category are for any facilities that must be replaced due to damage or physical deterioration in situations where repair is not feasible.

4. Public Improvement (also referred to as "Mandatory Relocation"): expenses in this category are for any facilities that must be relocated or raised/lowered to meet the requirements of municipal roadway reconstruction projects.

5. Support Services: This category is used to capture capital expenditures that are not directly related to the installation of distribution facilities. This includes expenditures for capitalized tools/equipment, telemetering, remote control, and other distribution communication equipment.

6. Shared Services: expenses in this category include capital investments in information technology that is allocated as NiSource corporate expenditures and managed by NiSource Corporate IT with assistance from applicable operating company personnel. Expenses in this category also include facility improvements that are specifically identified and sponsored by the NiSource management team.

Q: Please describe Columbia's capital planning and allocation process.

A: Columbia's capital planning process is integral to its overall success. In order to ensure the effectiveness of this process, a capital program management team serves as the primary administrator for the capital budget. This team facilitates consistent capital planning and allocation across NiSource, optimizes capital spending, monitors and forecasts capital expenditure, and communicates capital information to key internal departments and stakeholders.

The capital budgeting and planning process for NiSource is a continual management process. Every year meetings are held with engineering leadership to discuss the current year's progress and high level expected capital requirements for the following few years. Engineering uses feedback from local operations leadership, DIMP plans, New Business teams and local senior leadership to feed into this meeting. The output of the engineering meeting is used to develop a multi-year capital investment plan that NiSource will utilize to develop its preliminary capital budget for subsequent years.

The finalized capital needs for the following year will be reviewed and studied further prior to the annual corporate capital planning meeting. During this review period, the engineering department prioritizes the results from Optimain DS™, a decision support and risk analysis software provided by Opvantek, Inc. Columbia utilizes this software along with other factors to ensure consistency, continuity, and optimization of its capital program; with emphasis placed on accelerating the replacement of unprotected bare steel, cathodically protected bare steel, cathodically unprotected coated steel, cast iron and wrought iron. Columbia defines these types of mains as “Priority Pipe” or “Priority Mains” and capital expenditure towards this replacement activity represents a significant component of the overall capital program. SMRP related projects planned for the subsequent year will be reviewed and selected using these assessment models and other factors.

Later in the year, Columbia’s formal request for capital is presented to NiSource executive management at the annual corporate capital planning meeting. Executive management finalizes the capital budget for the next fiscal year and submits it for NiSource Board of Directors approval. The approval of the annual NiSource capital program constitutes approval of the allocation to Columbia’s capital budget and responsibility to maintain effective oversight and management of its capital expenditure at the engineering management level.

Q: Are Columbia’s capital expenditures generally consistent with its capital budgets?

A: Yes. Columbia has generally demonstrated the ability to successfully manage and execute on its capital program. Attachment DAR-2 shows the last

10 years of budget versus actual spend for Columbia's capital program. For the last 10 years Columbia has averaged just over 5% variance to its budget and for the last 5 years the average annual variance is just under 1.5%. Columbia's goal is to complete all risk based work as planned and balance the uncontrollable work (Growth & Public Improvement) with other projects that are not risk based.

Q: What is Columbia's capital program budget for the forecasted test period ending December 2022?

A: For the forecasted test period ending December 2022, Columbia intends to spend approximately $69 million in capital. See also Columbia Witness Gore for adjustments that are currently not included in the capital budget.

Q: Describe Columbia's SMRP.

A: The SMRP originally began as an Accelerated Main Replacement Program ("AMRP") approved in Case 2009-00141 from 2008. From that case, Columbia demonstrated that a significant percentage of Columbia's gas distribution mains and services are reaching the end of their useful life and the Commission provided Columbia with the means to more aggressively replace those facilities over the next 30 years ending in 2037. Post approval, Columbia began to aggressively target its riskiest priority pipe and replace those mains and services throughout its distribution system. Priority pipe was specified as unprotected bare steel, cathodically protected bare steel, cathodically unprotected coated steel, cast iron and wrought iron. As part of the original AMRP, Columbia also replaces all metallic service lines, and service lines that do not meet current material and construction standards, as well as, any associated appurtenances. Columbia originally estimated that the total program would cost approximately $210 million (in 2008 dollars) to replace the 525 miles of Priority Pipe.

Columbia's AMRP was approved to transition to an SMRP in Case No. 2019-00257. The approved SMRP combines elements from Columbia's AMRP and additional safety enhancements as identified and proposed from our Safety Management System ("SMS") program. In the November 7, 2019 Order, Columbia was granted approval to complete Phase I of an Low Pressure ("LP") Program that was to be made up of two phases. Phase 1 included installing automatic shut-off valves ("ASV's") as the primary form of overpressure protection in our low pressure systems. Also, on two small systems, we were to install low pressure gas regulators on facilities supplying those customers that perform the same function as the overpressure equipment at the district station. Additionally, we planned to install electronic instrumentation at each district LP station that can inform Columbia's Gas Control should one of these ASVs activate as well as sense other abnormal operating conditions. Phase II was under evaluation, but was intended to eliminate station by-pass valves. At this time, phase II is still under evaluation.

Q. What progress has Columbia made in its SMRP program from 2008 through 2020?

A. From 2008 through 2020 Columbia has replaced 199 miles of priority pipe, 7,412 steel service lines and associated appurtenances at a cost of approximately $220 million. Additionally, Columbia has installed ASV's and pressure monitoring equipment on 168 low pressure stations throughout the Commonwealth for a total cost of approximately $8.8 million.

Q. Please discuss Columbia's SMRP plans for the next three years?

A: SMRP spend can vary year to year based on system risks, economic markets, etc., but Columbia is planning to spend $121.6 million on the SMRP over the next three years. For 2021, Columbia anticipates that it will spend approximately $40 million in replacing Priority Pipe. In 2022 Columbia expects to spend approximately $40 million on priority pipe. For 2023, Columbia is currently planning to spend approximately $41.6 million on priority pipe. Columbia will continue to assess broad and localized system risks through its SMS program and DIMP to ensure we're addressing the right risks with available capital.

Q: How are SMRP replacement projects prioritized?

A: For priority pipe replacement, Columbia's engineering department utilizes the decision support software called Optimain DS™ to analyze relative risks associated with distribution systems. With Optimain DS™, Columbia is able to evaluate and rank pipe segments system-wide against a range of environmental conditions (e.g. population density, building class, surface cover type, etc.), risk factors (pipe segment leak history, pipe condition, pitting depth, depth of cover, etc.) and economic factors. Columbia's engineering department focuses on identifying areas with higher concentration of risk as the starting point of project selection. Areas with higher concentration of risk are evaluated to determine the appropriate plan of action that addresses the replacement strategy for the area and desired long term system design. Columbia's engineering department consults with Columbia's local operations department to obtain its input on any other operational or system reliability issues in the area.

However, Optimain DS will be replaced in 2021 with a new application. The new application is called Uptime MRP. Columbia is making the change because Optimain's provider, Opvantek, was acquired by a firm named Urbint. It's understood that Optimain will be retired and replaced with another product. Knowing this, Columbia assessed various available products and ultimately selected Uptime MRP. Uptime MRP provides a leap forward in how we'll assess and prioritize our mains and services for replacement. Columbia will be able to shift from more of a qualitative risk assessment with relative risk rankings to a quantitative risk assessment with probabilistic risk rankings. The tool will allow Columbia to consider all threats vs. using primarily external corrosion as Optimain does now.

For non-priority pipe programs or projects, Columbia evaluates risks identified through various programs or elements of SMS. Asset assessments performed by asset knowledge teams, DIMP, state risk tables and Columbia's CAP are all examples. Those risks are scored and evaluated for potential inclusion within Columbia's SMRP.

Q: Are you proposing to make any changes to the SMRP?

A: Yes, Columbia is proposing to include the replacement of first generation plastic pipe (pre-1982 and sometimes called Aldyl-A) as part of the SMRP. As discussed earlier, first generation plastic pipe has a propensity to crack under stress. Columbia installed first generation plastic, including Aldyl-A, throughout its service area from the 1960s through the early 1980s.

The use of plastic pipe has been accepted as a generally safe and economical alternative to pipe made of steel. However, in a special investigation report completed by the National Safety Board on April 23, 1998. The report concluded that between the 1960's through the early 1980's, the procedure used in the United States by manufacturers to rate the strength of this plastic pipe may have overrated the strength and resistance to brittle-like cracking. The investigation report further clarified that such first generation plastic pipe was susceptible to premature brittle-like failures when subjected to stress intensification and as a result represented a potential safety hazard.

Additionally, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued four advisory bulletins to owners and operators of natural gas pipeline distribution systems in the past concerning the susceptibility of older plastic pipe to premature brittle-like cracking. Columbia continues to perform all routine monitoring and inspecting activities to ensure that the first-generation plastic pipe within our systems continue to operate safely. However, given the safety concerns that arise when this pipe is subjected to stress intensification, the safest course of action is for Columbia to replace first-generation pipe when it is encountered within the scope of an SMRP. Columbia also proposes to include within the SMRP the replacement of first generation plastic if a leak is found on a segment of pipe or as Columbia's Optimain tool supports the replacement of isolated segments of pipe based on its Optimain risk score.

Q: Are there any large projects Columbia is undertaking that you'd like to point out?

A: Yes, in early 2021 Columbia kicked off a large in-line inspection ("ILI") project for Line DE.

Q: What is Columbia's Line DE ILI project?

A: The Line DE ILI project is a two year project beginning in 2021 that modernizes Line DE by making modifications to the transmission line so that it is capable of being assessed by ILI tools to improve the continued safe and reliable operation of the line. The project was started early in 2021 and is anticipated to be complete by end of 2022.

Line DE is a transmission line that stretches approximately 52 miles from Nicholas County to Franklin County. It supplies natural gas to Toyota Motor Manufacturing of Kentucky and a public highway CNG fueling station in addition to 6 district stations that supply such customers as Buffalo Trace, Central Manufacturing, Kentucky Smelting Technologies, Woodford Reserve Barrel Warehouses, Lakeshore Learning, Minnesota Mining & Manufacturing, Central Motor Wheel of America, backup power generation for Kentucky Utilities, the Delaplain Industrial Park, the Lane's Run Business Park, and others. Those stations also provide natural gas supplies to the commercial and residential customers in communities including Paris, Cynthiana, Georgetown, Frankfort, and Versailles. Line DE transports approximately 20% of the natural gas moved through Columbia's system.

Q: **What is In-line Inspection ("ILI")?**

A: ILI is the most thorough and reliable pipeline integrity assessment method currently available to natural gas pipeline operators to assess the internal and external condition of transmission pipelines. ILI enables a pipeline operator to learn about the pipelines' physical properties relative to the condition of protective barriers used to protect these pipeline assets. The data received from ILI assessments supports predicting the integrity of those pipelines into the future to address time dependent, time independent and resident threats as well as other threats to pipeline integrity. It involves running technologically advanced inspection tools, often called "smart pigs," through the inside of the pipeline to collect data about the pipe, and then using that data to identify anomalies that may require further investigation or repair. ILI is advantageous over other assessment methods for health and operability evaluations such as Direct Assessment ("DA") and Hydrostatic pressure testing ("PT") due to the availability precise diagnostic data for 7 of the 9 identified threat categories to transmission pipelines as identified in American Society of Mechanical Engineering ("SME") B31.8 S. The nine threat categories are: 1) External Corrosion, 2) Internal Corrosion, 3) Stress Corrosion Cracking, 4) Mechanical Damage (3rd Party etc.), 5) Manufacturing, 6) Construction, 7) Weather and Outside Force, 8) Equipment, and 9) Incorrect Operations. The first seven threats categories are covered by ILI tooling.

PT does assess for these range of threats as well but, but provides no information to predict if the health of the pipe is changing. PT essentially lets you know that the pipe can currently support the operating pressure, but nothing about whether there is a problem that could cause an incident later. There is no additional data from PT that would provide an operator with key areas of trending degradation to the system supporting some other remedial action to prevent and mitigate the deleterious effects of the threat like an operator receives with ILI. PT can also cause service interruptions or additional cost considerations for supplemental gas service to these sections as well as environmental costs to dispose of water used in the hydrostatic process. In order to pressure test a line, it has to be taken out of service.

DA only addresses three threats effectively. External Corrosion, internal corrosion and mechanical threats can be assessed with DA. However, DA is location specific. Typically DA is performed at just a few points along the length of a pipeline. All pipe in between the DA dig points is completely unassessed.

Q: **Please explain the benefit of modifying Line DE for ILI?**

A: Columbia will markedly improve the identification of anomalies from threats including external corrosion, internal corrosion and mechanical damage. Also, Columbia will have better visibility into stresses and anomalies created by outside force conditions introduced by water crossings and land subsidence or adverse loading conditions created by both overburden and shallow pipe conditions. The numerous elevation changes realized in the construction from Lake Carnico Station to Jim Beam Station may have potentially introduced stress points into the pipeline during original construction or transition into adverse conditions during the years of changes within the pipeline corridor.

An ILI assessment would provide Columbia a continuous and full view of the pipeline from the launcher to receiver. Columbia would address any key findings and use the data to proactively identify risks and take action prior to a failure or loss of service event.

Enabling Line DE to use ILI as the primary integrity assessment tool both in HCAs and non-HCAs not only aligns Columbia with industry best practices, but also provides Columbia with the opportunity to develop better data upon which it can more effectively evaluate and manage both the current and future asset health of Line DE.

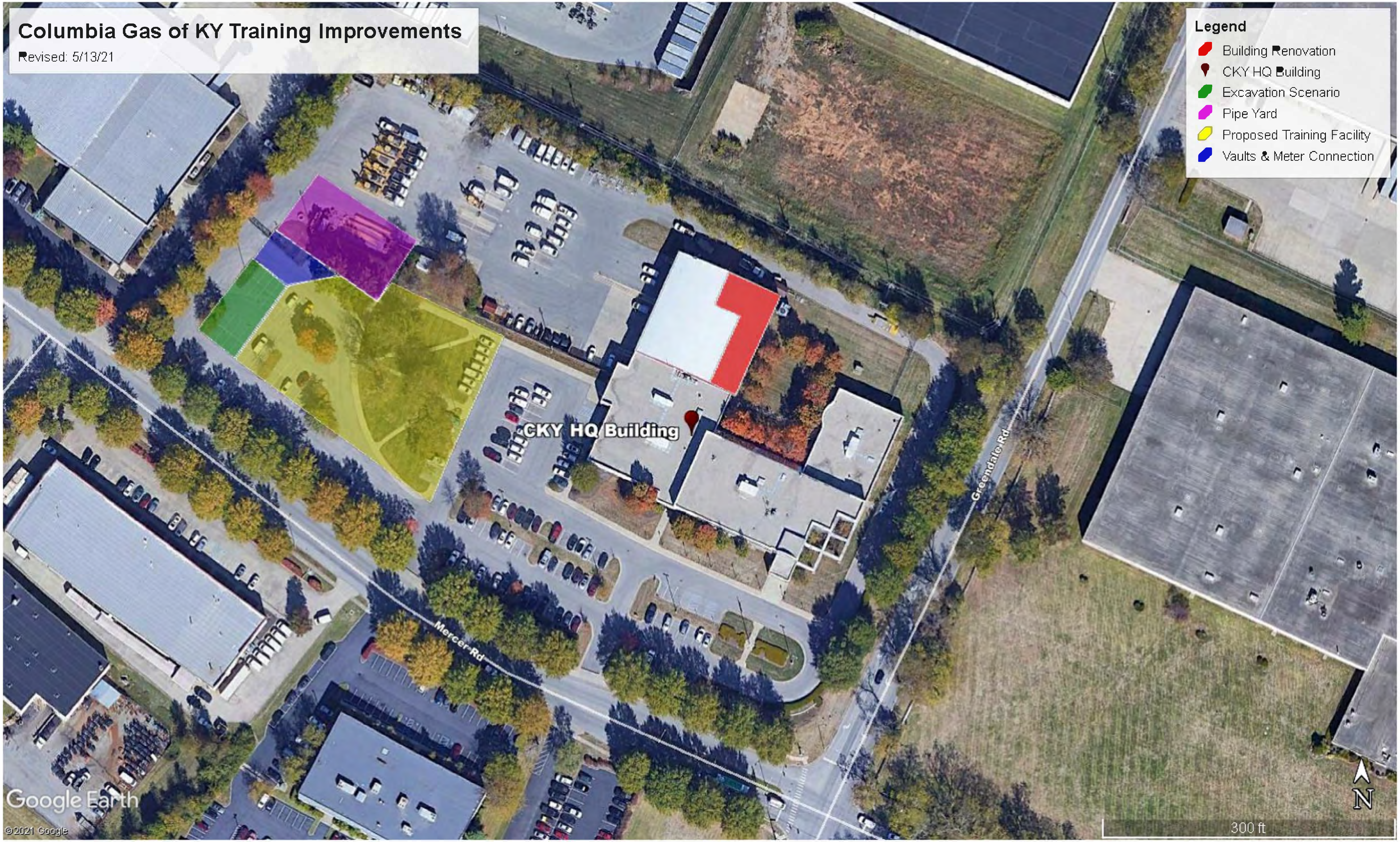
Q: Is Columbia on track to complete the replacement of its priority pipe by 2037 as originally intended?

A: Columbia is currently about 5% off the pace to complete the priority pipe replacement by 2037, however, Columbia expects to close that gap over the next three years based on the current capital program projections. Columbia is expecting to eliminate all cast iron within its gas distribution system by the end of 2022.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony if necessary.

ATTACHMENT DAR-1
MAP OF TRAINING FACILITY


Columbia Gas of KY Training Improvements
Revised: 5/13/21
Legend
Building Renovation
CKY HQ Building
Excavation Scenario
Pipe Yard
Proposed Training Facility
Vaults & Meter Connection
CKY HQ Building
Greendale Rd
Mercer Rd
Google Earth
©2021 Google
300 ft
N

ATTACHMENT DAR-2
ANNUAL BUDGET
TO ACTUAL CAPITAL

Columbia Gas of Kentucky, Inc.
Annual Budget to Actual Capital

Years	Annual Actual Cost	Annual Original Budget	Variance in Dollars	Variance in Percent
2011	$14,348	$12,159	$2,189	18.003%
2012	$18,904	$14,650	$4,254	29.038%
2013	$24,747	$21,335	$3,412	15.993%
2014	$32,190	$29,758	$2,432	8.173%
2015	$31,614	$30,105	$1,509	5.012%
2016	$27,024	$27,947	-$923	-3.303%
2017	$34,934	$34,617	$317	0.916%
2018	$43,102	$43,174	-$72	-0.167%
2019	$53,837	$52,293	$1,544	2.953%
2020	$64,965	$62,567	$2,398	3.833%
Totals	$345,665	$328,605	$17,060	5.192%

ATTACHMENT DAR-3
LIST OF PERMITS REQUIRED FOR TRAINING FACILITIES

<u>List of Permits Required for the Construction of Additional Training Capabilities to Existing Headquarters</u>[1]

Lexington-Fayette Urban County Government
Division of Building Inspection[2]
Building Permit

Lexington-Fayette Urban County Government
Division of Building Inspection
Electrical Permit

Lexington-Fayette Urban County Government
Division of Building Inspection
Structural Permit

Lexington-Fayette Urban County Government
Division of Building Inspection
Plumbing Permit

Kentucky Public Protection Cabinet
Department of Housing, Buildings and Construction
Plumbing Construction Permit

Lexington-Fayette Urban County Government
Division of Planning[3]
Planning Application

[1] As permits are issued and if any additional requirements are identified, the Company will supplement this Attachment
[2] 200 East Main St., Lexington, KY 40507
[3] 101 E. Vine St., Suite 700, Lexington, KY 40507

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimony of Judy M. Cooper attached. Please also see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky's President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

Judy M. Cooper

Columbia Exhibit No. 19

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC APPLICATION OF CO-	)	Case No. 2021-00183
LUMBIA GAS OF KENTUCKY, INC.	)	
FOR AN ADJUSTMENT OF RATES;	)	
APPROVAL OF DEPRECIATION	)	
STUDY; APPROVAL OF TARIFF REVI-	)	
SIONS; ISSUANCE	)	
OF A CERTIFICATE OF PUBLIC CON-	)	
VENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	

PREPARED DIRECT TESTIMONY OF
JUDY M. COOPER
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

Mark David Goss
David S. Samford
L. Allyson Honaker
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Email: josephclark@nisource.com

Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 28, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	
	)	

VERIFICATION OF JUDY COOPER

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF FAYETTE)

Judy Cooper, Director of Regulatory Affairs of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of her Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Judy Cooper
Judy Cooper

The foregoing Verification was signed, acknowledged and sworn to before me this 20th day of May, 2021, by Judy Cooper.

Evelyn Long Dunn

Notary Commission No. 600778

Commission expiration: 05/15/2022

PREPARED DIRECT TESTIMONY OF JUDY M. COOPER

Q: Please state your name and business address.

A: My name is Judy M. Cooper and my business address is Columbia Gas of Kentucky, Inc., 2001 Mercer Road, Lexington, Kentucky, 40511.

Q: What is your current position and what are your responsibilities?

A: I am the Director of Regulatory Affairs for Columbia Gas of Kentucky, Inc. ("Columbia"). I am responsible for the management of Columbia's regulatory affairs, tariffs and filings with the Kentucky Public Service Commission ("Commission"), including quarterly Gas Cost Adjustments.

Q: What is your educational background?

A: I obtained a Bachelor of Science Degree in Accounting from the University of Kentucky in 1982. In 1985, I received a Master's Degree in Business Administration from Xavier University.

Q: What is your employment history?

A: I began my employment with the Commission as an auditor in 1982. Subsequently, I served as Rate Analyst, Energy Policy Advisor, Branch Manager of Electric and Gas Rate Design, and Director of Rates, Tariffs and Financial Analysis at the Commission. In July of 1998, I joined Columbia as Manager of Regulatory Services and have remained in regulatory and government roles. My job title currently is Director, Regulatory Affairs.

Q: Have you previously testified before the Kentucky Public Service Commission?

A: Yes, I have testified before the Kentucky Public Service Commission in seven cases for Columbia: Case No. 2002-00117, *The Filing by Columbia Gas of Kentucky, Inc. to Require that Marketers in the Small Volume Gas Transportation Program be Required to Accept a Mandatory Assignment of Capacity;* Case No. 2007-00008, *In the Matter of Adjustment of Rates of Columbia Gas of Kentucky, Inc.;* Case No. 2009-00141, *In the Matter of an Adjustment of Rates of Columbia Gas of Kentucky, Inc.;* Case No. 2010-00146, *An Investigation of Natural Gas Retail Competition Programs;* and Case No. 2013-00167, *In the Matter of Application of Columbia Gas of Kentucky, Inc., for an Adjustment of Rates for Gas Service,* Case No. 2017-00453, *In the Matter of the Application of Columbia Gas of Kentucky, Inc. to Extend its Gas Cost Incentive Adjustment Performance Based Rate Mechanism,* and Case No. 2020-00378, *In the Matter of Electronic*

Application of Columbia Gas of Kentucky, Inc. to Extend its Gas Cost Incentive Adjustment Performance Based Rate Making Mechanism.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to support certain filing requirements prescribed by the Commission's regulations including 807 KAR 5:001 Section 16-(7)(a), as well as the proposed modifications to Columbia's tariff pages set forth in Schedule L according to 807 KAR 5:001 Sections 16-(1)(b)3 and 807 KAR 5:001 Section 16-(1)(b)4. My testimony will provide a narrative description and explanation of all the proposed tariff changes in compliance with 807 KAR 5:001 Section 16-(8)(l). The proposed revised tariff sheets are filed pursuant to 807 KAR 5:011. In addition, my testimony will address the requirement of KRS 278.2205 that requires the filing of a cost allocation manual for nonregulated activity as part of the initial filing requirement for an adjustment in rates pursuant to KRS 278.190. Finally, I will support the proposed revisions to Columbia's tariff pages for the Tax Act Adjustment Factor and gas quality standards.

Tariff Revisions

Q: What are the tariff changes that Columbia has included in Schedule L?

A: The changes proposed on Tariff Sheet Nos. 5, 6, 7, 7a, 11, 14, 22, 31, 38, 41 and 58 are base rate changes. These changes are supported by the revenue requirement contained in the testimony of Columbia witness Gore and the rate design contained in the testimony of Columbia witness Johnson.

The changes proposed on Tariff Sheet Nos. 2, 7a, 22, 31, 68, 69 and new Tariffs Sheets 69a- 69c are further explained in my testimony.

Q: Are you sponsoring testimony on any tariff changes?

A: Yes. Columbia is requesting the following changes:

- Tariff Sheets 2, 22 and 31 - Proposed change is a change in text that updates identification of Tariff Sheet No. 58 from Accelerated Main Replacement Program ("AMRP") to Safety Modification and Replacement Program ("SMRP") to match the revision that was authorized by Commission Order dated November 7, 2019 in Case No. 2019-00257.
- Tariff Sheet 7a - Modification of the Tax Act Adjustment Factor ("TAAF") to be utilized to implement the effects due to future changes of the federal and/or state income tax rates on the most recently approved base rates, which could be a collection from custom-

ers or a pass back to customers as described in the testimony of Columbia witness Harding. The tariff will be set at zero until the effective date of a new federal and/or state income tax rate.

- Tariff Sheet 58 – Proposed rates for the SMRP Rider reflect the roll-in of the current year revenue requirement into base rates. Columbia's request to permit inclusion of replacement of older plastic pipe susceptible to brittle-like cracking in the calculation of the SMRP Rider revenue requirement does not require any additional tariff changes.
- Tariff Sheets 68-69c - Modification of the Gas Quality standards to provide for a more detailed list of particulate and chemical compounds and levels that Columbia will require any gas to meet when introduced to its system. These standards provide for a more formalized gas quality testing methodology to ensure that any supplier providing gas to Columbia's system has a clear understanding of testing requirements. Finally, the standards set forth the multiple origins of natural gas supply and define which chemical and particulate standards would likely apply to the natural gas origin. Tariff Sheets No. 69a, 69b and 69c are new original pages created for the gas quality specifications and testing provision additions to Section

18 Gas Quality of Columbia's tariff. The existing language of Section 19 Possession of Gas and Warranty of Title moves from Sheet No. 69 to new original Sheet No. 69c.

Additional Details

Q: How does Columbia propose to address subsequent revisions to Rider SMRP charges?

A: Subsequent revisions to Rider SMRP charges will follow the requirements set forth in the tariff, except that because Columbia is utilizing a fore-casted test year per KRS 278.192, there will likely not be an SMRP Rider filing for October 2021 or a March 2023 Balancing Adjustment filing. If a roll-in is approved, Columbia's next SMRP filings will be in March 2022 for the Balancing Adjustment and in October 2022 for work to be per-formed in 2023.

Q: Why does Columbia propose to address the quality of natural gas on its system?

A: Columbia proposes to incorporate gas quality standards that align with its primary interstate pipeline supplier and will allow Columbia to have a more comprehensive gas quality standard dependent upon the origin of natural gas entering its system. The changes provide a more detailed list of particulate and chemical compounds and levels that Columbia will require any gas to meet when introduced to its system.

Q: Does Columbia propose any new rates or charges associated with the revised gas quality requirements?

A: No, there are no new or increased charges or rates associated with the gas quality changes. The changes provide a more formalized gas quality testing methodology to ensure that any supplier providing gas to Columbia's system has a clear understanding of testing requirements and responsibility.

Q: Please explain Columbia's non-regulated activity as it relates to the filing requirement of KRS 278.2205(6) that requires the filing of a cost allocation manual for nonregulated activity as part of the initial filing requirement for an adjustment in rates pursuant to KRS 278.190.

A: Columbia does not maintain a cost allocation manual pursuant to the exemption provisions of KRS §§ 278.2203 and KRS 278.2205. The only non-regulated activity that Columbia engages in is the provision of incidental billing services for two entities that were previously affiliates, but sold in

2003 and are no longer affiliates. Columbia's rendering of billing services is "incidental" as defined in KRS § 278.2203(4), and Columbia is not required to file a cost allocation manual.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony.

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimony of Jeffrey T. Gore attached. Please also see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky's President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

Jeffrey T. Gore

Columbia Exhibit No. 20

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

PREPARED DIRECT TESTIMONY OF
JEFFERY GORE
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 28, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	
	)	

VERIFICATION OF JEFFERY GORE

STATE OF OHIO	)
	)
COUNTY OF FRANKLIN	)

Jeffery Gore, Regulatory Manager for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that he has supervised the preparation of his Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Jeffery Gore

The foregoing Verification was signed, acknowledged and sworn to before me this 18th day of May, 2021, by Jeffery Gore.

John R Ryan III
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

Notary Commission No. N/A

Commission expiration: N/A

PREPARED DIRECT TESTIMONY OF JEFFERY T. GORE

Q: Please state your name and business address.

A: My name is Jeffery T. Gore and my business address is 290 West Nationwide Blvd., Columbus, Ohio 43215.

Q: What is your current position and what are your responsibilities?

A: I am a Regulatory Manager for NiSource Corporate Services Company ("NCSC"). I am responsible for supporting the NiSource gas utilities in a variety of informational and rate filings, general rate case preparation and support, and other duties as assigned. At this time, my primary focus is on matters for Columbia Gas of Kentucky, Inc. ("CKY" or the "Company") and Columbia Gas of Ohio, Inc.

Q: What is your educational background?

A: I graduated from The Ohio State University with a Bachelor of Science in Business Administration degree, double majoring in Accounting and Computer Science. I have a non-practicing Certified Public Accountant license.

Q: What is your employment history?

A: I have over 30 years work experience with the Columbia Gas Companies primarily within the Accounting and Regulatory departments. Within Accounting, my roles have varied from analyst and manager roles with Columbia distribution companies to Controller - NiSource Service Company & Asset Accounting. Between 2010 and 2015, I was a Regulatory Manager focusing on Columbia Gas of Massachusetts, Columbia Gas of Pennsylvania, and Columbia Gas of Maryland matters. I returned to the Regulatory department in the manager role in October 2018. In early 2021, my responsibilities were changed to include a focus on CKY.

Q: Have you previously testified before the Kentucky Public Service Commission ("PSC")?

A: I provided written direct and rebuttal testimony in Case No. 2002-00145 regarding Other Employee Postretirement Benefit matters.

Q: Have you previously testified before any other Utility Commissions?

A: I have provided direct and written testimony before the Massachusetts Department of Public Utilities on multiple occasions supporting the revenue requirement, including the cost of service and rate base, in the base rate cases, pension expense factor and targeted infrastructure reinvestment filings. Additionally, I have provided written testimony supporting the revenue requirement in the Columbia Gas of Pennsylvania and Columbia Gas of Maryland base rate cases.

Q: What is the purpose of your testimony in this proceeding?

A: My testimony will provide support for the calculation of the requested revenue requirement in the Financial Summary. Additionally, I will support the development of Rate Base Summary, Operating Income Summaries, Summary of Income Adjustments as well as other financial data included in the case. As part of the development of these items, certain sections of the financial data will be supported by other Columbia witnesses as noted in the details of this testimony.

Q: What is the test period in this proceeding?

A: Columbia is requesting an adjustment in rates based on a forecasted test period ("FTP"). The FTP is the twelve months ended December 31, 2022. The financial data for the forecasted period is presented in the form of pro forma adjustments to a base period ("BP") which is the twelve months ended August 31, 2021. The BP period includes actual data for the period

September 1, 2020 through February 28, 2021, and forecasted data for the period March 1, 2021 through August 31, 2021.

Q: What Schedules are you are supporting in this filing?

A: I will be supporting Schedules A, C, F, H and K and will share support of Schedules B, D and I with other Columbia witnesses. Additionally, I also sponsor and support the following Filing Requirements:

Filing Requirement	**Description**
807 KAR 5:001 Section 16-(6)(a)	Financial Data
807 KAR 5:001 Section 16-(6)(b)	Forecasted Adjustments
807 KAR 5:001 Section 16-(6)(c)	Capital, Net Investment Rate Base
807 KAR 5:001 Section 16-(6)(f)	Reconciliation of Rate Base and Capital
807 KAR 5:001 Section 16-(7)(c)	Factors Used in Preparing Forecast
807 KAR 5:001 Section 16-(7)(h)	Financial Forecasts
807 KAR 5:001 Section 16-(7)(h)4	Revenue Requirement
807 KAR 5:001 Section 16-(7)(h)12	Rate Base
807 KAR 5:001 Section 16-(7)(j)	Stock or Bond Prospectuses
807 KAR 5:001 Section 16-(7)(k)	FERC Form 2
807 KAR 5:001 Section 16-(7)(l)	Annual Reports to Shareholders

807 KAR 5:001 Section 16-(7)(m)	Current Chart of Accounts
807 KAR 5:001 Section 16-(7)(p)	SEC Reports (10-Ks, 8-Ks, 10-Qs)
807 KAR 5:001 Section 16-(7)(q)	Independent Auditor's Report
807 KAR 5:001 Section 16-(7)(r)	Quarterly Reports to Stockholders
807 KAR 5:001 Section 16-(7)(t)	Computer, Software, Hardware, etc.
807 KAR 5:001 Section 16-(8)(a)	Financial Summaries
807 KAR 5:001 Section 16-(8)(b)	Rate Base Summaries
807 KAR 5:001 Section 16-(8)(c)	Operating Income Summaries
807 KAR 5:001 Section 16-(8)(d)	Summary of Income Adjustments
807 KAR 5:001 Section 16-(8)(f)	Summary of Membership Dues, etc.
807 KAR 5:001 Section 16-(8)(g)	Summary of Annual Payroll Costs
807 KAR 5:001 Section 16-(8)(h)	Gross Revenue Conversion Factor
807 KAR 5:001 Section 16-(8)(i)	Comparative Income Statements, etc.
807 KAR 5:001 Section 16-(8)(k)	Financial Data and Earnings Measures

Q. For each of the documents included within the Filing Requirements that you are supporting, were they prepared by you or someone working under your supervision?

A. Yes.

SCHEDULE A – FINANCIAL SUMMARY [807 KAR 5:001 Section 16-(8)(a)]

Q: What information is provided in Schedule A?

A: Schedule A provides the overall revenue requirement calculation for the FTP based on inputs from Schedules B, C, H and J. The overall revenue requirement is $174,059,847, which represents a $26,694,986 increase over revenues generated from existing tariff rates. The Schedule B, C and H information will be further developed in this testimony. Schedule J – Cost of Capital was provided by Columbia Witness Rea and supported in his testimony as well as the testimony of Columbia Witness Cole.

SCHEDULE B – RATE BASE SUMMARY [807 KAR 5:001 Section 16-(8)(b)]

Q: What information is provided with Schedule B?

A: Schedule B provides a summary and support for the calculation of Rate Base for the BP and FTP.

Q: What are Rate Base Schedules that you are supporting?

A: I support Schedules B-1, B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-4, B-5, B-5.1, and B-7 for the BP ending August 31, 2021, and the FTP ending December 31, 2022. Additionally, I have included and support Workpapers WPB 2.2 Plant Detail, WPB 2.1 Base Period, WPB2-1 13 month average, WPB 2.2a Intangible Asset, WPB-3.1 AD&A (Base), WPB-3.1 Adj AD&A (Forecast), WPB-5.1 M&S and Prepayments, and WPB 5.3 Storage.

Q: What Rate Base Schedules are supported by other Columbia witnesses?

A: Columbia Witness Harding will be supporting Schedule B-6 Deferred Credits and Accumulated Deferred Income Taxes. Columbia Witness Johnson will be supporting Schedule B-5.2 Cash Working Capital.

Q: Please describe the rate base information presented in Schedule B.

A: The information shown on Schedule B-1 is the jurisdictional rate base summary proposed in this proceeding. The FTP Rate Base was developed using thirteen month average balances of forecasted plant-in-service, reserve for accumulated depreciation and amortization, accumulated deferred income taxes and deferred credits, and working capital items from December 31, 2021 through December 31, 2022, unless noted otherwise. This is consistent with the methodology used by Columbia – and accepted by the Commission - to develop rate base in Case No. 2016-00162.

The plant-in-service and reserve for accumulated depreciation and amortization for the BP and FTP are summarized on Schedules B-2, B-3, and B-4. Forecasted monthly capital additions, with the exception of IT software additions, are based on Columbia's capital budget as supported in the testimony of Columbia Witness Roy plus other planned capital initiatives that are not yet included in Columbia's current capital budget.

Subsequent to the development of the IT software additions forecast, a more granular IT project plan was created that provided a different timing for the in-service dates of the IT investments. The filing has been adjusted to reflect the more current granular view of IT additions and results in an approximately $500,000 reduction in the FTP 13-month average plant in service.

The forecasted monthly reserve for accumulated depreciation balances are based on current depreciation rates through December 31, 2021 and depreciation rates as supported in the testimony of Columbia Witness Spanos for the FTP. In addition to the proposed depreciation rates, the FTP also includes the recommended Reserve Amortization Adjustments that are supported by Columbia Witness Spanos. The forecasted monthly reserve or accumulated amortization balances are based on actual and projected amortizable plant-in-service such as intangible plant.

The allowance for working capital as summarized on Schedule B-5 includes Working Capital Components as well as the Cash Working Capital.

Accumulated deferred income taxes and deferred credits are summarized on Schedule B-6 as supported in the testimony of Columbia Witness Harding.

The jurisdictional percentages are summarized on Schedule B-7.

Q: Why is a thirteen month average balance utilized for rate base?

A: Since Columbia is filing a forecast test period rate case, a thirteen month average calculation was used to comply with Filing Requirement Section 16-(6)(c).

Q: What are Columbia's planned capital initiatives that are not yet included in its current capital budget but which are included in the calculation of rate base?

A: Columbia Witness Roy supports the capital investment in training facilities totaling $5,590,000 that was not part of the approved capital budget. The investment is included in the Rate Base as an in-service addition in November 2022. Additionally, the depreciation expense calculation includes the associated November and December depreciation associated with this investment.

Q: Have you made any other adjustments to the Plant balances that are included in the calculation of rate base?

A: Yes. An adjustment was made to add $2.6 million to 2021 in-service additions to account for the 2020 capital spend that did not get placed into service as portrayed in the forecast. Therefore, this adjustment is necessary to add this amount into 2021 additions in order to align the December 2022 plant investment with the forecast.

Q: Do you have any new Gas Plant Accounts since the last rate case that are included in the calculation of rate base?

A: Yes. Within the 303 Intangible Assets detailed in the workpapers, Account 303.99 is shown separately to identify Cloud Computing Investments.

These assets are capitalized in Plant and amortized over the life of the service contracts (which is generally 5 years) on the accounting guidance provided by the Federal Energy Regulatory Commission ("FERC").

Q: Can you provide the FERC accounting guidance supporting this accounting treatment?

A: Yes. Please refer to Attachment JTG-1.

Q: Please describe in detail the individual supporting schedules for Schedule B.

A: Schedule B-2 shows Columbia's plant-in-service investment by major property grouping for the base period and the forecasted test period. Schedules B-2.1 through B-2.7 provide detail of the major property groupings by gas plant account and show the plant additions and retirements for each account during the base period and forecasted test period.

Workpaper WPB-2.1 provides the monthly balances of plant-in-service by gas plant account for the base period and forecasted test period.

Schedule B-3 shows the accumulated depreciation and amortization balances by gas plant account for the base period and the forecasted test period.

Workpaper WPB-3.1 provides the monthly balances of accumulated depreciation and amortization by gas plant account for the base period and forecasted test period.

Schedule B-4 shows the amount of construction work-in-progress ("CWIP") as of February 28, 2021. The CWIP amounts are not included in the requested Rate Base.

Q: How was the forecasted test period plant-in-service developed?

A: Calculations showing the development of the forecasted monthly plant-in-service balances are found in WPB-2.2. Actual per books plant-in-service as of February 28, 2021 includes amounts in Accounts 101 and 106. Budgeted plant additions were then added by month and budgeted retirements were deducted by month through the forecasted test period. Monthly budgeted capital additions were based on Columbia's capital budget discussed in the testimony of Columbia Witness Roy and further adjusted for the IT software, training facilities, and 2020 In-Service timing investments discussed previously in my testimony. Projected plant retirements were based on a three year average level of actual retirements recorded in 2017 through 2019 with the exception of IT software investments which were analyzed on an individual project basis.

Q: How was the forecasted test period reserve for accumulated depreciation and amortization developed?

A: Calculations showing the development of the forecasted monthly reserve for accumulated depreciation and amortization balances are found in WPB-2.2. Details supporting the monthly amortization expense are found in WPB-2.2a for intangible plant that is subject to amortization. Actual per books accumulated depreciation and amortization as of February 28, 2021 is the starting point of the forecast. For each month of the forecast, the accumulated reserve is increased by the projected depreciation and amortization expense and reduced by the projected retirements and cost of removal. The forecasted depreciation expense is based on current depreciation rates through December 31, 2021 and the depreciation rates supported by Columbia Witness Spanos for the forecasted test period.

Q: How was the Allowance for Working Capital calculated in Schedule B-5?

A: The Working Capital Components were developed using a 13 month average of month end balances for Materials and Supplies and Storage as detailed in WPB-5.1 and WPB-5.3, respectively. Please refer to Columbia Witness Johnson's testimony for support of the Cash Working Capital.

Q: Did Columbia include customer advances for construction as a reduction to rate base?

A: Yes. Since January 2000, a credit is made to gas plant-in-service in recognition of customer advances. Accordingly, a reduction to rate base has been included for post-1999 customer advances by including net plant-in-service per books. Prior to January 2000, a credit for customer advances was included in Account 252. As of February 28, 2021, the balance in Account 252 is zero. The budgeted capital expenditures supported by Columbia Witness Roy are also net of projected customer advances. Therefore, the plant-in-service claimed in this proceeding reflects deductions related to customer advances.

Q: Please explain Schedule B-7.

A: This schedule identifies the allocation factors used to determine the jurisdictional percentage of gas plant costs applicable to the calculation of the gas rate increase requested in this proceeding. Columbia does not have any non-jurisdictional gas customers within its service territory. Therefore, this schedule shows that 100 percent of Columbia's costs are jurisdictional in nature and are appropriate to include for recovery in this proceeding.

SCHEDULE C – JURISDICTIONAL OPERATING INCOME SUMMARY [807 KAR 5:001 Section 16-(8)(c)]

Q: What information is provided in Schedule C?

A: Schedule C presents Columbia's jurisdictional Operating Income for the BP and FTP and details how Columbia derived the amount of the requested revenue increase. Schedule C-1 is the Operating Income Summary, Schedule C-2 represents annual Operating Revenues and Expenses by Accounts – Jurisdictional, and Schedule C-2.2 is the monthly Operating Revenues and Expenses by Accounts – Jurisdictional.

Q: Please explain Schedule C-1.

A: Schedule C-1 reflects Columbia's BP and FTP Operating Income Summary. This schedule includes the FTP operating income summarized at both current rates and proposed rates. The FTP operating income at current rates is presented as pro forma adjustments to the BP. The revenue at proposed rates was developed by adding the revenue increase shown on Schedule A to the current forecasted period operating revenues. The related increase to expenses and taxes on the proposed revenue increase was subtracted from the current adjusted operating results to determine the forecasted operating income and the corresponding rate of return. The rate base as shown on this schedule is calculated on Schedule B-1.

Q: What is Schedule C-2?

A: Schedule C-2 shows the adjusted operating income statement for the BP and FTP at current rates.

Q: Please explain Schedules C-2.1A and C-2.1B.

A: Schedule C-2.1A shows the detail of Columbia's unadjusted BP operating results and Schedule C-2.1B shows the unadjusted FTP operating results.

The operating results as shown on this schedule are listed by account and are summarized on Schedule C-2.

Q: Please explain Schedules C-2.2A and C-2.2B.

A: Schedules C-2.2A and C-2.2B show the information presented on Schedules C-2.1A and C-2.1B, respectively, by month.

SCHEDULE D – SUMMARY OF INCOME ADJUSTMENTS [807 KAR 5:001 Section 16-(8)(d)]

Q: What information is provided in Schedule D?

A: Schedule D presents various adjustments made to BP Operating Income to arrive at FTP Operating Income. Schedule D-1 summarizes by Account the adjustments detailed in Schedule D-2.

Q: Please describe the adjustments included in Schedule D-2.

A: Schedule D-2.1 shows the detailed adjustments made to revenue and gas purchase accounts and is supported by Columbia Witness Siegler. Schedule D-2.2 shows the detailed adjustments made to O&M accounts and is supported by Columbia Witness Lai. Schedule D-2.3 shows the detailed adjustments made to Depreciation and Amortization and Taxes Other Than Income Taxes accounts and is also supported by Columbia Witness Lai. Schedule D-2.4 shows ratemaking adjustments that are being made to the forecasted test period that are in addition to those adjustments on Schedules D-2.1 through D-2.3.

Q: What types of adjustments are included in Schedule D-2.4?

A: While the purpose and description for each adjustment are detailed in Schedule D-2.4, the adjustments reflect ratemaking adjustments to the forecasted expense.

Adjustments 1, 3 and 5 align expense items that generally follow revenues to the new revenues requested in the filing.

Adjustment 2 requests amortization treatment of costs not included in the forecast.

Adjustment 4 replaces budgeted costs with a historic trend of actual costs as this item fluctuates each year.

Adjustment 6 updates property tax expense with updated taxable asset values.

Adjustments 7, 8 and 9 remove non-recoverable items from expense using 2020 actual information as a proxy to estimate the non-recoverable costs in the FTP.

Adjustments 10, 12 and 13 reflect additional expense for initiatives proposed by Columbia Witness Roy.

Adjustment 11 reflects additional expense for an initiative discussed later in my testimony regarding credit card fees.

Adjustment 14 reflects adjustments to the Incentive Plan expense and associated payroll taxes supported by Columbia Witness Lai.

Adjustment 15 reflects adjustments to the NCSC management fee expense supported by Columbia Witness Taylor.

Adjustment 16 reflects COVID deferrals that will be discussed later in my testimony.

Adjustment 17 reflects the change needed to revenue to ensure the uncollectible gas cost recovery aligns with the updated uncollectible rate per Attachment JTG-2.

Q: What is the basis used for determining the current net-charge off percentage used in Schedule D-2.4 Adjustment 1?

A: Please reference Attachment JTG-2 that details the calculation of the bad debt provision rate of .428% used in the uncollectible expense adjustment. This attachment provides the bad debt provisions for years 2017, 2018, 2019 and 2020. The 2020 net charge off rate is much higher due to the pandemic and is not used in the calculation of the bad debt provision rate. Rather the three year average of the bad debt provisions for years 2017, 2018 and 2019 are used to calculate the .428% proposed in this filing.

Q: How are the income tax effects of the D Schedule adjustments reflected?

A: State and federal income taxes have been adjusted on Schedule E-1, which is supported by Columbia Witness Harding, to reflect changes resulting from the adjustments described in my testimony.

SCHEDULE F – OTHER EXPENSES[807 KAR 5:001 Section 16-(8)(f)]

Q: What information is provided in Schedule F?

A: Schedule F is a listing of organization membership dues; charitable contributions; expenditures at country clubs; expenditures for employee gatherings and outings; employee gift expenses, some of which are excluded from

Cost of Service; marketing, sales, and advertising expenditures; professional service expenses; rate case expenses; and civic and political activity expenses for the base period and forecasted test period.

SCHEUDLE H – GROSS CONVERSION FACTOR [807 KAR 5:001 Section 16-(8)(h)]

Q: What information is provided in Schedule H?

A: Schedule H details the factor used to determine the incremental revenue required to cover income taxes, uncollectible expense and PSC fees when a change is recommended to operating income. The uncollectible expense factor, as described earlier in this testimony, is calculated on Attachment JTG-2.

SCHEDULE I – STATISICAL DATA [807 KAR 5:001 Section 16-(8)(i)]

Q: What information is provided in Schedule I?

A: Schedule I, which is co-sponsored by Columbia Witness Lai, provides comparative income statements, revenue statistics, and sales statistics for the five most recent calendar years from the application filing date, the base period, the forecasted test period, and two projected calendar years beyond the forecast period.

SCHEDULE K – COMPARATIVE FINANCIAL DATA [807 KAR 5:001 Section 16-(8)(k)]

Q: What information is provided in Schedule K?

A: Schedule K provides comparative financial data and earnings measures for the ten most recent calendar years, the base period, and the forecasted test period.

CREDIT CARD FEES

Q: Please describe the credit card fee initiative.

A: This initiative will provide customers the opportunity to pay bills with credit cards utilizing the web portal without having incremental fees. Rather the fees would be charged to Columbia and included in the cost of service.

Q: How does this initiative differ from the credit card fee initiative proposed in the prior rate case?

A: The initiative is basically the same as proposed in the prior rate case.

Q: Why are your proposing this credit card initiative again?

A: While the settlement agreement approved in the last case did not provide for this initiative, this initiative has been approved in several of the NiSource jurisdictions. As society moves towards an increasingly cashless system of commerce, consumers expect that transaction fees associated with credit cards and other forms of electronic payment are absorbed by merchants and embedded in product pricing. Very few customers today are still charged a separate transaction fee for credit card purchases and, to the extent that Columbia continues to charge this fee, it will remain within an increasingly smaller segment of merchants who do so. Credit card transaction fees are a cost of doing business and fundamentally no different than other forms of payment options that have their own cost structure. The proposal to eliminate the charge for credit card transactions and embed these costs in the overall cost of service will eliminate a point of friction for customers and allow all costs associated with payment options to be treated equally. As the methods for making payments proliferate due to technological advances, it is important that Columbia remain current and stay attuned to customer expectations for service.

Q: What amounts are you proposing to cover this credit card initiative?

A: Please refer to Attachment JTG-3. Based on history obtained from other NiSource jurisdictions, the cost of the expected customers utilizing this payment option are calculated and offset by the costs that would discontinue as customers switch from other payment options.

COVID COSTS

Q: Please describe the COVID costs that are being included in the Cost of Service.

A: The costs reflect the carrying charges related to financing the arrearage payment plans accumulated between March 16, 2020 and October 1, 2020. The deferral of financing charges related to the arrearage payment plans were approved in a PSC Order dated September 21, 2020 in Case No. 2020-00085.

Q: What amounts are included for recovery?

A: The costs accumulated through April 2021, totaling $33,954, are the total costs requested at this time. The FTP costs reflect 1/3rd of this total as the recovery is requested over 36 months. This amount will continue to be updated throughout the rate case procedural schedule as additional months of actual carrying costs become available.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony if necessary.

ATTACHMENT JTG-1
FERC ACCOUNTING GUIDANCE

FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. AI20-1-000
December 20, 2019

TO ALL JURISDICTIONAL PUBLIC UTILITIES AND LICENSEES, NATURAL GAS COMPANIES, AND CENTRALIZED SERVICE COMPANIES

Subject: Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract

The Financial Accounting Standards Board (FASB) has issued Accounting Standards Update (ASU) No. 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement,* to reduce potential diversity in practice in accounting for the costs of implementing cloud computing arrangements that are service contracts. ASU No. 2018-15 aligns the accounting for costs incurred to implement a cloud computing arrangement that is a service contract with the guidance on capitalizing costs associated with developing or obtaining internal-use software. Specifically, ASU No. 2018-15 clarifies that an entity obtaining a service contract in a cloud computing arrangement should follow the existing guidance in Accounting Standards Codification (ASC) 350-40 to determine which implementation costs can be capitalized and which costs must be expensed, and further provides that the capitalized implementation costs shall be amortized over the term of the associated arrangement. In addition, ASU No. 2018-15 requires the capitalized implementation costs to be reported on the balance sheet in the same line item as any prepayment of the service fees for the associated cloud computing arrangements. The related amortization expense is required to be reported in the same expense line item on the income statement as the expense for the service fees of the associated cloud computing arrangement. For most jurisdictional entities, ASU No. 2018-15 is effective January 1, 2020 for accounting and financial reporting under generally accepted accounting principles (GAAP).

Commission staff received many inquiries from industry participants regarding clarification on how to apply ASU No. 2018-15 within the framework and regulatory intent of the Commission's existing accounting requirements. As discussed herein, for regulatory accounting and reporting to the Commission, jurisdictional entities will be permitted to capitalize certain implementation costs and to amortize those costs over the term of the associated cloud computing arrangement. However, in capitalizing these costs, jurisdictional entities must adhere to the regulations related to plant construction costs set forth under Part 101, Part 201, and Part 367 of the Commission's regulations.[1] Jurisdictional entities must also follow the guidance provided herein with regards to the accounts they should use to record the capitalized costs and the related amortization expense. Service fees and other non-capital costs for the cloud computing arrangement are generally recorded as an expense.

The accounting guidance included herein is intended to result in consistent accounting for the same types of costs incurred for cloud computing arrangements and internal-use software projects for accounting and financial reporting to the Commission. The Commission's accounting requirements are not intended to automatically reflect changes in FASB's Accounting Standards Codification, and FASB updates should not be construed as required for regulatory accounting and reporting to the Commission. However, upon analysis, the Commission may issue accounting guidance to clarify how provisions of an ASU can be reflected within the Commission's existing accounting and financial reporting requirements. Accordingly, this accounting guidance is intended to provide clarity and certainty on how jurisdictional entities should apply the Commission's accounting and reporting requirements related to cloud computing arrangements in response to ASU No. 2018-15.

1. **Question:** How should jurisdictional entities capitalize implementation costs related to cloud computing arrangements?

Response: Implementation costs related to cloud computing arrangements are similar to the costs incurred to develop internal-use software and should be accounted for on the same basis. Jurisdictional entities have historically determined capitalizable internal-use software costs in a manner consistent with the requirements of ASC 350-40, which is an acceptable approach for accounting and financial reporting to the Commission. Accordingly, it is also appropriate for jurisdictional entities to determine capitalized implementation costs related to cloud computing consistent with ASC 350-40. Examples of implementation costs that may be capitalized include upfront costs to integrate with on-premise software, coding, configuration, and customization.

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[1] *See* 18 C.F.R. Part 101, Electric Plant Instructions No. 3 (Components of Construction) and No. 4 (Overhead Construction Costs). *See also* 18 C.F.R. Part 201, Gas Plant Instructions No. 3 (Components of Construction) and No. 4 (Overhead Construction Costs). *See also* 18 C.F.R. Part 367, Service Company Property Instructions No. 367.51 (Components of Construction) and No. 367.52 (Overhead Construction Costs).

2. **Question:** What accounts should jurisdictional entities use to record capitalized implementation costs related to cloud computing arrangements for Commission accounting and reporting purposes?

Response: Jurisdictional entities should record capitalized implementation costs associated with cloud computing arrangements as a utility plant asset, consistent with the Commission's accounting requirements for internal-use software. Accordingly, jurisdictional entities should record capitalized implementation costs in Account 303 (Miscellaneous Intangible Plant), provided such costs are not specifically provided for in other utility plant accounts. For example, public utilities are required to record software used to support regional transmission and market operations in Account 383 (Computer Software). Accordingly, a public utility's capitalized cost related to cloud computing arrangements for regional transmission and market operations should be recorded in Account 383.

3. **Question:** What accounts should jurisdictional entities use to record the amortization or depreciation of capitalized implementation costs related to cloud computing arrangements for Commission accounting and reporting purposes?

Response: Jurisdictional entities should amortize or depreciate capitalized cloud computing costs consistent with the requirements of the utility plant accounts in which they are recorded. Specifically, the amortization of capitalized cloud computing costs recorded as intangible utility plant should be recorded in Account 404 (Amortization of Limited-Term Electric Plant)[2] for public utilities and centralized service companies, and Account 404.3 (Amortization of Other Limited-Term Gas Plant) for natural gas companies.[3] The amortization of capitalized cloud computing costs not classified as intangible utility plant should be recorded in Account 403 (Depreciation Expense).

If a jurisdictional entity believes that its facts and circumstances warrant the use of alternative accounts other than those prescribed herein to record the capitalized costs and related amortization, the jurisdictional entity should request clarification or approval from the Chief Accountant to use the alternative accounting treatment.

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[2] *See* 18 C.F.R. Parts 101 and 367 (2019).

[3] *See* 18 C.F.R. Part 201 (2019).

The Commission delegated authority to act on this matter to the Director of the Office of Enforcement or his designee under 18 C.F.R. § 375.311 (2019). The Director has designated this authority to the Chief Accountant. This letter constitutes final agency action. Your company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2019).

Sincerely,

Steven D. Hunt

Steven D. Hunt
Chief Accountant and Director
Division of Audits and Accounting
Office of Enforcement

ATTACHMENT JTG-2
PROVISION FOR BAD DEBTS

Columbia Gas of Kentucky
Provision for Bad Debts

Line #	Description	2020	2019	2018	2017
1	Reserve account balance at the beginning of the year	$650,967	$800,986	$278,464	$227,382
2	Charges to reserve (accounts charged off)	($586,474)	($996,737)	($633,572)	($862,351)
3	Credits to reserve account	$248,109	$408,607	$416,529	$357,681
4	Current year provision	$2,522,818	$438,111	$739,565	$555,752
5	Reserve account balance at the end of the year	$2,835,420	$650,967	$800,986	$278,464
6	Total Company Revenue (Excludes Unbilled)	127,764,935	134,813,571	142,429,329	126,334,457
7	Percent of provision to total revenue (Line 4/6)	1.9746%	0.3250%	0.5193%	0.4399%
8	Three Year Average - 2017, 2018 & 2019				0.4280%

ATTACHMENT JTG-3
CREDIT CARD FEES

Columbia Gas of Kentucky
Credit Card Fees

LINE NO.	PURPOSE AND DESCRIPTION	AMOUNT
		$
	PURPOSE and DESCRIPTION: To annualize the "Fee Free" transaction program costs for residential customers.	
	RESIDENTIAL CREDIT CARD, DEBIT CARD, ACH AND CHECK TRANSACTIONS	
1	NUMBER OF ANNUAL TRANSACTIONS	188,944
2	CHECK TRANSACTION FEE	1.35
3	ANNUALIZED RESIDENTIAL CREDIT CARD, DEBIT CARD, ACH AND CHECK TRANSACTIONS (Line 1 x Line 2)	255,074
4	RESIDENTIAL LOCKBOX NUMBER OF ANNUAL TRANSACTIONS REDUCTION	(21,829)
5	TRANSACTION FEE	0.16
6	ANNUALIZED RESIDENTIAL LOCKBOX TRANSACTIONS (Line 4 x Line 5)	(3,493)
7	RESIDENTIAL IN-HOUSE NUMBER OF ANNUAL TRANSACTIONS REDUCTION	(391)
8	TRANSACTION FEE	1.00
9	ANNUALIZED RESIDENTIAL IN-HOUSE TRANSACTIONS (Line 7 x Line 8)	(391)
10	TOTAL ANNUALIZED RESIDENITAL CREDIT, DEBIT CARD, ACH AND CHECK TRANSACTIONS (Line 3 + Line 6 + Line 9)	251,190
	RESIDENTIAL WALK-IN TRANSACTIONS	
11	RESIDENTIAL AUTHORIZED WALK-IN PAYSTATION NUMBER OF ANNUAL TRANSACTIONS	51,466
12	TRANSACTION FEE	0.55
13	ANNUALIZED RESIDENTIAL AUTHORIZED WALK-IN PAYSTATION TRANSACTIONS (Line 11 x Line 12)	28,306
14	RESIDENTIAL AUTHORIZED WALK-IN PAYSTATION NUMBER OF ANNUAL TRANSACTIONS REDUCTION	(3,083)
15	TRANSACTION FEE	0.55
16	ANNUALIZED RESIDENTIAL AUTHORIZED WALK-IN PAYSTATION TRANSACTIONS (Line 14 x Line 15)	(1,696)
17	TOTAL ANNUALIZED RESIDENITAL WALK-IN TRANSACTIONS (Line 12 + Line 15)	26,610
18	TOTAL ANNUALIZED CUSTOMER PAYMENT TRANSACTION EXPENSES (Line 10 + Line 17)	277,800