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April 1, 2024

VIA ELECTRONIC FILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor North
P.O. Box 3265
Harrisburg, PA 17105-3265

Re: PA Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.
Docket No. R-2024-3047014

Dear Secretary Chiavetta:

Enclosed for filing on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia") is Supplement No. 379 to Tariff Gas of Pa. PUC No. 9 ("Supplement No. 379"), issued April 1, 2024, with a proposed effective date of October 1, 2024. Supplement No. 379 is included as Exhibit NP-1 in the enclosed material. Supplement No. 379 is filed pursuant to Section 1307(f) of the Public Utility Code to provide for an annual adjustment and reconciliation of Columbia's gas cost recovery rates. Supplement No. 379 proposes an increase in gas cost recovery rates of $0.01968 /Therm.

Also enclosed are Columbia's Direct Testimony and related exhibits as required by the Commission's regulations. Columbia has provided an explanation of over/under collections for the twelve-month reconciliation period ending January 31, 2024, which is attached as Exhibit 1-F, Schedule 1, to Statement No. 2.

Copies of the enclosed filings will be provided as indicated on the Certificate of Service.

Respectfully submitted,

Michael W. Hassell

Michael W. Hassell

MWH/dmc

Attachments

cc: Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served upon the following persons, in the manner indicated, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

VIA E-MAIL

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Date: April 1, 2024

Michael W. Hassell

Michael W. Hassell

COLUMBIA STATEMENT NO. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)))	
v.	)	Docket No. R-2024-3047014
Columbia Gas of Pennsylvania, Inc.	))	

DIRECT TESTIMONY OF
TINA M. MONNIG

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2024

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Q. Please state your name and business address.

A. My name is Tina M. Monnig. My business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am Manager of Planning, in the NiSource Corporate Services Company ("NCSC") Supply and Optimization Group, providing services to Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company").

Q. Please describe your primary supply related responsibilities.

A. I am responsible for activities related to gas supply and capacity planning, including development of detailed long-range plans, short-term operational plans, and strategies to ensure that reliable gas supplies are available and obtained in a best cost manner. In addition, I am responsible for daily operations related to ensuring that gas supplies, pipeline capacity, storage assets and peaking supplies are used in a manner consistent with the planning processes and objectives described herein. I am also responsible for the development of Columbia's Design Day Forecast ("DDF"), and the maintenance/analyses of the related daily information used in developing the DDF.

Q. Please describe your professional experience along with your educational background.

A. I have been employed with Columbia/NCSC since 1995. From 1995 to 2014, I was a Planning Analyst and Team Leader for the Supply and Capacity Planning Group. During my tenure in these positions, I was responsible for monthly supply plans and portfolio studies, operational reports and development of the DDF. In 2014, I was promoted to Manager Planning, overseeing the supply planning, daily operations and demand forecasting responsibilities of the group.

I hold a Bachelor of Science degree in Industrial Management with a minor in Industrial Engineering from Purdue University.

Q. Have you previously testified before the Pennsylvania Public Utility Commission ("Commission") or any other regulatory agency?

A. Yes, I have previously testified in support of Columbia's 2021, 2022, and 2023 1307(f) filings before the Commission. I have also testified on behalf of Columbia's affiliate company, Columbia Gas of Maryland, Inc., in its annual Purchased Gas Adjustment proceedings before the Maryland Public Service Commission each year from 2015 to the present.

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

A. The purpose of my testimony is to:

I. Describe the interstate pipeline services and capacity Columbia utilizes in its least cost purchasing plan and how this capacity compares to Columbia's policy regarding its portfolio design;

II. Describe the gas supply related activities pertaining to Columbia's Customer CHOICE^{SM} program; and

III. Illustrate Columbia's activity at the Federal Energy Regulatory Commission ("FERC").

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits, which were included with Columbia's pre-filing data submitted on March 1, 2024:

Number	Description	Regulation
Company Exhibit 2	Contacts of Offers Regarding Historic and Projected Sources of Gas Supply	53.64(c)(3)
Company Exhibit 3	Annotated List of Relevant FERC Proceedings	53.64(c)(4)
Company Exhibit 4	Pa. P.U.C. Form 1 Filing	53.64(c)(5)
Company Exhibit 4-A	Explanation of Variance Between Present and Most Recent Estimated Sales Volumes (Form 1)	53.64(c)(5)
Company Exhibit 4-B	Explanation of Variance Between Actual and Estimated Sales Volumes (Form 1)	53.64(c)(5)
Company Exhibit 5	Statement of Fuel Procurement Practices	53.64(c)(6)
Company Exhibit 10	A Schematic System Map	53.64(c)(10)
Company Exhibit 12	Schedule of Most Recent Five Year Three Day Peak Data by Customer Class	53.64(c)(12)
Company Exhibit 13	Identification and Support for Peak Day Methodology	53.64(c)(13)
Company Exhibit 14	Analysis on an Historic and Future Basis of the Minimum Gas Entitlements Needed to Serve Priority One Customers during Peak Periods	53.64(c)(14)
Company Exhibit 15	Report Supporting Capacity – Level of Peak Day Capacity Retained	

In addition to the pre-filing Exhibits that I am sponsoring, I am sponsoring Exhibit TMM-1 and Exhibit TMM-2, which are attached to my testimony. Exhibit TMM-1 shows peak day and annual entitlements, for contract year 2024-25, under Columbia's firm capacity contracts with Columbia Gas Transmission, LLC ("TCO"), Eastern Gas Transmission and Storage, Inc. ("EGTS", formerly Dominion Transmission), Equitrans, L.P. ("Equitrans"), National Fuel Gas Supply Corporation

("National Fuel"), Tennessee Gas Pipeline Company, LLC ("Tennessee" or "TGP"), and Texas Eastern Transmission, LP ("Texas Eastern" or "TETCO"). Exhibit TMM-1 also lists upstream firm pipeline capacity that is utilized to deliver supplies to TCO, namely Tennessee and Texas Eastern. Exhibit TMM-2 shows Columbia's firm peak day supplies and firm demand by contract year.

I. GAS PURCHASING & PROCUREMENT STRATEGIES

Q. Please describe the procedures that Columbia uses to estimate customer requirements. A. For purposes of the estimates used in this Section 1307(f) filing, Columbia has estimated its customers' seasonal requirements by customer class, assuming 20-year normal weather and expected market conditions. Columbia combines base load and temperature sensitive demand to determine monthly residential and commercial customer requirements. The monthly gas space heating demand for residential and commercial customers is derived by forecasting customer count and gas use per customer. The customer count is derived using economic and demographic data (households, gross county product). The use per customer is derived using weather data throughout Columbia's operations territory, and energy intensity. Columbia utilizes a grass roots survey of industrial customers to estimate industrial demand. Columbia then estimates customer participation levels under its various transportation programs. These participation levels are deducted from Columbia's demand estimates to establish projected sales levels.

Q. Does Columbia determine customer demand for conditions other than normal weather?

A. Yes. As more fully described in Company Exhibit 5, for supply planning purposes Columbia determines customer demand under various weather scenarios. Columbia determines customer demand under a colder-than-normal weather scenario to plan its gas supply and capacity portfolio to ensure that it is adequate to meet increased customer demand. Columbia also determines customer demand under a warmer-than-normal weather scenario to plan the flexibility needed in its supply and capacity portfolio to meet reduced customer demand at least cost.

Q. Please describe the conditions Columbia utilizes to define colder-than-normal and warmer-than-normal customer demand.

A. For colder-than-normal demand, Columbia incorporates increased seasonal heating degree-days based upon a 10 percent probability of a colder-than-normal occurrence, a seasonal peak day at design temperature, and late winter design cold days. For warmer-than-normal demand, Columbia reduces winter season normal heating degree-days based upon a 10 percent probability of a warmer-than-normal occurrence. The 10 percent probability level for the colder-than-normal weather scenario means that there is a 10 percent risk that the winter will have more heating degree-days compared to the planned colder scenario. Conversely, the 10 percent probability for the warmer-than-normal weather scenario means that there is a 10 percent risk that the winter will have less heating degree-days compared to the planned warmer scenario. Columbia utilizes normal weather heating degree-days for the summer season in all demand determinations described herein. On a weighted average basis, for Columbia's service territory, approximately 81 percent of the annual heating degree-days for a normal year occur in the five-month winter season (November - March) and 19 percent in the seven-month summer season (April – October).

Q. Please describe the late winter design cold days and their importance.

A. Columbia utilizes late winter design cold days to test the adequacy of its supply portfolio on cold days late in the winter season, after the planned occurrence of the seasonal design day. As storage supplies are withdrawn, the deliverability of natural gas storage fields declines. Pipeline tariffs recognize this decline and reduce withdrawal entitlements in accordance with the volumes remaining in storage. Due to Columbia's heavy reliance upon storage, Columbia utilizes the late winter design cold days to properly manage storage withdrawals and ensure that its capacity portfolio can reliably meet customer demand on such cold late winter days under all planning scenarios, including the colder-than-normal weather scenario.

Q. Please describe the conditions Columbia utilizes to estimate its design day demand.

A. Columbia's design day demand forecast is based upon the following conditions and considerations:

1) the "design" conditions of
    a. current day design temperature;
    b. prior day design temperature;

c. current day design wind speed; and

d. occurrence of the design day on a weekday;

2) an estimate of the number of customers to be served each January for the term of the forecast;

3) forecasted January NYMEX Gas Monthly Price at Henry Hub (NGI Bidweek Prices) for the term of the forecast;

4) actual degree days occurring in the months of December and January for the term of the forecast because these are the two months when Columbia's design conditions are most likely to occur; and

5) average Non-Farm Employment in the months of December through February for the term of the forecast.

All of the above factors influence customer demand on Columbia's system on the current day.

The current and prior day design temperatures were developed utilizing all available historic weather data ending with the winter of 2014-15. Columbia updates these design temperatures approximately every five to ten years. The current day design temperature is determined by utilizing a Gumbel Distribution of the annual minimum daily mean temperatures, with a 1 in 15 or 6.67 percent risk factor. That is, the probability is 6.67 percent that any given winter will have one or more days with a mean daily temperature equal to or colder than the current day design temperature.

The prior day design temperature is determined from the mean temperature difference between historical "cold days" and their associated prior days. "Cold days" are defined as those that are no warmer than the current design day temperature plus 5 degrees Fahrenheit.

The design wind speed is based on an analysis of wind activity for the 1990-91 through 2014-15 winter seasons. Columbia updates this wind speed analysis every five to ten years. This analysis determines the average daily wind speed on days that are no warmer than the current design day temperature plus 15 degrees Fahrenheit.

Columbia then utilizes a multiple variable, linear regression analysis of (1) historic daily demand, temperature and wind speed data to determine the design actual daily demand estimate for the most recent year; and (2) a second multiple variable, linear regression analysis of the estimated historic design actuals, January customer counts (historic and forecast), December/January degree days (actual and normal), average non-farm employment (December through February) and retail gas prices (historic and forecast) to develop its design day forecast.

Q. Does Columbia plan for a date of occurrence of a peak day?

A. Yes, Columbia determines the latest date within a winter season, with a 10 percent probability, that a current day design temperature or colder may occur in Columbia's service area. Columbia analyzes the historical dates of occurrence of peak day or colder temperatures to determine this date. Columbia's current planned latest date of peak day occurrence is January 25th.

Q. Does Columbia plan for dates where storage deliverability can be reduced?

A. Yes, for reliability purposes, Columbia determines the lowest temperatures at which firm customer demand can be satisfied immediately after a reduction in storage deliverability. Once Columbia determines these temperatures, the Company then determines the latest dates, with a 10 percent risk, that these temperatures may occur.

Q. What is the importance of these dates?

A. As noted earlier, the deliverability of natural gas storage fields declines as storage supplies are withdrawn. Under the interstate pipeline storage service tariffs utilized by Columbia, the right to withdraw storage volumes is reduced when specific storage inventory levels are reached. These ratcheted reductions in storage withdrawal entitlements occur in steps. Under the Firm Storage Service ("FSS") tariff of TCO, the first step, which reduces storage withdrawal entitlements to 80 percent of the maximum, is reached when remaining storage inventory is less than 30 percent of the seasonal contract quantity. Two additional steps reduce withdrawal entitlements to 65 percent and 50 percent of maximum. These steps occur when storage inventories fall below 20 percent and 10 percent, respectively. Columbia must manage its storage inventories throughout the winter season to prevent a premature storage deliverability reduction. Such a premature reduction could leave Columbia with insufficient firm supplies to satisfy the demand of firm customers on cold days late in the winter.

II. INTERSTATE PIPELINE SERVICES AND CAPACITY

Q. Please describe Columbia's pipeline services listed on Exhibit TMM-1.

A. As noted on Exhibit TMM-1, for contract year 2024-25, Columbia will receive firm pipeline services from six interstate pipeline companies, namely, TCO, EGTS, Equitrans, National Fuel, Tennessee, and Texas Eastern.

Q. Please describe Columbia's pipeline service from TCO.

A. Columbia contracts for three primary firm services from TCO: Firm Transportation Service ("FTS"), FSS, and Storage Service Transportation ("SST"). The FTS capacity provides for the firm transportation of flowing gas supplies delivered by TCO, either from Appalachian receipt points or interconnects with upstream pipelines, to Columbia's city gates or storage. The FSS capacity provides daily injection and withdrawal capacity into or out of storage, along with firm daily deliverability and seasonal storage capacity. The primary utilization of the SST capacity is providing firm transportation of storage volumes from TCO's storage fields to Columbia's city gates. A secondary use of SST is transporting flowing gas supplies, in excess of Columbia's FTS capacity level, to fill storage during the summer. The use of FSS in conjunction with SST provides Columbia with its primary daily no-notice balancing service.

Q. Please describe the importance of the TCO capacity to Columbia.

A. Natural Gas Distribution Companies ("NGDCs"), such as Columbia, are fully responsible for the delivery of supplies from producers, marketers, and other supply aggregators to fulfill 100 percent of the supply requirements of sales and CHOICE℠ customers. For the majority of Columbia's markets, TCO provides the only physical pipeline connection to facilitate such service. Thus, the use of TCO's facilities is critical to Columbia's ability to provide reliable, economic service to its customers. Further, NGDCs are responsible for balancing all deliveries to their city gates on a daily basis, including those supplies delivered to Columbia on behalf of General Distribution Service ("GDS") customers. Columbia's widespread, discrete service territories, large number of city gates, and highly temperature sensitive customer requirements create unique daily balancing challenges.

Because the vast majority of Columbia's market areas are served only by facilities owned by TCO, Columbia is able to utilize its FSS capacity to balance deliveries and demand to all but a handful of its city gates. Columbia's widespread, discrete service areas, and large number of city gates generally make it uneconomic to construct laterals and interconnections between Columbia and other pipelines. As noted on Exhibit TMM-2, TCO delivers about 84 percent of Columbia's design day supply. As such, Columbia must continue to rely upon it's interconnects with TCO to deliver the majority of supplies necessary to meet the requirements of its markets.

Q. Please describe the pipeline and storage services that Columbia receives from other providers.

A. Columbia has six firm transportation contracts and three storage contracts with EGTS. The first transportation contract, provided under EGTS's rate schedule Firm Transportation No-Notice - General Storage Service ("FTNN-GSS"), for 6,000 Dth per day, is utilized to transport storage supplies from EGTS's storage fields to Columbia's city gates. Storage supplies are also transported to Columbia's city gates via a transportation contract under EGTS's rate schedule Firm Transportation

("FT"). This contract has a quantity of 3,000 Dth per day from November through March of each year, and 2,000 Dth per day from April through October of each year. The associated storage contract with EGTS provides Columbia with 9,000 Dth/day of peak day deliverability and approximately 941,176 Dth of seasonal supply. Columbia utilizes these EGTS contracts to provide supplies to its customers in Beaver County through its Darlington interconnect and in Cranberry Township through its Warrendale interconnect.

Columbia has two additional storage contracts and three FTNN and FT transportation contracts with EGTS that are utilized to meet the demand and balancing requirements in the State College market. The storage contracts provide for daily withdrawal of 15,000 Dth/day and 4,800 Dth/day with seasonal quantities of 930,000 Dth and 240,000 Dth, respectively. Columbia utilizes 19,800 Dth/day of Rate Schedule FTNN transportation capacity to deliver the EGTS storage supplies to the State College market. Additionally, Columbia has 5,000 Dth/day of FT capacity which it also uses to serve the State College market.

Lastly, Columbia has 255 Dth/day of FT capacity with EGTS that provides service to a new interconnection serving the Centre Hall market.

Columbia also contracts for firm transportation and storage service with Equitrans. The storage service provides peak day deliverability of 19,130 Dth and 2,000,000 Dth of seasonal capacity. The maximum winter season city gate deliveries total 55,000 Dth per day including up to 19,130 Dth from storage. Summer capacity levels are sculpted with 32,000 Dth per day in April and October and 20,000 Dth per day May through September.

Columbia utilizes the Equitrans storage service, approximately 9,635 Dth/day of the associated 19,130 Dth/day of the winter season FTS Transportation Quantity ("TQ"), and the EGTS storage service and associated 4,800 Dth/day FTNN transportation contract, discussed above, to provide service to GDS customers under Columbia's Elective Balancing Service ("EBS") Option 1. I will discuss EBS in greater detail later in my testimony.

Columbia currently contracts for firm transportation service with Tennessee totaling 23,600 Dth/day. A total of approximately 19,300 Dth/day is required to serve the design peak day firm customer demand in Columbia markets directly connected to Tennessee, while approximately 4,300 Dth/day is delivered to Columbia's National Fuel capacity. On days when the 19,300 Dth/day delivered directly to Columbia cannot be absorbed by those markets, Columbia can divert that supply to Tennessee interconnects with TCO for injection into storage or delivery to other Columbia markets that are served by TCO.

Columbia contracts for firm transportation service under two rate schedules with Texas Eastern, FT-1 and Comprehensive Delivery Service ("CDS"), totaling 23,635 Dth/day. A total of 20,453 Dth/day is required to serve the design peak day firm customer demand in Columbia markets directly connected to Texas Eastern while 3,082 Dth/day must be delivered to TCO, as an upstream supply, to meet design day demand in Columbia markets served by TCO.

Similar to operations on Tennessee, on days when the 20,453 Dth/day delivered directly to Columbia cannot be absorbed by those markets, Columbia can divert that supply to secondary delivery points off Texas Eastern or to Texas Eastern interconnects with TCO for injection into storage or delivery to other Columbia markets served by TCO. Columbia also contracts for 10,000 Dth/day of winter season, market-area firm backhaul transportation capacity. Columbia utilizes this capacity to satisfy cold weather requirements behind the city gates connected to Texas Eastern.

Columbia contracts for 4,304 Dth/day of city gate capacity under the FTS rate schedule of National Fuel. This capacity is utilized to serve Columbia's Warren market area. In addition, Columbia also has a contract with National Fuel consisting of enhanced firm transportation ("EFT") of 4,000 Dth per day, of which 1,571 Dth per day will be received at the Mercer Interconnection and delivered to the CPA Findlay Township meter station in Allegheny County, while 2,429 Dth per day will be received from National Fuel's storage receipt point and delivered to the new CPA Findlay Township meter station in Allegheny County. Additionally, National Fuel will provide an enhanced storage service ("ESS") with a Maximum Storage Quantity ("MSQ") of 267,143 Dth, a Maximum Daily Injection Quantity ("MDIQ") of 1,571 Dth per day, and a Maximum Daily Withdrawal Quantity ("MDWQ") of 2,429 Dth per day to be used in combination with the EFT service.

As noted earlier, Columbia utilizes portions of its Tennessee contracts to provide supply to the National Fuel capacity. Columbia can divert the Tennessee supplies when not needed to serve National Fuel fed markets for delivery to other Columbia markets served by TCO or injection into storage.

Q. Have there been any changes to Columbia's contracts in the last year?

A. Yes, there have been a few changes to Columbia's contracts from the previous year. CPA acquired the following contracts:

1) 7,000 Dth firm transportation on TGP with a one winter only term of December 1, 2023 through February 29, 2024; and

2) 2,000 Dth firm transportation on TETCO for a term of December 1, 2023 through November 30, 2024.

In addition, CPA entered into a precedent agreement for capacity as a result of an open season on TETCO's Appalachia to Market III (A2M3) offering. The negotiated agreement has a term of 15 years and is for 3,000 Dth/day from November 1, 2027 through October 31, 2028, and 5,000 Dth/day beginning November 1, 2028, for the remainder of the agreement.

Q. Why did CPA enter into these contracts?

A. As discussed in Exhibit 5, CPA entered into these contracts to address market needs. Specifically, the 2,000 Dth on TETCO was to serve the Uniontown area and the 7,000 Dth on TGP was to serve the Warrendale area. Both were needed to meet design day requirements in these areas.

Q. Can you also explain the reason behind entering into a precedent agreement for TETCO A2M3 capacity?

A. Yes, CPA entered into the precedent agreement to meet forecasted growth in the York area. The growth in this market was expected to exceed its supply/capacity by the 2031/32 winter season. CPA took the opportunity to make a bid on the open season for the capacity and to secure the bid with a 15-year agreement beginning in November 2027 for 3,000 Dth/day in the first year and increasing to 5,000 Dth/day.

Q. Were there other alternatives considered in lieu of the TETCO A2M3 capacity?

A. Yes, other alternatives were considered. There was not additional capacity available on TCO into this market area nor did TCO have any expansion projects for this market on the horizon. Additionally, TCO's cost guidance to upgrade their system for equivalent capacity exceeded Columbia's contract obligations under the A2M3 project. Therefore, the A2M3 project is the best option at this time.

Q. Is Columbia considering any other future changes in capacity?

A. Columbia has an ongoing evaluation of alternatives, to the extent they exist, as potential replacements to portions of its existing portfolio become available.

Q. Please summarize Columbia's New and Renewed Capacity process.

A. Columbia's contracts for pipeline storage and firm transportation service each contain specific provisions detailing termination dates, as well as notification dates, wherein Columbia must notify the respective interstate pipeline if it decides to renew the capacity under current contract terms beyond the contract termination date. Approximately 6-9 months prior to this notification date, Columbia determines whether this capacity or its equivalent is required to serve its residential and small commercial customers. Upon determining that the capacity is required, Columbia then determines whether this capacity is also required for system balancing or Supplier of Last Resort ("SOLR") services.

For capacity that is not required for balancing or SOLR services, Columbia prepares a Request for Proposal ("RFP") and submits the RFP to all NGSs who are licensed to conduct business on Columbia's system. This RFP defines the delivery points required by Columbia to receive gas supplies, as well as a general outline of the daily delivery volumes by point of delivery. The qualified NGSs determine if they have a desire to deliver gas supplies to Columbia at these points in the manner required by Columbia to serve its markets utilizing firm primary point capacity. If an NGS determines it has the desire and ability, then it can submit an offer under the RFP. Once received, Columbia will evaluate all offers to determine whether they meet the requirements of the RFP and, if appropriate, compare such offers against other options available to Columbia. If the offer complies with the RFP and is better than other options available to Columbia, the successful NGS and Columbia will enter into an agreement defining the delivery details required to serve the relevant market. This process of offering and accepting an offer from an NGS, along with completion of the delivery agreement, must be completed in a timely manner in order to allow Columbia to terminate the capacity that is the subject of the RFP. In the event that no offer is received under the RFP, Columbia proceeds either to extend the contract under existing terms and rollover rights, if available, or renegotiate the contract.

Q. Did Columbia offer NGSs operating on its system an opportunity during the past year to provide new or replacement capacity under its Acquisition Process for New and Renewed Contracts?

A. Yes, Columbia provided NGSs opportunities during the past year to provide offers of replacement capacity.

Q. Please describe the capacity for which Columbia requested offers from NGSs to replace.

A. Columbia requested replacement capacity offers on capacity as follows:

1) 14,835 Dth of firm transportation on Texas Eastern;
2) 4,304 Dth of firm transportation capacity on National Fuel; and
3) 16,00o Dth 0f firm transportation capacity on Tennessee.

Q. Did Columbia receive any offers of replacement capacity from an NGS?

A. No.

Q. Is the capacity provided pursuant to the contracts for which Columbia requested replacement offers from NGSs required by Columbia?

A. Yes.

Q. Please describe the actions taken by Columbia to renew these contracts.

A. Columbia retained the capacity of each contract by extending the term or exercising its annual rollover rights as follows:

1) Columbia exercised its annual rollover right and retained the capacity under existing contractual provisions for the Texas Eastern contract for 14,835 Dth.

2) Columbia also exercised its annual rollover right and retained the capacity under existing contractual provisions for the National Fuel contract for 4,304 Dth.

3) Columbia exercised its Right-of-First Refusal ("ROFR") and extended the current transportation contract with Tennessee Gas for 16,000 Dth.

Q. Is the firm capacity listed on Exhibit TMM-1 required to meet Columbia's projected design peak day firm requirements?

A. Yes.

Q. Is the firm capacity listed on Exhibit TMM-1 consistent with Columbia's policy regarding the level and mix of its supply/capacity portfolio?

A. Yes. A reconciliation of Columbia's firm peak day capacity entitlement level with Columbia's future years' firm design day demand per Columbia's 2023 Design Day Forecast is provided in Company Exhibit TMM-2. The forecast also shows a maximum hourly design adjustment to the design day demand for this calculation. This adjustment is to account for the potential of hourly flow restrictions on EGTS. This shows that Columbia's current peak day capacity level is within the bounds contained in Columbia's Portfolio Design policy, which provides that Columbia will have sufficient capacity to be within a range of up to 103% of the highest of its projected design day firm requirements for the five-year period of its Design Day Forecast.

Q. Why is it necessary to show an additional demand to account for a maximum hour in the determination of the 103%?

A. The approved settlement agreement of August 15, 2013, that established the policy to have capacity levels within 103% of Columbia's design day demand, was predicated on a daily design/capacity evaluation. In recent years, EGTS has called alerts and operational flow orders at an hourly level. Therefore, Columbia needs the ability to contract in excess of daily design demand in order to comply with an hourly restriction on EGTS. Without recognition of the hourly component in design day demand, Columbia will understate the capacity needed to meet design conditions. In other words, applying the 103% measure without the hourly component may inaccurately show it has capacity in excess of the policy since the maximum hour/daily demand ratio is greater than 1 to 1.

Q. What areas of Columbia's system are served by EGTS?

A. There are three areas served by EGTS: State College, Warrendale and Darlington.

Q. What is the firm design day demand for these areas for 2024/25?

A. The 2024/25 forecasted firm design day is the following:

- 23,698 Dth in State College
- 12,760 Dth in Darlington
- 21,639 Dth in Warrendale

The total across all three markets is 58,097 Dth, which equates to approximately 9% of the total firm design day requirements. As reflected in TMM-2 the maximum hour need is an additional 9,800 Dth which is 16.8% above the associated daily design demand. This significantly exceeds a "3%" limit on a stand-alone basis.

Q. Are these markets solely served by EGTS?

A. No, these markets are served by other pipelines, but EGTS is a significant source in in serving these markets.

Q. Has EGTS recently made tariff changes introducing the ability to impose hourly restrictions in its pipeline?

A. No, this language is not a recent change in their tariff. However, the threat of hourly restrictions has increased in recent winters and in fact an hourly restriction was issued on two separate occasions during winter of 2022/2023, one in December 2022 and one in February 2023, on its PL-1 System, which serves the State College market. EGTS also issued several alert notices for the potential hourly restrictions this past winter.

Q. How does EGTS determine if a customer is in compliance with an hourly restriction?

A. There are 4 tests that EGTS assesses to determine compliance as shown in Section 9.5 of their tariff, which states:

> If Customer's executed Service Agreement specifies an MDDO for a Primary Delivery Point, then during any 24-hour period in which the OFO described in Section 9.5.C. is in effect, Customer shall be limited to the following hourly fluctuations at each point:
>
> 1. 120% of 1/24th of the MDDO in any one hour;
> 2. 115.7% of 3/24ths of the MDDO in any three consecutive hours;
> 3. 112.6% of 5/24ths of the MDDO in any five consecutive hours;
> 4. 104.2% of 12/24ths of the MDDO in any twelve consecutive hours.

In addition, Columbia still needs to be within its daily contract entitlements.

Q. Does EGTS have measurement for Columbia's deliveries on EGTS at an hourly level in order to determine compliance with its hourly flow restrictions?

A. Yes, EGTS has hourly measurement capabilities for deliveries into Columbia's system.

Q. How does EGTS treat Columbia's contracts for the determination of "allowable" hourly fluctuations.

A. EGTS applies the 120%, 115.7%, 112.6% and 104.2% to Columbia's contracts on rate schedule FTNN. These percentages allow for additional flexibility over the 1/24th, 3/24ths, 5/24ths, and 12/24ths contract determinants. However, these percentages are not applied to the FT contracts. See Table 1 for a summary of its contracts and limits for the 120% of 1/24th of the MDDO in any one hour limit:

Table 1 Columbia's EGTS Contracts Treatment for Hourly Flow Limitations (Units in Mdth)

Contract No.	Rate Schedule	Daily Entitlement	1/24th	Hourly Factor applied	120% of 1/24th	Adjusted level for 24 Hour/Daily	Net Increase
200539	FT	3.0	0.1	No	0	3.0	0.0
200687	FT	5.0	0.2	No	0	5.0	0.0
200754	FT	0.3	0.0	No	0	0.3	0.0
100121	FTNN	4.8	0.2	Yes	0.0	5.8	1.0
100122	FTNN	15.0	0.6	Yes	0.1	18.0	3.0
70034	FTNN	6.0	0.3	Yes	0.1	7.2	1.2
All	FT	8.3	0.3	No	0.0	8.3	0.0
All	FTNN	25.8	1.1	Yes	0.2	31.0	5.2

Q. There is an adjustment in TMM-2 that shows a Max hour adjustment to the daily storage capacity on EGTS. Can you explain this adjustment?

A. In order to recognize the additional flexibility described above for Columbia's EGTS contracts it has reflected the 5.2 in Table 1 adjustment for maximum hour to its storage capacity level. S.

Q. Would Columbia have received a penalty during the winter of 2022-2023 if CPA had capacity equal to the actual firm daily throughput?

A. Yes, on December 23, 2023, the firm daily demand was 18,584 Dth in the State College market. If the capacity contracts equaled 18,584 Dth, Columbia would have exceeded its EGTS hourly flow limits on this day and incurred a penalty.

Q. Are there risks, other than penalties, from not having sufficient capacity to serve the maximum hourly requirements?

A. Yes, if CPA's hourly demand exceeds its hourly rights, then EGTS may experience low pressure on their system, which could negatively impact CPA's system to provide reliable service to CPA's customers.

Q. What is Columbia recommending with respect to the determination of its 103% design policy?

A. Columbia is recommending inclusion of the maximum hour adjustment in the calculation of the 103% test. It is critical that Columbia to have enough firm capacity to serve its firm customers across its system in order to provide reliable service.

III. COLUMBIA'S SUPPLY

Q. Please describe how Columbia balances deliveries to all its city gates.

A. Because the majority of Columbia's customers have highly temperature sensitive demand, Columbia's supply portfolio must be able to provide widely varying daily supplies in response to daily changes in temperature.

In order to provide gas supplies on a least cost basis for its customers, Columbia relies heavily upon the daily withdrawal and injection flexibility of its primary storage service provided under TCO's FSS Rate Schedule. TCO's FSS rate schedule provides Columbia with its primary no-notice service. Columbia also has limited no-notice service on Texas Eastern, National Fuel and EGTS.

As noted on Exhibit TMM-1, storage service provides about 67 percent of Columbia's design peak day capacity. Storage service provides Columbia with approximately 60 percent of its normal weather, winter season supply to meet the needs of its firm customers and the vast majority of its system balancing requirements. In addition, the flexibility of Columbia's capacity portfolio including the storage capacity enables it to provide EBS to GDS customers. Storage service contributes to Columbia's ability to provide a least cost gas supply under varying weather conditions. Columbia's storage capacity also provides mitigation of winter season price increases.

While Columbia relies heavily on its storage service to meet changing customer demand, Columbia's contracted storage services do not provide it with the full swing capability it requires to meet the temperature-sensitive demand swings of its customers, particularly on warmer days during shoulder months. Therefore, Columbia incorporates the use of daily spot purchases during these periods. When warranted, Columbia implements the use of "swing" provisions included in its firm gas supply contracts that provide Columbia the opportunity to reduce flowing gas supplies on these warm days yet permit Columbia to increase flowing volumes again once weather turns colder or to meet seasonal demand.

Q. Earlier in your testimony you mentioned Columbia's Elective Balancing Service. Please describe this service and its benefits.

A. EBS provides substantial enhancements to the balancing service Columbia had traditionally provided its GDS customers. EBS provides the following benefits:

1) Provides GDS customers with two balancing service options. Under Option 1, Full Balancing Services, NGSs and customers have the ability to carry banks over from month to month with several service enhancements, which are discussed later in my testimony. Under Option 2, Monthly Cash Out, NGSs and customers choose to be cashed out monthly. A monthly cash out provides customers the opportunity to carry an intra-month bank, but this bank is cashed-out at the end of each month. There are no customers currently electing Option 2.

2) Under EBS Option 1, NGSs and customers are provided firm cold day and warm day Operational Flow Order ("OFO")/Operational Matching Order ("OMO") tolerances. Under cold day OFO/OMOs, NGS or customer deliveries equal to or greater than 95% of actual (OMO) or estimated (OFO) demand are considered to be in compliance with the flow orders, provided that the customer has sufficient gas in its bank. Under warm day OFO/OMOs, NGS or customer deliveries less than or equal to 102.5% of actual (OMO) or estimated (OFO) demand are considered to be in

compliance with the flow order, provided that the customer has sufficient room in its bank to accept the over deliveries.

3) Under EBS Option 1, NGS and customer access to banks is provided on a firm basis, recognizing the daily OFO/OMO limitations noted above, as long as an NGS or customer has a positive bank balance.

Q. Please describe Columbia's capacity release program.

A. Columbia utilizes PLEXOS as its planning software. PLEXOS is used to help evaluate both short and long-term capacity release opportunities. In Columbia's evaluation of the level of capacity to release, Columbia considers the requirements of its retail customers, including storage injection requirements. The total releasable capacity is equal to the difference between Columbia's monthly firm capacity level and the firm customer requirements at the applicable fifth design day (that capacity level which Columbia has determined may be needed for recall on up to 5 days in any given month). SST capacity utilized at secondary receipt and delivery points for injection into storage is also factored into the analysis. Columbia then determines the levels of recallable and non-recallable transportation capacity that is available for release. Non-recallable capacity is equal to the difference between Columbia's monthly firm entitlement level and the firm customer requirements at design day conditions. The monthly recallable capacity is then equal to the difference between the total capacity identified as releasable and the non-recallable component.

Q. Please explain the difference between recallable and non-recallable releases.

A. As the names imply, recallable releases provide the releasor with the ability to recall the capacity under the terms specified in the release agreement and in accordance with the interstate pipeline's tariff recall provisions. Non-recallable capacity releases conversely are not recallable by the releasor during the term of the release. Recallable capacity is generally less valuable to the assignee than is non-recallable capacity due to the interruptible nature of the release.

Q. How does Columbia conduct its economic analysis to develop its gas supply mix and projections of gas supply mix and cost?

A. Columbia's basic tool of analysis is the PLEXOS Gas Planning System provided by Energy Exemplar. PLEXOS determines the "optimum" time-dependent levels of pipeline transportation service and storage service to be utilized to meet Columbia's prospective demand under various weather-related scenarios and recognizes specific demand regions within Columbia's service territory and the pipeline capacity and supply sources that are available to each region. Columbia updates supply prices, storage balances and other input data in PLEXOS on an ongoing basis from a variety of published and private sources. Columbia utilizes PLEXOS for both long-range and short-term operational planning.

Q. In calculating the least cost gas supply analysis, what price information is considered by the model?

A. Columbia prepares a monthly estimate of gas prices for use in its monthly planning process. The estimate generally reflects NYMEX prices but may be adjusted to reflect current knowledge of gas pricing trends. It is recognized that the natural gas futures prices traded daily in the commodity market fluctuate widely in response to technical analyses by traders, daily business news and the weather. Nonetheless, the NYMEX price represents the price that industry participants are willing to offer for gas at a given point in time.

In addition to the projected cost of gas, Columbia incorporates demand and commodity transportation costs of all pipelines operating in its service territory.

Columbia's goal in estimating prices is to project, as accurately as possible, the cost of supply to the Company at the city gate. The PLEXOS model utilizes the monthly estimate of gas prices and transportation fuel and commodity costs to develop city gate rates and a least cost plan for purchasing gas supplies.

Q. Earlier you mentioned the monthly planning process. Can you please elaborate?

A. The monthly planning process is utilized to determine how Columbia should manage its gas supply activity each month to minimize gas costs for its customers while maintaining system reliability. On a monthly basis, Columbia updates its projection of future gas prices over the near term and incorporates additional information, including storage levels and reliability considerations, into the PLEXOS model. Columbia then conducts analyses utilizing the PLEXOS model, incorporating customer demand levels, transportation capacity and gas prices to determine the level of flowing supplies and storage activity that will minimize gas supply costs while maintaining safe, reliable service. The monthly planning analysis helps identify term and spot market purchase requirements, swing gas requirements, capacity release and off-system sales opportunities, and operational targets for storage. Upon completion of the monthly planning analysis, Columbia conducts an internal meeting where the results of the analysis are presented and discussed, and a purchasing strategy is developed for the forthcoming month. The analysis is conducted before the beginning of each month and can be adjusted during the month as conditions dictate.

IV. COLUMBIA'S CHOICE^{SM} PROGRAM

Q. Please describe briefly Columbia's Customer CHOICE^{SM} program.

A. Under the Customer CHOICE^{SM} program, NGSs are required to deliver gas supplies to Columbia at a constant daily quantity each day of the year. Columbia remains the SOLR and provides needed balancing services to match supply and demand for all customers.

Q. Please elaborate on the NGSs' delivery obligations under Columbia's Customer CHOICE^{SM} program.

A. Columbia's Customer CHOICE^{SM} program requires NGSs to deliver to Columbia's city gates, on a firm basis, an equal amount of gas every day of the year to satisfy their customers' annual gas requirements. Each month Columbia determines the normalized annual consumption for each NGS customer aggregation group. This volume is then divided by 365 to yield the volume of natural gas each NGS is required to deliver to Columbia for each of its aggregation groups each day of the month. Customer consumption above or below the normalized annual volumes are reconciled to the NGS's actual deliveries annually.

Q. Please describe the aggregation groups and their purpose.

A. Aggregation groups allow NGSs to aggregate similarly situated customers, located within a given geographical area, for purposes of nominating and scheduling gas supplies to Columbia. Aggregations provide the NGS with the ability to combine customers so that the imbalances between supply and demand for multiple customers are netted together instead of requiring balancing for individual customers. The netting reduces the administrative requirements for both Columbia and the NGS. Aggregation groups also enable Columbia to manage the receipts of natural gas on its system when and where needed to ensure system reliability and therefore, satisfy the requirements of its customers.

Q. Does Columbia anticipate any changes to this process?

A. Not at this time.

Q. May NGSs have more than one aggregation group?

A. Yes, they may. Columbia requires each NGS to have a minimum of one aggregation group for all of its customers located within the geographic boundaries of each TCO specified Market Area. These Market Areas are established by TCO to facilitate the operational needs of its transmission system. Aligning the aggregation groups to these Market Areas is one means of assuring safe and reliable service.

Q. How do NGSs acquire firm capacity to participate in Columbia's Customer CHOICE[SM] program?

A. Columbia's Customer CHOICE[SM] program operates as a mandatory capacity assignment program, with one exception. The program allows NGSs participating in the CHOICE[SM] program the opportunity to provide Other Primary FTS capacity should Columbia have a projected design day capacity deficiency. Each year, Columbia determines if its contracted capacity is sufficient to meet its projected design day demand. In the event it is not, Columbia will provide CHOICE[SM] participating NGSs the opportunity to provide Other Primary FTS capacity that the NGS may utilize to provide supplies for its CHOICE[SM] program customers. To the extent CHOICE[SM] NGSs are able to provide Other Primary FTS, which has primary delivery point entitlements at a Columbia city gate, the NGS will be permitted to utilize that capacity in lieu of mandatory assignment from Columbia of a like volume. The volume of Other Primary FTS that CHOICE^{SM} NGSs may provide under this program is limited to any deficiency that Columbia may project for the forthcoming year. To the extent that an NGS is unable to provide Other Primary FTS that is acceptable to Columbia, the NGS must take mandatory assignment of FTS capacity from Columbia. Because Columbia does not currently have a projected design day capacity deficiency, NGSs are not permitted to provide Other Primary FTS capacity.

Q. Who is responsible for the payment of demand costs when the capacity is assigned to the NGS by Columbia?

A. As with other capacity release transactions, the assignee or the NGS has the responsibility to pay the pipelines directly for the assigned capacity. However, Columbia remains ultimately liable for charges in the event of non-payment of released capacity costs by the assignee.

Q. Does Columbia retain any capacity to provide service to the CHOICE^{SM} Program customers?

A. Yes, Columbia retains firm contract rights to all storage, other upstream pipeline and peaking capacity, if any.

Q. Who pays for the costs of this retained capacity?

A. The customers participating in the Customer CHOICE^{SM} Program pay the costs of this retained capacity. Columbia charges the participating customers a rate per unit of throughput to recover the costs Columbia incurs. This rate is equal to the Purchased Gas Demand Cost (“PGDC”) charge in Columbia’s sales tariff less the costs of assigned EGTS and TCO capacity, adjusted for storage injection and withdrawal charges. This calculation assures that sales and CHOICE^{SM} customers are paying the same amount for capacity.

Q. Please describe Columbia's obligations as a SOLR.

A. In general, the SOLR retains the responsibility to maintain safe and reliable service and ensure that adequate supplies are available to satisfy daily, seasonal and annual requirements for residential, small commercial, small industrial, other essential human needs customers and any other customer class determined by the Commission to fall within the SOLR function. Included in the SOLR function are sales to customers that have not chosen an alternate supplier, choose to be served by the SOLR, or are refused service by NGSs. The SOLR also provides supplies for customers whose NGS fails to deliver their requirements.

Q. Please describe how Columbia, as SOLR, maintains safe and reliable service.

A. Consistent with its role as a public utility, Columbia maintains safe and reliable service by providing those services it is uniquely qualified to provide and manage. These include:

1) management of distribution mains and services from the city gate to the customer meter;
2) determination of customer requirements;
3) management of city gate requirements; and

4) assuring that adequate capacity is available in the long-term to satisfy the requirements of its residential customers and the human need requirements of its small commercial and industrial customers even under extreme (design) conditions.

Item (4) is closely aligned with Columbia's long-range planning efforts in assuring that adequate supplies and capacity are available to human needs customers as well as those other customers that contract for firm services from Columbia.

Q. Please describe Columbia's SOLR function as it pertains to distribution mains and services.

A. Columbia's SOLR responsibilities in this area include: (a) field management of maintenance, customer service, regulation and measurement; (b) gas control operations; (c) management of any on-system storage, peaking or other supply related assets; and (d) determination of maximum daily delivery obligations ("MDDO") and pressure requirements at each point of delivery ("POD") with interstate pipelines.

Q. What SOLR responsibilities are incorporated in the determination of customer requirements?

A. SOLR responsibilities in this area include calculation of annual customer requirements and associated daily NGS deliveries, establishment of design day criteria and determination of firm and non-firm design day requirements.

Q. What are Columbia's SOLR obligations related to the management of city gate requirements?

A. The responsibilities related to management of city gate requirements include: (a) provision of no-notice city gate balancing to accommodate differences between supplier deliveries and customer demand, including GDS customers; (b) management of the annual true-up process; (c) evaluation of NGS requests for utilization of alternate delivery points; (d) maintenance of a no-notice back-up supply in the event of an NGS failure; (e) development and administration of a plan for dealing with an NGS failure; (f) development and maintenance of effective on-system nominations systems; and (g) development and enforcement of supply reliability requirements, including implementation of OFO/OMOs and other system management tools provided for in the tariff.

Q. What SOLR responsibilities are included in assuring that long-term capacities are available for human needs customers?

A. Reliability of service to human needs customers requires that access to firm capacity be without question. In today's energy environment, that assurance is only accomplished through the maintenance of long-term capacity assets that do not disappear because of an election of a supplier to exit the business, bankruptcy or more favorable economic options serving other segments of the natural gas marketplace. These human needs customers do not have a choice in the utilization of natural gas. They need it for the essential life sustaining uses of heating their homes and cooking their meals. The maintenance of firm capacity on an unquestioned basis is essential in assuring reliable service. This long-range process ensures that adequate pipeline capacity is available to satisfy customer requirements and that adequate contractual commitments exist at each POD to satisfy MDDO and pressure obligations. Also, active participation in FERC activities is a key part of the process.

Q. What gas supply and capacity resources does Columbia utilize to provide these SOLR functions?

A. Columbia will continue to utilize those assets presently under its control that are not assigned to NGSs under its Customer CHOICE^{SM} program. Included are capacity assets Columbia will require to maintain balancing services and/or system integrity for service to its customers. These are principally storage and storage-related transportation capacities. Additionally, all capacity assignments made to NGSs participating in Columbia's Customer CHOICE^{SM} program will be made on a recallable basis. If an NGS who has been assigned capacity fails to deliver supplies to Columbia in a manner consistent with Columbia's tariff, Columbia will recall this capacity, as needed, to maintain service to affected customers. While it is possible that Columbia may experience a delay in recalling capacity assigned to an NGS and filling that capacity with back up supplies, Columbia will be able to continue to provide adequate supplies to its customers from its retained storage on all but extremely cold days. Columbia's tariff also requires that any NGS that provides capacity under Columbia's Acquisition Process for New and Renewed Contracts and later leaves the Customer CHOICE^{SM} program must provide for that capacity to be assignable to Columbia until such time as Columbia is able to acquire equivalent replacement capacity.

Q. Has Columbia made any exchange, capacity release or off-system sales transactions with affiliates?

A. Columbia had two sales transactions with its affiliate Columbia Gas of Ohio.

Q. Were these activities identified in your Exhibit 5?

A. Yes, the sales transactions were identified in Exhibit 5.

V. COLUMBIA'S ACTIVITIES AT FERC

Q. Was Columbia active in any FERC proceedings during the last year?

A. Yes, as shown in Company Exhibit No. 3, either directly, as part of the Columbia Distribution Companies, or through its memberships in industry trade associations like the American Gas Association ("AGA"), Columbia was active at FERC in regulatory proceedings, rulemakings and policy formulation that had the potential to impact services and/or costs to Columbia and its customers.

Q. Generally, how has Columbia represented the interests of its customers by participating in each of the listed proceedings?

A. First, Columbia reviews all relevant FERC notices of rate, certificate and rulemaking proceedings through a monitoring network on FERC's website and through AGA's notifications. Further, Columbia, as a customer of various pipelines, receives notices of rate and proposed tariff changes as filed. Finally, Columbia makes every effort to conduct various forms of informal communication with its pipeline suppliers, peer customers of those pipelines and respective interested state agencies to keep apprised of upcoming proposals, expected tariff filings, and any other federally regulated activities.

Second, a preliminary analysis of notices and filings is completed by Columbia's Energy Supply and Optimization ("ES&O") personnel for discussion with Legal and Regulatory personnel. Based on those discussions, a determination is made about whether to intervene. If a determination is made to intervene, then intervention points are developed. A decision to become an active participant in a proceeding protects Columbia's right to address the elements of a filing that are significant to Columbia. Being an active participant ensures that Columbia is advised of all pre-hearing, technical and settlement conferences and hearings convened in a case, as well as the comments and interventions of other parties.

Analyses of those filings in which Columbia has intervened is conducted on an ongoing basis. The potential impact of rate and policy changes is determined. From these analyses, Columbia reasonably formulates positions that best represent the interests of Columbia and its customers, and recommends a level of involvement that is necessary to advocate those positions. Columbia pursues those positions through the legal process, by filing comments and/or testimony on its own when appropriate, through trade or customer groups, through participation in technical conferences and/or through negotiations within the settlement process.

As indicated earlier, Columbia is also a member of the AGA, a natural gas industry trade group that participates actively in select proceedings on behalf of its local distribution company members.

As demonstrated by Company Exhibit No. 3, Columbia was an active party to numerous FERC proceedings in calendar year 2023. Columbia has been similarly active in the first quarter of 2024. Many more pipeline filings and proposals that Columbia reviewed during that time are also listed, but Columbia only became a party in those cases where it determined that there was the potential for impact on it or its customers.

Q. Please summarize Columbia's FERC activities throughout the past year.

A. During 2023, Columbia paid particular attention to the impact of rate filings by pipelines that proposed adjustments to tariff rates. Columbia's activities can be summarized as follows:

1) reviewing all FERC filings by all pipelines that provide natural gas transportation services to Columbia;
2) intervening in and following all FERC dockets having potential ramifications to Columbia;
3) participating in all major proceedings in which tariff changes and/or reliability issues affecting Columbia's customers were scheduled to be discussed (this included attending technical conferences and settlement conferences hosted by the FERC and the pipelines); and
4) In July 2023, National Fuel filed a Section 4 rate case at FERC. The Company filed an intervention on July 14, 2023. FERC issued an order accepting and suspending tariff records, subject to refund and establishing hearing procedures, on August 31, 2023. Hearings are ongoing, and no

settlement has been issued to date.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc
Firm Peak Day and Annual Entitlements
Contract Year 2024-25

	Peak Day Entitlements		Annual Entitlements [1]	
Supply Source	Daily (MDth/Day)	Percentage (%)	Annual (MDth/Yr)	Percentage (%)
Storage				
TCO FSS	395.7	59%	21,481	21%
EGTS GSS[2]	28.8	4%	1,844	2%
Equitrans 115SS[3]	19.1	3%	0	0%
National Fuel	2.4	0%	265	0%
Total Storage	446.1	67%	23,325	23%
Firm Transportation (City Gate)				
TCO	129.7	20%	47,346	46%
Eastern Gas Transmission	5.3	1%	1,918	2%
Tennessee Gas Pipeline	19.3	3%	7,043	7%
Texas Eastern Transmission	22.5	3%	8,195	8%
Equitrans	35.9	5%	13,093	13%
National Fuel FTS	5.8	1%	2,123	2%
Total City Gate FTS	218.4	33%	79,718	77%
Local Production				
Direct into CPA	0.7	0%	256	0%
TOTAL CITY GATE SUPPLY	665.2	100%	103,299	100%
Firm Transportation (Upstream)				
Tennessee	4.3	--	--	--
Texas Eastern	3.1	--	--	--
Total	7.4	--	--	--

[1] Includes seasonal storage entitlements. Equitrans seasonal entitlements of 2,000,000 Dth and Eastern Gas Transmission seasonal entitlements of 240,000 Dth are dedicated to Enhanced Balancing Service (EBS) Option 1 provided to General Distribution Service (GDS) customers, and are excluded from this Exhibit.

[2] For contract year 2024-25, 3,152 Dth of the winter season firm transportation capacity will be charged to and utilized in the provision of EBS Option 1.

[3] For contract year 2024-2, 9,422 Dth of the winter season firm transportation capacity will be charged to and utilized in the provision of EBS Option 1.

Columbia Gas of Pennsylvania, Inc
Firm Peak Day Supplies vs Firm Demand
(MDth/Day)

Contract Year	2024/25	2025/26	2026/27	2027/28
Supply Source				
Storage				
TCO FSS	395.7	395.7	395.7	395.7
EGTS GSS[1]	28.8	28.8	28.8	28.8
EGTS GSS[1] Max Hour adjustment	5.2	5.2	5.2	5.2
Equitrans 115SS	19.1	19.1	19.1	19.1
National Fuel	2.4	2.4	2.4	2.4
Total Storage	451.2	451.2	451.2	451.2
Firm Transportation (City Gate)				
TCO	129.7	129.7	130.5	129.7
Eastern Gas Transmission[1]	5.3	5.3	5.3	5.3
Tennessee Gas Pipeline	19.3	19.3	19.3	19.3
Texas Eastern Transmission	22.5	22.5	22.5	22.5
Texas Eastern Transmission A2M3 Precedent				3.0
Equitrans	35.9	35.9	35.9	35.9
National Fuel FTS	5.8	5.8	5.8	5.8
Total City Gate FTS	218.4	218.4	219.2	221.4
Local Production				
Direct into CPA	0.7	0.7	0.7	0.7
TOTAL CITY GATE SUPPLY	670.3	670.3	671.2	673.3
Less Capacity to provide Standby	5.1	5.1	5.1	5.1
Less Capacity to provide EBS	12.6	12.6	12.6	12.6
Net Capacity	652.6	652.6	653.5	655.6
2023 DDF FIRM REQUIREMENT	627.6	629.0	631.6	634.4
Max Hour Adjustment	9.8	9.8	9.8	9.9
Adjusted 2022 DDF Firm Requirement	637.4	638.8	641.4	644.3
DIFFERENCE	15.2	13.8	12.1	11.3
% OF DEMAND	2.4%	2.2%	1.9%	1.8%
2023 DDF FIRM REQUIREMENT plus 3%	646.7	648.2	650.8	653.7
DIFFERENCE	5.9	4.4	2.7	1.9
% OF DEMAND	0.9%	0.7%	0.4%	0.3%

[1] Eastern Gas Transmission (EGTS) formerly Dominion Transmission (DTI)

COLUMBIA STATEMENT NO. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2024-3047014
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF

JESSICA FISCHER

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2024

Q. Please state your name and business address.

A. My name is Jessica Fischer and my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC") as Lead Regulatory Analyst - Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company").

Q. What are your responsibilities as Lead Regulatory Analyst - Columbia Gas of Pennsylvania, Inc.?

A. I am responsible for the preparation and support of regulatory filings for Columbia, with duties including purchased gas cost filings and other recovery mechanisms. I am also responsible for the implementation of Columbia's rates into the Company's billing system.

Q. What is your educational and professional background?

A. I graduated from The Ohio State University in 2010 with a Bachelor's of Science in Business Administration with a specialization in Accounting. In 2010, I was hired as staff auditor for Ary Roepcke Mulchaey, a public accounting firm headquartered in Columbus, Ohio, where I primarily audited defined contribution and defined benefit plans in a variety of industries including, real estate, healthcare, and retail. I started with NCSC in 2013 as a Financial Analyst for Columbia Gas of Massachusetts performing a variety of accounting functions including monthly closing. In 2015, I transitioned to my current role for Columbia.

Q. Have you previously testified in proceedings before this or any other Commission?

A. Yes, I have testified before this Commission in Columbia's 2022 1307(f) proceeding, at Docket No. R-2022-3031172 and Columbia's 2023 1307(f) proceeding at Docket No. R-2023-3038630.

Q. Please describe the scope of your testimony in this proceeding.

A. I am responsible for the overall presentation of Exhibit Nos. 1-A through 1-F, which were submitted in response to the Commission's requirements in 52 Pa. Code § 53.64, *et seq*. I am also sponsoring Columbia Exhibit JF-1, which computes Columbia's retainage rate for transportation customers. In addition, I am sponsoring Columbia Exhibit JF-2 and Columbia Exhibit JF-3, that present an alternative calculation of Columbia's quarterly PGC rate for informational purposes, pursuant to the terms of the settlement of Columbia's 2023 1307(f) proceeding.

Q. Were the exhibits that you are sponsoring prepared by you or by persons working under your direction?

A. Yes, they were.

Q. Is the information contained within the exhibits that you are sponsoring true and correct to the best of your knowledge and belief?

A. Yes, it is.

Q. What are the total projected changes in sales service rates to become effective October 1, 2024, for recovery of purchased gas costs?

A. Referring to Exhibit No. 1–A, Schedule 1, Sheet 1 of 2, Columbia has projected an overall increase of $0.01968 per therm to its PGC rate for customers served under Rate RSS – Residential Sales Service, Rate SGSS – Small General Sales Service, and Rate LGSS – Large General Sales Service, as compared to rates then currently in effect as of February 28, 2024. I note that this rate will likely be revised in the future, based upon updates to the filing.

Q. What are the principal reasons for this projected change in the overall PGC rate?

A. The change is driven primarily by an increase in the projected gas costs for the application period resulting in an increase of $0.01819 per therm. The secondary driver is the change in the E-factor to recover prior period under/over collections. During the current 1307(f) reconciliation period customers are being charged $0.00722 per therm through the E-factor. The projections for the Application Period show that the Company will be in an under collected position, and therefore, the E-factor rate is projected to be $0.00121 per therm, for an overall increase of $0.00149 per therm. The increase to the projected gas costs and E-factor result in an overall increase of $0.01968. These changes are detailed on Exhibit No. 1-A, Schedule 1, Sheet 1 of 2.

Q. Please describe the Company's calculation of retainage.

A. In accordance with the Commission's orders in prior PGC proceedings (Docket Nos. R-2009-2093219 and R-2010-2161920), Columbia has calculated retainage based on a three-year rolling average, with an August 31st ending date for each year, which excludes Mainline Class I customer quantities and includes Company use in the calculation. Exhibit JF-1 to my testimony calculates the retainage rate to be effective January 1, 2025, resulting from the three-year average ending August 31, 2023. The retainage rate will be 1.2%.

Q. Please describe Exhibit No. 1-A, Schedule 1, Sheet 2.

A. This sheet demonstrates the calculation of the Daily Purchased Gas Demand Rate under Rate SS. This calculation is based on the total estimated demand charges for the projected period October 2024 through September 2025, divided by Columbia's total demand billing determinants for the same period.

Q. Please describe Exhibit No. 1-A, Schedule 2.

A. Exhibit No. 1-A, Schedule 2, Sheets 1 through 4 detail the calculation of the over/under-collection for the period of October 2024 through September 2025. This schedule shows that the rates contained in Exhibit No. 1-A would recover the projected gas costs included in Columbia's filing based upon projected quantities. Any balance at the end of the period is due to rounding.

Q. Please describe Exhibit No. 1-A, Schedule 3.

A. Exhibit No. 1-A, Schedule 3 details the calculation of the purchased gas demand charge that is paid by customers selecting Columbia's CHOICE℠ service. Columbia's CHOICE℠ service offers residential customers and commercial customers an opportunity to purchase their natural gas supply service from a licensed Natural Gas Supplier ("NGS") under Rates Residential Distribution Service ("RDS") and Small Commercial Distribution ("SCD"). Under CHOICE℠

service, NGSs are assigned, and pay for, a portion of Columbia's pipeline capacity. The NGS must deliver an amount of gas every day of the year that is equal to 1/365th of the NGS customer group's annual normalized consumption. Under the CHOICE℠ program, Columbia manages daily imbalances with retained capacity and storage. Those customers who select an NGS are subject to the purchased gas demand component of Columbia's purchased gas cost rate, net of a credit to reflect the cost of Columbia Gas Transmission, LLC ("Columbia Transmission") and Eastern Gas Transmission and Storage, Inc. ("EGTS") pipeline capacity assignable to their NGS. The credit for the upcoming PGC period is $0.02823/therm.

Q. Please describe Exhibit No. 1-B.

A. Exhibit No. 1-B is submitted in response to the Commission's filing requirement at 52 Pa. Code § 53.64(c)(1) and details the monthly projected purchases from the Company's various gas suppliers for the period October 2024 through September 2025. Exhibit No. 1-B consists of ten schedules that detail and summarize the estimated purchased gas demand costs from Columbia Transmission, Texas Eastern Transmission Corp ("TETCO"), EGTS, Tennessee Gas Pipeline Co. ("Tennessee"), National Fuel Gas ("National Fuel"), and Equitrans, and projected commodity purchases from various interstate suppliers, storage, and Pennsylvania local producers.

The monthly projected purchases included in Exhibit No. 1-B, Schedule 1, Sheet 1 of 4, are the twelve-month summary of the estimated demand and commodity costs of gas. As indicated on line 5 of Schedule 1, Sheet 1, the total projected cost of gas for the twelve-month period is $ 184,351,645.

Exhibit No. 1-B, Schedule 1, Sheet 2 of 4 summarizes the projected demand cost from Exhibit No. 1-B, Schedules 2 through 7 for the October 2024 through September 2025 period, by month and by pipeline. Schedule 1, Sheet 2 includes a fixed annual credit of $300,000 related to the provision of elective balancing services ("EBS") approved by the Commission in the settlement at Docket No. R-00016668. Schedule 1, Sheet 3 summarizes the projected commodity costs from Schedules 8 through 10 by month and by source. Schedule 1, Sheet 4 is a summary of the projected commodity quantities, in Dth, by month and by source. The demand and commodity costs have been brought forward to Exhibit No. 1-A to be used in the computation of rates.

Q. Please continue with your explanation of the other schedules contained in Exhibit No. 1-B.

A. Exhibit No. 1-B, Schedules 2 through 7 detail the projected demand cost reflected on Schedule 1, Sheet 2. The projection of the demand costs for each pipeline is based on the projected monthly capacity and the projected demand rates.

Table 1 below summarizes the pipelines and the projected demand cost related to each:

Table 1 Projected Pipeline Demand Costs from Exhibit No. 1-B		
Columbia Gas Transmission, LLC	Schedule 2	$ 78,538,134
Texas Eastern Transmission Corporation	Schedule 3	$ 3,636,820
Eastern Gas Transmission and Storage	Schedule 4	$ 3,264,385
Tennessee Gas Pipeline	Schedule 5	$ 1,338,564
National Fuel Gas Supply Corporation	Schedule 6	$ 1,170,840
Equitrans	Schedule 7	$ 2,766,426

Company witness Monnig will provide additional detail regarding capacity contract changes.

Q. Please explain the development of the projected commodity cost reflected in Exhibit No. 1-B.

A. The projected commodity cost shown on Exhibit No. 1-B, Schedule 1, Sheet 3 is detailed in Schedules 8 through 10 of Exhibit No. 1-B. The detail of the projected commodity cost is by month and by source.

Schedule 8 details the projected purchases of gas under term contracts. Columbia will be utilizing transportation capacity on several pipelines and in different combinations for its term contracts. The purchase price for this gas reflects the commodity cost of the gas delivered to the city gate. The product of the projected purchases times the projected city gate purchase rates amounts to $17,134,836. As of October 1, 2021, Columbia's Customer Assistance Program ("CAP") customers are being served by Columbia sales service until a new supplier submits a successful bid to provide CAP gas supply. Therefore, no separate CAP purchases or CAP billings are shown on Schedule 8.

Schedule 9 details the projected purchases of spot gas (Line 9 - $90,665,762) and local gas (Line 15 - $648,336). The total projected cost of these purchases is $91,314,098. In her testimony, Ms. Monnig discusses the projection of prices used in the development of city gate prices on Schedules 8 and 9.

Schedule 10 is a listing of the projected monthly gas commodity storage costs. Columbia will use storage from EGTS, Equitrans, Columbia Transmission, and National Fuel. The total net cost of gas from storage is projected to be ($14,512,158). This amount includes the injection/withdrawal charges and the transportation commodity costs. Monthly injections are priced at the average commodity cost of gas purchased for the month. Monthly withdrawals of gas from storage are based on the average cost of gas in storage for the month.

Q. Please continue your testimony by describing Exhibit No. 1-C.

A. Exhibit No. 1-C is submitted in accordance with § 53.64(c)(1) of the Commission's regulations and sets forth the total estimated purchased gas costs from all gas supply sources for the period February 2024 through September 2024. Exhibit No. 1-C consists of ten schedules detailing the projected transportation and storage capacity cost of purchases from Columbia Transmission, TETCO, EGTS, Tennessee, National Fuel, and Equitrans, and projected commodity purchases from interstate suppliers, storage, and Pennsylvania local producers. Ms. Monnig provided the monthly purchase quantities.

Q. Please describe the schedules included in Exhibit No. 1-C.

A. Exhibit No. 1-C, Schedule 1, Sheet 1 sets forth the summary of the total estimated purchased gas costs, by month, for the period February 2024 through September 2024. Schedule 1, Sheet 2 summarizes the total estimated purchased gas demand costs by month and pipeline for the period February 2024 through September 2024.

Exhibit No. 1-C, Schedule 1, Sheet 3 summarizes the total estimated purchased gas commodity costs, by month and by source, which are further detailed on Schedules 8 through 10.

Exhibit No. 1-C, Schedule 1, Sheet 4 is a summary of the total estimated purchased gas commodity quantities, in Dth, by month and by source.

Q. Please explain the projected demand cost development.

A. Exhibit No. 1-C, Schedules 2 through 7 detail the projected demand costs reflected on Schedule 1, Sheet 2, by pipeline company. The projection of the demand costs for each pipeline company is based on the projected monthly capacity and the projected demand rates. Table 2 below summarizes those pipelines and the projected demand cost related to each:

Table 2

Projected Pipeline Demand Costs from Exhibit No. 1-C

Columbia Gas Transmission, LLC	Schedule 2	$48,381,830
Texas Eastern Transmission Corporation	Schedule 3	$2,477,660
Eastern Gas Transmission and Storage	Schedule 4	$2,120,730
Tennessee Gas Pipeline	Schedule 5	$924,215
National Fuel Gas Supply Corporation	Schedule 6	$780,560
Equitrans	Schedule 7	$1,511,636

Q. Please explain the projected commodity cost development.

A. The projected commodity cost shown on Exhibit No. 1-C, Schedule 1, Sheet 3 is detailed in Schedules 8 through 10. The detail of the projected commodity cost is by month and by source.

Schedule 8 details the total estimated purchased gas commodity costs under term contracts. Columbia will be using transportation capacity on several pipelines and in different combinations. The purchase price for this gas reflects the commodity cost of the gas delivered to the city gate. The product of the projected purchases times the projected city gate purchase rates equals $4,011,567 of projected purchased gas commodity cost. As explained previously, no CAP purchases or CAP billings are reflected in this projection.

Schedule 9 provides details, for each month in the February to September 2023 period, of the total estimated purchased gas commodity costs associated with spot and local gas purchases. The projected cost of these purchases is $41,755,853 (Line 9 – $41,475,662 + Line 15 – $280,191). In her testimony, Ms. Monnig discusses the projection of prices used in the development of city gate prices on Schedules 8 and 9.

Schedule 10 shows the total estimated purchased gas commodity costs associated with storage. Columbia will use storage from EGTS, Equitrans, Columbia Transmission and National Fuel to provide service to customers. The total cost of gas from storage for the eight-month period February 2024 through September 2024 is projected to be ($3,926,468), which includes the injection/withdrawal charges and the transportation commodity cost. The monthly injection and withdrawal rates were developed utilizing the methodology discussed in relation to Exhibit No. 1-B, Schedule 10 (Page 8 of this testimony).

Q. Please describe the calculations contained in Exhibit No. 1-D.

A. Exhibit No. 1-D complies with § 53.64(c)(1) of the Commission's regulations. Exhibit No. 1-D Schedule 1 sets forth the historic cost of gas by type and month for the February 2023 through January 2024 period. Section 53.64(c)(1) requires Columbia to file a complete listing of the sources of gas supply used in the prior twelve months that ends two months prior to the date of the Company's tariff filing. Exhibit No. 1-D consists of six schedules detailing the historic cost of gas purchased from interstate sources through transportation arrangements with interstate pipelines, Pennsylvania local producers and underground storage. Exhibit No. 1-D, Schedule 1, Sheet 1 summarizes the total costs associated with the purchases. Exhibit No. 1-D, Schedule 1, Sheet 2 itemizes the demand and commodity costs shown on Exhibit No. 1-D, Schedule 1. Exhibit No. 1-D, Schedule 1, Sheet 3 details the volumes associated with the purchases. Exhibit No. 1-D, Schedules 2 through 6 provide additional detail on the purchases by type and month. Ms. Monnig will support Exhibit Nos. 1-D-1 through 1-D-3.

Q. Please describe Exhibit No. 1-E.

A. Exhibit No. 1-E, which consists of five schedules, sets forth the calculations supporting the experienced net over/under-collection level used in the rate recovery calculation.

Q. Please describe Exhibit No. 1-E, Schedule 1.

A. Exhibit No. 1-E, Schedule 1 shows a summary of all components used in the calculation of the over/under-collection portion of the PGC rate scheduled to become effective October 1, 2023. Schedule 1, Line 11 reflects a projected total experienced net under-collection of $4,006,445. This under-collection amount includes: anticipated over/under-collection during the 2023 § 1307(f) Application Period (October 2023 through September 2024); reconciliation of prior period proceeds received for off-system sales and capacity releases; and reconciliation of prior period over/under-collections.

Q. Please explain the calculations on Exhibit No. 1-E, Schedules 2a and 2b.

A. Schedules 2a and 2b set forth the reconciliation of prior period commodity and demand costs from the 2023 PGC period of ($1,020,387) and ($239,818) to be collected.

Line 19 of Schedule 2a reflects the estimated prior period commodity under-collection of $1,020,387 that Columbia anticipates it will experience for the twelve months ending September 2024. This estimated prior period commodity under-collection is calculated by adding: 1) the over-collected commodity balance as of September 2023 (Line 1), 2) a beginning balance adjustment (Line 2) of $132,885, and 3) the sum of the actual and projected refunds and recoveries for the period October 2023 through September 2024 (Line 18).

Line 19 of Schedule 2b reflects the estimated prior period demand under-collection of $239,818 that Columbia anticipates it will experience for the twelve months ending September 2024. This estimated prior period demand under-collection is calculated by adding: 1) the under-collected demand balance as of

September 30, 2023 (Line 1), 2) a beginning balance adjustment of ($45,680), and 3) the sum of the actual and projected refunds and recoveries for the period October 2023 through September 2024 (Line 18).

Q. Please explain the beginning balance adjustments on Schedules 2a and 2b.

A. The beginning balance adjustment on Schedule 2a of $132,885 represents a commodity interest adjustment for the months of February 2023 through September 2023, increasing the interest rate from 7.50% to 8.50% to reflect the prime interest rate as of January 31, 2024. The beginning balance adjustment of ($45,680) on Schedule 2b represents a demand interest adjustment for the months February 2023 through September 2023, increasing the interest rate from 7.50% to 8.50% to reflect the prime interest rate as of January 31, 2024.

Q. Please explain the calculations on Schedule 3.

A. Schedule 3 reflects the calculation of the estimated net - under-refunded Unified Sharing Mechanism ("USM") proceeds of $55,958, as shown on Exhibit No. 1-E, Schedule 1, line 4. The purpose of this calculation is to estimate the portion of the USM proceeds that will be collected during the current PGC period.

Q. How was the estimated net under-refunded amount of $55,958 for USM proceeds determined?

A. As indicated on Exhibit No. 1-E, Schedule 3, Columbia has included in the E-factor a projected total credit of $2,120,159 for the USM. This is the current estimate of the customers' share of off-system sales and capacity release net proceeds for the twelve months ended September 30, 2024. This amount is allocated 100% to the

PGDC (Schedule 3, Line 16). Currently, Columbia projects to pass back $2,064,201 in USM credits, based upon actual and projected volumes subject to the credit. The result is an under-refund of $55,958.

Q. Will you please continue with your explanation of Exhibit No. 1-E, Schedule 4?

A. Schedule 4 reflects the statement of over/under-collections expected from the application of Columbia's PGC rates for the period October 2023 through September 2024. The monthly over/under-collection amounts for the period October 2023 through January 2024 are based on actual data. The monthly over/under-collection amounts for the period February 2024 through September 2024 are based on projected data. I note that, under the Commission's PGC regulations, the projected amounts will be replaced with actual costs and recoveries through August 2024 as part of Columbia's compliance filing. Exhibit No. 1-E, Schedule 4, Sheet 1a depicts the calculation of the commodity over/(under) collection while Exhibit No. 1-E, Schedule 4, Sheet 1b depicts the calculation of the demand over/(under) collection. The estimated total under-collection of $3,300,625, derived by combining both sheets, is carried forward to Exhibit No. 1-E, Schedule 1, line 6. Likewise, interest associated with the commodity and demand under collections totaling $57,747 is also calculated on Exhibit No. 1-E, Schedule 4, Sheets 1a and 1b respectively, and is carried to Exhibit No. 1-E, Schedule 1, line 8, so that it is included in the E-factor.

Q. How was interest calculated?

A. Interest was calculated at the rate of 8.50% for the months of October 2023 through September 2024 for over/under collections from gas costs. This is the prime rate for commercial borrowing in effect as of January 31, 2024, as reported in The Wall Street Journal, Market Data section under Prime Rate. Columbia applies the prime interest rate for commercial borrowing effective January 31 at the end of the historic reconciliation period, which counsel has advised me is consistent with Act 47's requirement that utilities use the prime rate for commercial borrowing in effect 60 days prior to their annual 1307(f) tariff filing. Columbia will update the interest rate, if necessary, for the February 2024 through September 2024 period in next year's 1307(f) filing, and calculate interest for the months of October 2024 through January 2025 based on the prime interest rate for commercial borrowing for the twelve months ending January 31, 2025.

Q. How is the cost of fuel recovery calculated?

A. The cost of fuel recovery is shown on Exhibit 1-E, Schedule 4, Sheet 1a, Column 3 and Sheet 1b, Column 5. Columbia's purchased gas cost recovery rates applicable to customers receiving service under Rate RSS, Rate SGSS, and Rate LGSS consist of both PGCC and PGDC components. Rate NSS – Negotiated Sales Service customers pay a cost of gas based on the cost of spot purchases scheduled to flow on the first day of the month. Customers receiving service under Rate SGDS Priority One, Rate SCD and RDS pay only the PGDC rate for volumes transported. Exhibit No. 1-E, Schedule 4, Sheet 2a, column 2 shows the PGCC rate that is applied to all sales under Rate RSS, Rate SGSS and Rate LGSS. Exhibit No. 1-E, Schedule 4, Sheet 3, column 3 shows the recovery of gas costs from NSS customers.

Q. Please explain the calculation of the total demand revenue included in Exhibit No. 1-E, Schedule 4, Sheet 1b, column 5 that was used to calculate the over/under-collection included in the pre-filing information.

A. Exhibit No. 1-E, Schedule 4, Sheet 1b, column 5 summarizes the total purchased gas demand revenue collected from customers. The details of the purchased gas demand revenue are shown on Sheets 4a through 6. Estimated total purchased gas demand revenue recovery is $ 85,932,239.

Q. Please explain the calculation of the EBS Option 2 revenue in Exhibit No. 1-E, Schedule 4, Sheet 1b, column 2 that was used to calculate the over/under-collection.

A. Exhibit No. 1-E, Schedule 4, Sheet 1b, column 2 summarizes Rider EBS Option 2-revenues collected from one NSS customer. Currently, no General Distribution Service customers have elected Option 2. The detailed calculation of the revenue is shown on Exhibit No. 1-E, Schedule 4, Sheet 6. Estimated total balancing revenue for the period October 2023 through September 2024 is $610.

Q. Please explain the calculation of Capacity Release Revenue under Rate NSS as contained on Schedule 4, Sheet 1b, column 4.

A. The calculation of the Capacity Release revenues from Rate Schedule NSS is detailed on Exhibit No. 1-E, Schedule 4, Sheet 6. Estimated total revenue from NSS Capacity Release for the period October 2023 through September 2024 is $2,286.

Q. Columbia's tariff contains several special provisions for Rate NSS. One provision is that any customer served under rate NSS with an annual throughput requirement below 64,400 therms be reported through the 1307(f) process. Does Columbia have any such customers?

A. No. The one NSS customer identified above has an annual throughput that is greater than 64,400 therms.

Q. What is calculated in Exhibit No. 1-E, Schedule 5?

A. Schedule 5 presents the demand penalty credits and supplier refunds received from suppliers during the October 2023 through September 2024 period to be passed back beginning October 1, 2024. Witness Paloney will discuss the distribution of penalty credits and supplier refunds further in her direct testimony, Columbia Statement No. 3.

Q. Please describe Exhibit No. 1-F, Schedule 1.

A. Schedule 1 of Exhibit No. 1-F constitutes Columbia's statement of over/under-collections during the twelve months ended January 31, 2024. This schedule, which is submitted in compliance with § 53.64(i)(1)(i)-(iv) of the Commission's regulations, reflects an under-collection of $5,994,826 as detailed on Schedule 1, Sheet 1. Exhibit No. 1-F, Schedule 1, Sheets 1a and 1b respectively depict the calculations for the commodity over/under collection, the demand over/under collection, the commodity over/under collection with an itemization for Rate Schedule NSS, and the demand over/under collection with an itemization for Rates SS and NSS. Exhibit No. 1-F, Schedule 1, Sheet 2a, reconciles the differences between the Company's total purchased gas costs, as reflected on Exhibit No. 1-D and the Company's financial statements, with the cost of fuel shown for PGC purposes which appears on Exhibit No. 1-F, Schedule 1, Sheet 1. Exhibit No. 1-F, Schedule 1, Sheet 2b reconciles the gas commodity purchases reflected in Exhibit 1-D and the commodity cost of fuel for PGC purposes shown on Exhibit 1-F, Schedule 1, Sheet 1a, as agreed to in the Settlement of the 1307(f) proceeding at Docket No. R-2012-2293303.

Q. Did natural gas costs exceed revenues collected by more than 10% in the previous 12-month period due to customers switching from sales service to transportation service as described in Act 47?

A. No, Exhibit 1-F, Schedule 1, Sheet 1 shows the Company in an under-collected position for the historical 12-month period ending January 2023 of 2.76%.

Q. Please explain Exhibit No. 1-F, Schedule 2.

A. Exhibit No. 1-F, Schedule 2, attached to my testimony, complies with § 53.64(i)(1)(iv) and (v) of the Commission's regulations. This schedule details the difference between actual costs for the period February 2023 through January 2024, and projected costs included in the gas cost recovery components established in the 2022 1307(f) proceeding for the period February 2023 through September 2023, and in the 2023 1307(f) proceeding for the period October 2023 through January 2024.

Q. Please provide the basis for how the customer's portion of USM revenues are projected.

A. Per the 2019 1307(f) Settlement approved by the Commission at Docket No. R-2019-3008255, the USM projection of the customers' share is calculated using a two-year PGC period average, with one year being the most recently completed PGC period available at the time the PGC pre-filing is submitted and the second year being the projected customer share of USM net margin for the current PGC filing year at the time the pre-filing is submitted.

Q. Please provide the calculation utilized to develop USM rate in the prefiling that utilizes the two-year average described above.

A. Please see the calculation below. This rate is shown on Exhibit 1-A, Schedule 1, line 22.

2024 1307(f) Application Filing
PGC Period October 1, 2024 - September 30,2025

PGC Period		USM- Customer Portion	
Oct 22-Sept 23 PGC Period (Actual)	$	(3,351,628)	
Oct 23-Sept 24 PGC Period (Estimate)	$	(2,120,159)	
2 Year Average	$	(2,735,894)	
Projected Demand Sales October 1, 2024 - September 30, 2025		469,941,653	Therms
Off Systems Sales and Capacity Release Credit	$	(0.00582)	per Therm

Q. What commitment did Columbia make in the settlement of its 2023 1307(f) proceeding regarding the calculation of its quarterly gas supply charge?

A. The 2023 1307(f) settlement (R-2023-3038630) contained the following commitment:

Columbia agrees to separately calculate its quarterly gas supply charge component of its PGC in the manner identified in OCA St. No. 1 at pages 6-8, for informational purposes only, and to submit its calculations and resulting rates in its 2024 PGC filing.

Q. What is Columbia's understanding of the calculation identified in OCA St. No. 1 at pages 6-8 in the 2023 1307(f) proceeding?

A. Columbia's understanding of the calculation identified in OCA St. No. 1 at pages 6-8 is calculating the gas supply charge using only projected commodity costs for that quarter. Since this calculation is for a rate effective October 1, 2024, Columbia calculated a rate using projected commodity costs for October 2024 through December 2024.

Q. Please provide a separate calculation of the quarterly gas supply charge using only the projected commodity costs for the period, for informational purposes only.

A. Exhibits JF-2 and JF-3, attached to my testimony, provide a calculation of the quarterly gas supply charge using only the projected commodity costs for the period. The average cost of gas for October 2024 through December 2024 of $0.20480 per therm is shown on Exhibit JF-2, Schedule 1, Sheet 1, Line 5. The calculation for the average cost of gas for the period is shown on Exhibit JF-3, Schedule 1, Sheet 5.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania Exhibit JF-1

	YE Aug-31	2021 Dth	2022 Dth	2023 Dth	3-Year Averages 2021 - 2023	
	Supply					
1	Raw Supply Numbers	78,985,222	81,533,973	78,067,318	79,528,838	
2	Supply Adjustment	25,720	15,825	704	14,083	
3	Cumulative Adj. Supply - Including Supply Adjustments	79,010,942	81,549,798	78,068,022	79,542,921	
4						
5	ML1 Volumes	2,621,167	2,893,490	2,816,378	2,777,012	
6	Cumulative Adj. Supply Including Supply Adj. Less ML1	76,389,775	78,656,308	75,251,644	76,765,909	
7	Excess Pressure Volumes	22,793,356	27,068,846	24,520,795	24,794,332	
8	Cumulative Adj. Supply Including Supply Adj. Less Excess Pressure and ML1	53,596,419	51,587,462	50,730,849	51,971,577	
	Consumption					
9	Residential	33,230,263	33,025,648	31,250,450	32,502,120	
10	Commercial	23,060,945	23,344,368	22,671,129	23,025,481	
11	Industrial	21,766,574	23,582,631	22,937,550	22,762,252	
12	Other	9,027	3,169	2,439	4,878	
13	Electric Gen.	307,341	470,912	404,820	394,358	
14	Company Use	135,786	119,026	133,876	129,563	
15	Subtotal Consumption	78,509,936	80,545,754	77,400,264	78,818,652	
16	ML1 Volumes	2,621,167	2,893,490	2,816,378	2,777,012	
17	Excess Pressure	22,567,679	26,800,838	24,278,015	24,548,844	
18	Total Consumption - Includes Company Use but not ML1 (18 = 15 - 16)	75,888,769	77,652,264	74,583,886	76,041,640	
19	Total Consumption-Includes Company Use Less ML1 and Excess Pressure (19 = 18 -17)	53,321,090	50,851,426	50,305,871	51,492,796	
	Retainage					
19	Retainage-Includes Company Use Less ML1	636,792	1,123,070	801,634	853,832	
20	Rate (20 = 19 / 6)	0.8%	1.4%	1.1%	1.0%	
21	Retainage - Includes Company Use but not ML1 nor Excess Pressure	411,115	855,062	558,854	608,344	
22	Rate (22 = 21 / 8)	0.8%	1.7%	1.1%	1.2%	(1)

(1) Rate to be in effect as of January 1, 2025.

COLUMBIA GAS OF PENNSYLVANIA, INC.
COMPUTATION OF CHANGE IN RATE PURSUANT TO SECTION 1307(f)
APPLICATION PERIOD: OCTOBER, 2024 THROUGH SEPTEMBER, 2025

Line No.	Description		Amount	
			(1)	
1	Purchased Gas Commodity Cost		$	
2	Commodity Cost of Gas (Exhibit JF-3, Schedule 1)		93,936,776	
3	Projected tariff sales for the twelve billing periods of			
4	October, 2024 through September, 2025		396,376,468	Therms
5	PGCC Rate - Exhibit JF-3, Schedule 5		0.20480	
6	Commodity (Over)/Under Collection			
7	Commodity E-Factor			
8	(Exhibit No. 1-E)		480,133	
9	Projected sales for the twelve billing periods of			
10	October, 2024 through September, 2025		396,376,468	Therms
11	Commodity E-Factor (Line 8/ Line 10)		0.00121	
12	Purchased Gas Demand Cost			
13	Demand cost of gas (Exhibit JF-3, Schedule 1)		90,415,169	
14	Less: Purchased Gas Demand recovered under Rate SS			
15	(Exhibit JF-2, Schedule 2, Sheet 2)		944,842	
16	Less: Purchased Gas Demand Cost allocated to Rates LTS, STS,			
17	SGS-TS and MLS (Exh JF-2, Sch 2, Page 3)		0	
18	Subtotal (Line 13 - Line 15 - Line 17)		89,470,327	
19	Projected sales for the twelve billing periods of			
20	October, 2024 through September, 2025	1_/	469,941,653	Therms
21	PGDC Rate prior to Capacity Release Credit (Line 18 / Line 20)		0.19039	
22	Off System Sales and Capacity Release Credit		(0.00582)	
23	PGDC Rate		0.18457	
24	Demand (Over)/Under Collection			
25	Demand E- Factor			
26	(Exhibit No. 1-E)		3,526,312	
27	Projected sales for the twelve billing periods of			
28	October, 2024 through September, 2025	1_/	469,941,653	Therms
29	Demand E-Factor (Line 26 / Line 28)		0.00750	
30	Total Purchased Gas Cost			
31	PGCC Rate (Line 5)		0.20480	
32	PGDC Rate (Line 23)		0.18457	
33	PGC Rate		0.38937	
34	Currently effective PGC		0.40337	
35	Increase (Decrease) in PGC		(0.01400)	
36	Net (Over) Under Collection			
37	Commodity E-Factor (Line 11)		0.00121	
38	Demand E-Factor (Line 29)		0.00750	
39	E-Factor		0.00871	
40	Currently effective E-Factor		0.00722	
41	Increase (Decrease) in E-Factor		0.00149	
42	PGC Rate		0.38937	
43	E-Factor		0.00871	
44	Total Rate		0.39808	
45	Currently effective Rate		0.41059	
46	Increase (Decrease) in Rate		(0.01251)	

1_/ Includes 73,565,185 Therm Transportation Quantities for the Company's Choice Program

COLUMBIA GAS OF PENNSYLVANIA, INC.
PURCHASED GAS COST RECOVERED UNDER RATES SS
AND COMPUTATION OF DAILY PURCHASED GAS DEMAND
APPLICATION PERIOD: OCTOBER, 2024 THROUGH SEPTEMBER, 2025

Line No.	Description	Detail (1)		Total (2)
1	Total estimated demand charges for the period			
2	October, 2024 through September, 2025	90,415,169		
3	Estimated Demand Quantity (Therms) 1_/	81,748,680		
4	Daily purchased gas demand rate (Line 2 / line 3)	$1.10601	per Therm	
5	Daily purchased gas demand (Therms)	854,280	Therms	
6	Daily purchased gas demand rate per Therm	$1.10601		
7	Total rate SS Daily Demand Cost to be			
8	Recovered (Line 5 x Line 6)			$944,842

1_/ Monthly Demand Billing Determinants x 12

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PROJECTED SALES QUANTITIES AND REVENUES FOR THE PERIOD
SALES AT PGCC AND PGDC RATES
OCTOBER, 2024 THROUGH SEPTEMBER, 2025

Line No.	Month	Sales Subject To PGCC (1) Therms	PGCC Rate 1_/ (2) $/Therm	PGCC Revenue (3=1x2) $	Sales Subject To PGDC (4) Therms	PGDC Rate 1_/ (5) $/Therm	PGDC Revenue (6=4x5) $	Purchased Gas Cost Revenue (7=3+6) $
1	October - 2024	9,459,646	0.20480	1,937,336	11,506,943	0.19039	2,190,807	4,128,143
2	November	25,388,003	0.20480	5,199,463	30,610,860	0.19039	5,828,002	11,027,465
3	December	55,676,190	0.20480	11,402,484	65,645,488	0.19039	12,498,244	23,900,728
4	January - 2025	75,752,468	0.20480	15,514,105	89,381,325	0.19039	17,017,310	32,531,415
5	February	76,948,963	0.20480	15,759,148	90,885,361	0.19039	17,303,664	33,062,812
6	March	63,699,539	0.20480	13,045,666	75,163,262	0.19039	14,310,333	27,355,999
7	April	42,335,811	0.20480	8,670,374	49,998,154	0.19039	9,519,149	18,189,523
8	May	19,504,058	0.20480	3,994,431	23,223,951	0.19039	4,421,608	8,416,039
9	June	9,697,441	0.20480	1,986,036	11,686,503	0.19039	2,224,993	4,211,029
10	July	6,166,610	0.20480	1,262,922	7,513,102	0.19039	1,430,419	2,693,341
11	August	5,731,398	0.20480	1,173,790	6,998,853	0.19039	1,332,512	2,506,302
12	September	6,016,341	0.20480	1,232,147	7,327,851	0.19039	1,395,150	2,627,297
13	Total	396,376,468		81,177,902	469,941,653		89,472,191	170,650,093

1_/ Excludes refunds and experienced over/undercollections

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PROJECTED SALES QUANTITIES AND REVENUES FOR THE PERIOD
SALES AT STANDBY RATE
OCTOBER, 2024 THROUGH SEPTEMBER, 2025

Line No.	Month	Daily Purchased Gas Demand Quantity (1) Therms	Daily Gas Demand Rate (2) $/Therm	Daily Purchased Gas Demand Revenue (3=1x2) $
1	October - 2024	71,190	1.10601	78,737
2	November	71,190	1.10601	78,737
3	December	71,190	1.10601	78,737
4	January - 2025	71,190	1.10601	78,737
5	February	71,190	1.10601	78,737
6	March	71,190	1.10601	78,737
7	April	71,190	1.10601	78,737
8	May	71,190	1.10601	78,737
9	June	71,190	1.10601	78,737
10	July	71,190	1.10601	78,737
11	August	71,190	1.10601	78,737
12	September	71,190	1.10601	78,737
13	Total	854,280		944,842

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PROJECTED SALES QUANTITIES AND REVENUES FOR THE PERIOD
SALES AT BANKING AND BALANCING RATES
OCTOBER, 2024 THROUGH SEPTEMBER, 2025

Line No.	Month	Lg. Quantity GDS Deliveries	Rate	Revenue	Sm. Quantity GDS Deliveries	Rate	Revenue	Total Trans. Revenue
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)	(7=3+6)
		Therms	$/Therm	$	Therms	$/Therm	$	$
1	October - 2024	0	0.00226	0	0	0.00697	0	0
2	November	0	0.00226	0	0	0.00697	0	0
3	December	0	0.00226	0	0	0.00697	0	0
4	January - 2025	0	0.00226	0	0	0.00697	0	0
5	February	0	0.00226	0	0	0.00697	0	0
6	March	0	0.00226	0	0	0.00697	0	0
7	April	0	0.00226	0	0	0.00697	0	0
8	May	0	0.00226	0	0	0.00697	0	0
9	June	0	0.00226	0	0	0.00697	0	0
10	July	0	0.00226	0	0	0.00697	0	0
11	August	0	0.00226	0	0	0.00697	0	0
12	September	0	0.00226	0	0	0.00697	0	0
13	Total	0		0	0		0	0

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PROJECTED TOTAL OVER/UNDERCOLLECTION
FOR THE 2024 1307(f) PERIOD
OCTOBER, 2024 THROUGH SEPTEMBER, 2025

Line No.	Month	Commodity Recoveries PGCC Revenue	Total Commodity Cost of Gas 1_/	Commodity Over/ (Under) collection	Demand Recoveries PGDC Revenue	Total Demand Cost of Gas 1_/	Demand Over/ (Under) collection	Total Over/ (Under) collection
		(1)	(2)	(3=1-2)	(4)	(5)	(6=4-5)	(7=3+6)
		$	$	$	$	$	$	$
1	October - 2024	1,937,336	2,883,148	(945,812)	2,269,544	8,491,934	(6,222,390)	(7,168,202)
2	November	5,199,463	8,149,508	(2,950,045)	5,906,739	8,662,861	(2,756,122)	(5,706,167)
3	December	11,402,484	16,829,389	(5,426,905)	12,576,981	8,699,471	3,877,510	(1,549,395)
4	January - 2025	15,514,105	21,618,764	(6,104,659)	17,096,047	8,699,471	8,396,576	2,291,917
5	February	15,759,148	18,980,099	(3,220,951)	17,382,401	8,699,471	8,682,930	5,461,979
6	March	13,045,666	11,431,877	1,613,789	14,389,070	8,699,471	5,689,599	7,303,388
7	April	8,670,374	7,221,496	1,448,878	9,597,886	6,490,415	3,107,471	4,556,349
8	May	3,994,431	2,889,425	1,105,006	4,500,345	6,394,415	(1,894,070)	(789,065)
9	June	1,986,036	1,009,693	976,343	2,303,730	6,394,415	(4,090,685)	(3,114,343)
10	July	1,262,922	923,511	339,411	1,509,156	6,394,415	(4,885,259)	(4,545,848)
11	August	1,173,790	856,463	317,327	1,411,249	6,394,415	(4,983,166)	(4,665,839)
12	September	1,232,147	1,143,402	88,745	1,473,887	6,394,415	(4,920,528)	(4,831,784)
13	Total	81,177,902	93,936,776	(12,758,875)	90,417,033	90,415,169	1,864	(12,757,010)

1_/ Refer to Exhibit 1-B, Schedule No. 1.

Columbia Gas of Pennsylvania, Inc.
Capacity Assignment Factor
Assignment of FT Only

Purchased Gas Demand Charge (PGDC) Paid By the CHOICE Customer
Rates Based on Projected Costs For 12 Months Ending September, 2025

$90,415,169		1. Projected Demand Costs Oct. 2024 through Sept. 2025 (Exh. 1-B, Sch. 1)
(944,842)		1a. Less Purchased Gas Demand Costs Recovered Under Rate SS (Exhibit JF-2, Schedule 1, Sheet 2)
0		1b. Less Purchased Gas Demand Allocated to Rates LTS, STS, SGS-TS, and MLS
3,526,312		1c. Experienced Demand Net Under/(Over) Collection (Exhibit No. 1-E)
$92,996,639		2. Total Adjusted Demand Costs per 1307(f) Filing (1) + (1a) + (1b) + (1c)
$120.15	per Dth	3. Unit FT Demand Charge Per Dth of TCO/EGTS capacity the marketer would pay TCO and EGTS. (Exhibit JF-2, Schedule 3, Sheet 2)
46,994	MMDth	4. Projected Sales & Choice Requirements for 12 billing periods of October, 2024 through September, 2025
47,516	MMDth	5. Projected Sales & Choice Requirements 12 months ended September 2025, including Unaccounted For @ 1.1%
21,755	MMDth	6. Annual Injections and Withdrawals, Normal Weather
1	Dth	7a. Quantity Delivered to the Customer
1.1%		7b. Unaccounted-for & Co. Use Factor from Volume Balancing System
1.0111	Dth	7c. Quantity Delivered to the City Gate. (7a)/(1-7b)
$1.9789	per Dth	8. Unit Demand Charge: (2) / (4)
($0.0582)	per Dth	9. OSS and Capacity Release Credit
0.0028	Dth	10. Average Daily FT Delivery: (7c) / 365 days
$0.3364	per Dth	11. Annual Demand Charge for the Assigned FT Capacity payable to the pipeline(s): (3) X (10)
$1.6425	per Dth	12. Annual Demand Charge for other capacity that CPA retains (8) - (11)
0.4629	Dth	13. Quantity Injected and Withdrawn to Deliver 1 Dth to the Customer: (6) / (4)
$0.0071		14a. Injection Charge @ $0.0153/Dth
$0.0050		14b. FSS Shrinkage @ 0.405% for gas at $2.6588/Dth
$0.0071		14c. Withdrawal Charge @ $0.0153/Dth
$0.0068		14d. SST Commodity Charge @ $0.0146/Dth
$0.0281		14e. SST retention @ 2.132% for gas at $2.6588/Dth
$0.0541	per Dth	14f. Total Annual Variable Storage Costs
		15. Credit to Purchased Gas Demand Charge for the CHOICE Customer:
$0.3364	per Dth	15a. For Demand Cost Paid to Pipelines: = (11)
($0.0541)	per Dth	15b. Less Storage Costs: = (14f)
$0.2823	per Dth	15c. Net Credit: (15a) + (15b)
$0.02823	per Therm	15d. Per Therm: (15c)/10 - Capacity Assignment Factor
$1.6384	per Dth	16. Purchased Gas Demand Charge Paid By the CHOICE Customer: (8)+(9) - (15c)
$0.16384	per Therm	17. Per Therm: (16)/10

Columbia Gas of Pennsylvania, Inc. (CPA)
CPA Capacity Assignment (PCA): Assignment of FT Capacity Only
CPA Capacity on TCO and EGTS. Cost of the Capacity Allocated to Marketers.

	TCO FT Capacity		EGTS FT Capacity		Total: TCO and EGTS
1. CPA FT Capacity on TCO and EGTS					
2. CPA Contract: Dth/d	129,716		5,000	1/	
3. Projected Demand Costs					
4. Annual Demand Cost 2/	$15,828,984		$356,958		
4a. Monthly Billing Determinants	129,716		5,000		
4b. Annual Demand Charge (4/ 4a)	$122.03		$71.39		
4c. Monthly Demand Charge (4b / number of months)	$10.169		$5.949		
Allocation Capacity and Costs.					
5. Retained Volume:	1.0000		1.0000		
6. Number of Months	12		12		
7. Capacity Allocation	0.9629	3/	0.0371	4/	
8. Unit Annual Cost of City Gate Capacity: (4c) x (5) x (6) x (7) $/Dth	$117.50		$2.65		$120.15

Notes:

1/ Non-storage EGTS FT capacity
2/ Projected demand costs for the period 12 months ended September, 2025.
3/ 129,716/(129,716+5,000) = 0.9629
4/ 5,000/(129,716+5,000) = 0.0371

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
For the Period October 2024 Through September 2025

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
1	Total Quantity													
2	DTH	1,760,000	4,511,000	7,078,000	8,566,000	7,795,000	5,825,000	2,769,000	1,093,000	362,000	333,000	309,000	419,000	40,820,000
3	Total Demand Costs	8,491,934	8,662,861	8,699,471	8,699,471	8,699,471	8,699,471	6,490,415	6,394,415	6,394,415	6,394,415	6,394,415	6,394,415	90,415,169
4	Total Commodity Costs	2,883,148	8,149,508	16,829,389	21,618,764	18,980,099	11,431,877	7,221,496	2,889,425	1,009,693	923,511	856,463	1,143,402	93,936,776
5	Total Estimated Gas Costs (Line 5 = Line 3 + Line 4)	11,375,082	16,812,369	25,528,860	30,318,235	27,679,570	20,131,348	13,711,911	9,283,840	7,404,108	7,317,926	7,250,878	7,537,817	184,351,945

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Demand Costs

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
1	Columbia Gas Transmission	7,539,076	7,539,076	7,539,076	7,539,076	7,539,076	7,539,076	5,550,613	5,550,613	5,550,613	5,550,613	5,550,613	5,550,613	78,538,134
2	Texas Eastern Transmission	297,325	297,325	333,935	333,935	333,935	333,935	284,405	284,405	284,405	284,405	284,405	284,405	3,636,820
3	Eastern Gas Transmission and Storage	254,680	296,325	296,325	296,325	296,325	296,325	254,680	254,680	254,680	254,680	254,680	254,680	3,264,385
4	Tennessee Gas	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	1,338,564
5	National Fuel Gas	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	1,170,840
6	Equitrans	216,736	346,018	346,018	346,018	346,018	346,018	216,600	120,600	120,600	120,600	120,600	120,600	2,766,426
7	Less Elective Balancing Svc. Credit	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	300,000
8	Total Demand Cost	8,491,934	8,662,861	8,699,471	8,699,471	8,699,471	8,699,471	6,490,415	6,394,415	6,394,415	6,394,415	6,394,415	6,394,415	90,415,169

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Commodity Costs

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
1	Term	119,931	1,275,638	4,154,838	4,897,325	4,338,412	1,927,653	67,384	70,682	69,569	74,231	75,066	64,107	17,134,836
2	Spot	4,613,737	71,694	8,105,978	9,323,888	7,368,198	1,011,538	15,244,612	10,889,435	9,151,748	9,204,592	8,617,510	7,062,832	90,665,762
3	Local	30,129	40,194	58,289	70,752	61,490	61,952	53,403	55,385	53,960	56,903	56,529	49,350	648,336
4	Storage	(1,880,649)	6,761,982	4,510,284	7,326,799	7,211,999	8,430,734	(8,143,903)	(8,126,077)	(8,265,584)	(8,412,215)	(7,892,642)	(6,032,887)	(14,512,158)
5	Total Commodity Cost	2,883,148	8,149,508	16,829,389	21,618,764	18,980,099	11,431,877	7,221,496	2,889,425	1,009,693	923,511	856,463	1,143,402	93,936,776

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Commodity Quantities

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
	Term													
1	Total-DTH	92,000	667,000	1,465,000	1,464,000	1,323,000	687,000	27,000	29,000	28,000	29,000	30,000	29,000	5,870,000
	Spot													
2	Total-DTH	3,197,000	39,000	2,918,000	2,796,000	2,251,000	356,000	5,915,000	4,253,000	3,450,000	3,401,000	3,210,000	2,875,000	34,661,000
	Local													
3	Total-DTH	22,000	21,000	22,000	22,000	20,000	22,000	21,000	22,000	21,000	22,000	22,000	21,000	258,000
	Storage													
4	Total-DTH	(1,551,000)	3,784,000	2,673,000	4,284,000	4,201,000	4,760,000	(3,194,000)	(3,211,000)	(3,137,000)	(3,119,000)	(2,953,000)	(2,506,000)	31,000
	Total - All Sources													
5	Total-DTH	1,760,000	4,511,000	7,078,000	8,566,000	7,795,000	5,825,000	2,769,000	1,093,000	362,000	333,000	309,000	419,000	40,820,000

COLUMBIA GAS OF PENNSYLVANIA, INC.

Monthly Average Cost of Gas
Commodity

Line No.	Description	2024 October	November	December	2025 January	February	March	April	May	June	July	August	September	Total
1	Term, Spot, and Local Costs	4,763,797	1,387,526	12,319,105	14,291,965	11,768,100	3,001,143	15,365,399	11,015,502	9,275,277	9,335,726	8,749,105	7,176,289	108,448,934
2	Term, Spot, and Local Volumes - DTH	3,311,000	727,000	4,405,000	4,282,000	3,594,000	1,065,000	5,963,000	4,304,000	3,499,000	3,452,000	3,262,000	2,925,000	40,789,000
3	Monthly Average Cost of Gas/Dth	1.4388	1.9086	2.7966	3.3377	3.2744	2.8180	2.5768	2.5594	2.6508	2.7044	2.6821	2.4534	2.6588

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Columbia Gas Transmission Corporation

Line No.	Description	2024 October	November	December	2025 January	February	March	April	May	June	July	August	September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	Columbia Gas Transmission													
	FTS													
1	Billing Determinant-Dth	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	
2	Less Capacity Release (1)	5,215	5,215	5,215	5,215	5,215	5,215	5,215	5,215	5,215	5,215	5,215	5,215	
3	Net Billing Determinant - Dth	129,716	129,716	129,716	129,716	129,716	129,716	129,716	129,716	129,716	129,716	129,716	129,716	
4	Demand Rate	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	
5	Demand Cost	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	15,828,984
	FSS-Reservation													
6	Billing Determinant-Dth	395,714	395,714	395,714	395,714	395,714	395,714	395,714	395,714	395,714	395,714	395,714	395,714	
7	Demand Rate	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	
8	Demand Cost	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	13,405,212
	FSS-Capacity													
9	Total-DTH	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	
10	Demand Rate	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	
11	Demand Cost	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	13,511,604
	SST													
12	Billing Determinant-Dth	395,714	395,714	395,714	395,714	395,714	395,714	197,857	197,857	197,857	197,857	197,857	197,857	
13	Demand Rate	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	
14	Demand Cost	3,976,926	3,976,926	3,976,926	3,976,926	3,976,926	3,976,926	1,988,463	1,988,463	1,988,463	1,988,463	1,988,463	1,988,463	35,792,334
15	Total TCO Demand Cost	7,539,076	7,539,076	7,539,076	7,539,076	7,539,076	7,539,076	5,550,613	5,550,613	5,550,613	5,550,613	5,550,613	5,550,613	78,538,134

(1) Columbia has included in the application period a projection for the release of 5,215 Dth of capacity to be released at the applicable maximum rate to a large industrial customer on Columbia's system and not subject to recall.

Exhibit JF-3
Schedule 3
Sheet 1 of 1

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Texas Eastern Transmission Corporation

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	FT1-TCO Delmont													
1	Billing Determinant-Dth	3,082	3,082	3,082	3,082	3,082	3,082	3,082	3,082	3,082	3,082	3,082	3,082	
2	Demand Rate	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	
3	Demand Cost	24,456	24,456	24,456	24,456	24,456	24,456	24,456	24,456	24,456	24,456	24,456	24,456	293,472
	FT1-Uniontown													
4	Billing Determinant-Dth	11,753	11,753	11,753	11,753	11,753	11,753	11,753	11,753	11,753	11,753	11,753	11,753	
5	Demand Rate	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	
6	Demand Cost	93,260	93,260	93,260	93,260	93,260	93,260	93,260	93,260	93,260	93,260	93,260	93,260	1,119,120
	CDS - Eagle/Rockwood													
7	Billing Determinant-Dth	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342	
8	Demand Rate	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	
9	Demand Cost	55,056	55,056	55,056	55,056	55,056	55,056	55,056	55,056	55,056	55,056	55,056	55,056	660,672
	CDS - Rockwood													
10	Billing Determinant-Dth	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	
11	Demand Rate	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	
12	Demand Cost	100,004	100,004	100,004	100,004	100,004	100,004	100,004	100,004	100,004	100,004	100,004	100,004	1,200,048
	CDS - Chambersburg													
13	Billing Determinant-Dth	158	158	158	158	158	158	158	158	158	158	158	158	
14	Demand Rate	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	
15	Demand Cost	3,716	3,716	3,716	3,716	3,716	3,716	3,716	3,716	3,716	3,716	3,716	3,716	44,592
	FT1-TCO @ Eagle Zone 3 Zone 3													
16	Billing Determinant-Dth	0	0	10,000	10,000	10,000	10,000	0	0	0	0	0	0	
17	Demand Rate	0.0000	0.0000	4.9530	4.9530	4.9530	4.9530	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
18	Demand Cost	0	0	49,530	49,530	49,530	49,530	0	0	0	0	0	0	198,120
	FT1-MX													
19	Billing Determinant-Dth	100	100	100	100	100	100	100	100	100	100	100	100	
20	Demand Rate	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	
21	Demand Cost	161	161	161	161	161	161	161	161	161	161	161	161	1,932
	FT1-M2													
22	Billing Determinant-Dth	3,200	3,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	
23	Demand Rate	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	
24	Demand Cost	20,672	20,672	7,752	7,752	7,752	7,752	7,752	7,752	7,752	7,752	7,752	7,752	118,864
25	Total TETCO Demand Cost	297,325	297,325	333,935	333,935	333,935	333,935	284,405	284,405	284,405	284,405	284,405	284,405	3,636,820

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Eastern Gas Transmission and Storage

Line No.	Description	2024 October	November	December	2025 January	February	March	April	May	June	July	August	September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	Eastern Gas Transmission and Storage													
	GSS - Reservation													
1	Billing Determinant-Dth	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	
2	Demand Rate	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	
3	Demand Cost	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	770,376
	GSS - Capacity													
4	Billing Determinant-Dth	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	
5	Demand Rate	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	
6	Demand Cost	48,276	48,276	48,276	48,276	48,276	48,276	48,276	48,276	48,276	48,276	48,276	48,276	579,312
	FTNN													
7	Billing Determinant-Dth	0	6,000	6,000	6,000	6,000	6,000	0	0	0	0	0	0	
8	Total-DTH	0.0000	5.9493	5.9493	5.9493	5.9493	5.9493	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
9	Demand Cost	0	35,696	35,696	35,696	35,696	35,696	0	0	0	0	0	0	178,480
	FT													
10	Billing Determinant-Dth	23,903	24,903	24,903	24,903	24,903	24,903	23,903	23,903	23,903	23,903	23,903	23,903	
11	Total-DTH	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	
12	Demand Cost	142,206	148,155	148,155	148,155	148,155	148,155	142,206	142,206	142,206	142,206	142,206	142,206	1,736,217
13	Total DTI Demand Cost	254,680	296,325	296,325	296,325	296,325	296,325	254,680	254,680	254,680	254,680	254,680	254,680	3,264,385

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Tennessee Gas Pipeline Company

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	Tennessee Gas FT-A (Direct) New Castle - 219 Line													
1	Billing Determinant-Dth	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	
2	Demand Rate	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	
3	Demand Cost	76,979	76,979	76,979	76,979	76,979	76,979	76,979	76,979	76,979	76,979	76,979	76,979	923,748
	Tennessee Gas FT-A (Direct) Pitt Teminal - 219 Line													
4	Billing Determinant-Dth	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	
5	Demand Rate	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	
6	Demand Cost	34,568	34,568	34,568	34,568	34,568	34,568	34,568	34,568	34,568	34,568	34,568	34,568	414,816
7	Total Tennessee Gas Demand Cost	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	1,338,564

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
National Fuel Gas Supply

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	National - FT													
1	Billing Determinant-Dth	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304	
2	Demand Rate	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	
3	Demand Cost	35,330	35,330	35,330	35,330	35,330	35,330	35,330	35,330	35,330	35,330	35,330	35,330	423,960
	National - EFT													
4	Billing Determinant-Dth	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	
5	Demand Rate	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	
6	Demand Cost	33,792	33,792	33,792	33,792	33,792	33,792	33,792	33,792	33,792	33,792	33,792	33,792	405,504
	National - ESS Reservation													
7	Billing Determinant-Dth	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	
8	Demand Rate	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	
9	Demand Cost	9,481	9,481	9,481	9,481	9,481	9,481	9,481	9,481	9,481	9,481	9,481	9,481	113,772
	National - ESS Capacity													
10	Billing Determinant-Dth	267,143	267,143	267,143	267,143	267,143	267,143	267,143	267,143	267,143	267,143	267,143	267,143	
11	Demand Rate	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	
12	Demand Cost	18,967	18,967	18,967	18,967	18,967	18,967	18,967	18,967	18,967	18,967	18,967	18,967	227,604
13	Total National Fuel Demand Cost	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	1,170,840

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Equitrans

Line		2024			2025									
No.	Description	October	November	December	January	February	March	April	May	June	July	August	September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	Equitrans													
	FTS													
1	Billing Determinant-Dth	27,092	26,741	26,741	26,741	26,741	26,741	27,075	15,075	15,075	15,075	15,075	15,075	
2	Demand Rate	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
3	Demand Cost	216,736	213,928	213,928	213,928	213,928	213,928	216,600	120,600	120,600	120,600	120,600	120,600	2,105,976
	FTS													
4	Billing Determinant-Dth	0	18,870	18,870	18,870	18,870	18,870	0	0	0	0	0	0	
5	Demand Rate	0.0000	7.0000	7.0000	7.0000	7.0000	7.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
6	Demand Cost	0	132,090	132,090	132,090	132,090	132,090	0	0	0	0	0	0	660,450
7	Total Equitrans Demand Cost	216,736	346,018	346,018	346,018	346,018	346,018	216,600	120,600	120,600	120,600	120,600	120,600	2,766,426

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Term Contracts

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
	TERM													
	COLUMBIA TRANSMISSION													
1	Quantity - DTH	0	0	547,000	547,000	494,000	0	0	0	0	0	0	0	1,588,000
2	Rate-$/DTH	0.0000	0.0000	2.7218	3.3007	3.1561	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
3	Cost-$	0	0	1,488,825	1,805,483	1,559,113	0	0	0	0	0	0	0	4,853,421
	TEXAS EASTERN													
4	Quantity - DTH	92,000	667,000	687,000	686,000	620,000	687,000	27,000	29,000	28,000	29,000	30,000	29,000	3,611,000
5	Rate-$/DTH	1.3036	1.9125	2.7766	3.2604	3.1654	2.8059	2.4957	2.4373	2.4846	2.5597	2.5022	2.2106	
6	Cost-$	119,931	1,275,638	1,907,524	2,236,634	1,962,548	1,927,653	67,384	70,682	69,569	74,231	75,066	64,107	9,850,967
	TENNESSEE GAS PIPELINE													
7	Quantity - DTH	0	0	231,000	231,000	209,000	0	0	0	0	0	0	0	671,000
8	Rate-$/DTH	0.0000	0.0000	3.2835	3.7022	3.9079	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
9	Cost-$	0	0	758,489	855,208	816,751	0	0	0	0	0	0	0	2,430,448
	CAP													
10	Quantity - DTH	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Rate-$/DTH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
12	Cost-$	0	0	0	0	0	0	0	0	0	0	0	0	0
	LESS CAP BILLING													
13	Quantity - DTH	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Rate-$/DTH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
15	Cost-$	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Total - DTH	92,000	667,000	1,465,000	1,464,000	1,323,000	687,000	27,000	29,000	28,000	29,000	30,000	29,000	5,870,000
17	Total Term Commodity													
18	Cost-$	119,931	1,275,638	4,154,838	4,897,325	4,338,412	1,927,653	67,384	70,682	69,569	74,231	75,066	64,107	17,134,836

*Beginning October 1, 2021, CAP customers will be served by Columbia sales service until a new supplier submits a successful bid to provide CAP gas supply.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Spot and Local Purchases

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
	SPOT													
	Base													
1	Quantity - DTH	1,379,000	37,000	2,445,000	2,718,000	2,251,000	356,000	3,440,000	3,105,000	2,893,000	2,864,000	993,000	960,000	23,441,000
2	Rate-$/DTH	1.5728	1.8375	2.8071	3.3357	3.2733	2.8414	2.6018	2.5809	2.6887	2.7434	2.8732	2.6909	
3	Cost-$	2,168,891	67,988	6,863,360	9,066,433	7,368,198	1,011,538	8,950,192	8,013,695	7,778,409	7,857,098	2,853,088	2,583,264	64,582,154
	Swing													
4	Quantity - DTH	1,818,000	2,000	473,000	78,000	0	0	2,475,000	1,148,000	557,000	537,000	2,217,000	1,915,000	11,220,000
5	Rate-$/DTH	1.3448	1.8528	2.6271	3.3007	0.0000	0.0000	2.5432	2.5050	2.4656	2.5093	2.6001	2.3392	
6	Cost-$	2,444,846	3,706	1,242,618	257,455	0	0	6,294,420	2,875,740	1,373,339	1,347,494	5,764,422	4,479,568	26,083,608
7	Total - DTH	3,197,000	39,000	2,918,000	2,796,000	2,251,000	356,000	5,915,000	4,253,000	3,450,000	3,401,000	3,210,000	2,875,000	34,661,000
8	Total Spot													
9	Commodity Cost - $	4,613,737	71,694	8,105,978	9,323,888	7,368,198	1,011,538	15,244,612	10,889,435	9,151,748	9,204,592	8,617,510	7,062,832	90,665,762
	Local Direct													
10	Quantity - DTH	22,000	21,000	22,000	22,000	20,000	22,000	21,000	22,000	21,000	22,000	22,000	21,000	258,000
11	Rate-$/DTH	1.3695	1.9140	2.6495	3.2160	3.0745	2.8160	2.5430	2.5175	2.5695	2.5865	2.5695	2.3500	
12	Cost-$	30,129	40,194	58,289	70,752	61,490	61,952	53,403	55,385	53,960	56,903	56,529	49,350	648,336
13	Total - DTH	22,000	21,000	22,000	22,000	20,000	22,000	21,000	22,000	21,000	22,000	22,000	21,000	258,000
14	Total Local													
15	Commodity Cost - $	30,129	40,194	58,289	70,752	61,490	61,952	53,403	55,385	53,960	56,903	56,529	49,350	648,336

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs

Storage

Line		2024			2025									
No.	Description	October	November	December	January	February	March	April	May	June	July	August	September	Total
	EASTERN - GSS													
1	Injections - DTH	(204,000)	0	0	0	0	0	(179,000)	(252,000)	(253,000)	(254,000)	(253,000)	(252,000)	(1,647,000)
2	Injection Rate - $/Dth	1.4388	1.9086	2.7966	3.3377	3.2744	2.8180	2.5768	2.5594	2.6508	2.7044	2.6821	2.4534	
3	Withdrawals - DTH	0	294,000	0	552,000	493,000	337,000	0	0	0	0	0	0	1,676,000
4	Withdrawl Rate - $/Dth	1.8143	1.8143	1.8142	1.8143	1.8143	1.8142	2.2173	2.3421	2.4250	2.4841	2.5174	2.5094	
5	Cost-$	(293,515)	533,404	0	1,001,494	894,450	611,385	(461,247)	(644,969)	(670,652)	(686,918)	(678,571)	(618,257)	(1,013,396)
6	Injection Rate $/Dth	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	
7	Withdrawl Rate $/Dth	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	
8	Cost - $	8,017	7,526	0	14,131	12,621	8,627	7,035	9,904	9,943	9,982	9,943	9,904	107,633
	EQUITRANS - SS													
9	Injections - DTH	(194,000)	0	0	0	0	0	(294,000)	(214,000)	(214,000)	(216,000)	(214,000)	(214,000)	(1,560,000)
10	Injection Rate - $/Dth	1.4388	1.9086	2.7966	3.3377	3.2744	2.8180	2.5768	2.5594	2.6508	2.7044	2.6821	2.4534	
11	Withdrawals - DTH	0	355,000	210,000	230,000	249,000	517,000	0	0	0	0	0	0	1,561,000
12	Withdrawl Rate - $/Dth	1.8143	1.8143	1.8142	1.8143	1.8143	1.8142	2.2173	2.3421	2.4250	2.4841	2.5174	2.5094	
13	Cost-$	(279,127)	644,077	380,982	417,289	451,761	937,941	(757,579)	(547,712)	(567,271)	(584,150)	(573,969)	(525,028)	(1,002,786)
14	Inject/With. Rate $/DTH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
15	Cost - $	0	0	0	0	0	0	0	0	0	0	0	0	0
	TCO - FSS													
16	Injections - DTH	(1,317,000)	0	0	0	0	0	(2,803,000)	(3,057,000)	(3,055,000)	(3,055,000)	(2,895,000)	(2,414,000)	(18,596,000)
17	Injection Rate - $/Dth	1.4388	1.9086	2.7966	3.3377	3.2744	2.8180	2.5768	2.5594	2.6508	2.7044	2.6821	2.4534	
18	Withdrawals - DTH	0	3,247,000	2,916,000	4,179,000	4,074,000	4,180,000	0	0	0	0	0	0	18,596,000
19	Withdrawl Rate - $/Dth	1.8143	1.8143	1.8142	1.8143	1.8143	1.8142	2.2173	2.3421	2.4250	2.4841	2.5174	2.5094	
20	Cost-$	(1,894,900)	5,891,032	5,290,207	7,581,960	7,391,458	7,583,356	(7,222,770)	(7,824,086)	(8,098,194)	(8,261,942)	(7,764,680)	(5,922,508)	(13,251,067)
21	Inject/With. Rate $/DTH	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	
22	Cost - $	20,150	49,679	44,615	63,939	62,332	63,954	42,886	46,772	46,742	46,742	44,294	36,934	569,039
	NATIONAL FUEL - ESS													
23	Injections - DTH	(48,000)	0	0	0	0	0	0	(25,000)	(47,000)	(48,000)	(48,000)	(47,000)	(263,000)
24	Injection Rate - $/Dth	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2.5768	2.5594	2.6508	2.7044	2.6821	2.4534	
25	Withdrawals - DTH	0	54,000	44,000	47,000	48,000	61,000	9,000	0	0	0	0	0	263,000
26	Withdrawl Rate - $/Dth	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2.2173	2.3421	2.4250	2.4841	2.5174	2.5094	
27	Cost-$	0	0	0	0	0	0	19,956	(63,985)	(124,588)	(129,811)	(128,741)	(115,310)	(542,479)
28	Inject/With. Rate $/DTH	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	
29	Cost - $	1,834	2,063	1,681	1,795	1,834	2,330	344	955	1,795	1,834	1,834	1,795	20,094
30	Quantity - DTH	(1,763,000)	3,950,000	3,170,000	5,008,000	4,864,000	5,095,000	(3,267,000)	(3,548,000)	(3,569,000)	(3,573,000)	(3,410,000)	(2,927,000)	30,000
31	Total Purchase Cost	(2,467,542)	7,068,513	5,671,189	9,000,743	8,737,669	9,132,682	(8,421,640)	(9,080,752)	(9,460,705)	(9,662,821)	(9,145,961)	(7,181,103)	(15,267,249)
32	Total Inject/With. Cost	30,001	59,268	46,296	79,865	76,787	74,911	50,265	57,631	58,480	58,558	56,071	48,633	676,672

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Storage Transportation Charges

Line		2024			2025									
No.	Description	October	November	December	January	February	March	April	May	June	July	August	September	Total
	TCO - SST													
1	Injections - DTH	(1,317,000)	0	0	0	0	0	(2,803,000)	(3,057,000)	(3,055,000)	(3,055,000)	(2,895,000)	(2,414,000)	(18,596,000)
2	Withdrawals - DTH	0	3,247,000	2,916,000	4,179,000	4,074,000	4,180,000	0	0	0	0	0	0	18,596,000
3	Trans. Chrg. $/Dth	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	
4	Cost-$	19,228	47,406	42,574	61,013	59,480	61,028	40,924	44,632	44,603	44,603	42,267	35,244	543,002
	EASTERN - GSS													
5	Injections - DTH	(204,000)	0	0	0	0	0	(179,000)	(252,000)	(253,000)	(254,000)	(253,000)	(252,000)	(1,647,000)
6	Withdrawals - DTH	0	294,000	0	552,000	493,000	337,000	0	0	0	0	0	0	1,676,000
7	Trans. Chrg. $/Dth	0.0146	0.0112	0.0112	0.0112	0.0112	0.0112	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	
8	Cost-$	2,978	3,293	0	6,182	5,522	3,774	2,613	3,679	3,694	3,708	3,694	3,679	42,816
	EQUITRANS - SS													
9	Injections - DTH	(194,000)	0	0	0	0	0	(294,000)	(214,000)	(214,000)	(216,000)	(214,000)	(214,000)	(1,560,000)
10	Withdrawals - DTH	0	355,000	210,000	230,000	249,000	517,000	0	0	0	0	0	0	1,561,000
11	Trans. Chrg. $/Dth	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
12	Cost-$	0	0	0	0	0	0	0	0	0	0	0	0	0
	NATIONAL FUEL													
13	Injections - DTH	(48,000)	0	0	0	0	0	0	(25,000)	(47,000)	(48,000)	(48,000)	(47,000)	(263,000)
14	Withdrawals - DTH	0	54,000	44,000	47,000	48,000	61,000	9,000	0	0	0	0	0	263,000
15	Trans. Chrg. $/Dth	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	
16	Cost-$	1,138	1,280	1,043	1,114	1,138	1,446	213	593	1,114	1,138	1,138	1,114	12,469
17	Total Storage - DTH	(1,763,000)	3,950,000	3,170,000	5,008,000	4,864,000	5,095,000	(3,267,000)	(3,548,000)	(3,569,000)	(3,573,000)	(3,410,000)	(2,927,000)	30,000
18	Total EUB - DTH	212,000	(166,000)	(497,000)	(724,000)	(663,000)	(335,000)	73,000	337,000	432,000	454,000	457,000	421,000	1,000
19	Total DTH	(1,551,000)	3,784,000	2,673,000	4,284,000	4,201,000	4,760,000	(3,194,000)	(3,211,000)	(3,137,000)	(3,119,000)	(2,953,000)	(2,506,000)	31,000
20	Total Purchase Cost	(2,467,542)	7,068,513	5,671,189	9,000,743	8,737,669	9,132,682	(8,421,640)	(9,080,752)	(9,460,705)	(9,662,821)	(9,145,961)	(7,181,103)	(15,809,728)
21	Total Choice Bank Cost	533,548	(417,778)	(1,250,818)	(1,822,118)	(1,668,597)	(843,107)	183,722	848,140	1,087,230	1,142,599	1,150,149	1,059,546	2,517
22	Total Inject/With. Cost	30,001	59,268	46,296	79,865	76,787	74,911	50,265	57,631	58,480	58,558	56,071	48,633	696,766
23	Total Transp. Charge	23,344	51,979	43,617	68,309	66,140	66,248	43,750	48,904	49,411	49,449	47,099	40,037	598,287
24	Total Storage Cost	(1,880,649)	6,761,982	4,510,284	7,326,799	7,211,999	8,430,734	(8,143,903)	(8,126,077)	(8,265,584)	(8,412,215)	(7,892,642)	(6,032,887)	(14,512,158)

§ 53.64(i)(1)(iv)(v)

(i) Utilities shall comply with the following:

(1) Thirty days prior to the filing of a tariff reflecting increases or decreases in purchased gas expenses, gas utilities under 66 Pa.C.S. § 1307(f) recovering expenses under that section shall file a statement for the 12-month period ending 2 months prior to the filing date under 66 Pa.C.S. § 1307(f) as published in accordance with subsection (b) which shall specify:

(iv) Evidence explaining how actual costs incurred differ from the costs allowed under subparagraph (ii).

(v) How these costs are consistent with a least cost fuel procurement policy, as required by 66 Pa.C.S. § 1318 (relating to determination of just and reasonable natural gas rates).

Response:

Exhibit No. 1-F, Schedule 1 of Columbia's 2024 1307(f) filed March 1, 2024, constitutes the Company's Statement of Over/Under Collections From Gas Cost Rate, as required by Section 53.64(i)(1) for the twelve month period ended January 31, 2024. Exhibit No. 1-F, Schedule 1, Sheet 1 indicates that Columbia was under-collected by $5,994,826 at January 31, 2024, resulting from gas costs of $217,213,706 and gas cost recoveries of $211,218,880.

A company’s experienced over-collections or under-collections are caused by variances that occur between projected and actual gas costs, and between projected and actual gas cost recoveries.

The projection of gas cost recoveries follows the 1307(f) cycle through a period of under-collections during months of high usage, followed by a period of over-collections occurring during months of low usage. In its PGC filing effective January 1, 2023, Columbia projected gas costs for February 2023 through September 2023 of $157,937,839. Gas cost recoveries were projected at $185,024,639 for this same period of time. Accordingly, these months were projected to produce a net over-collection of $27,086,800 (Exhibit 1-A, Schedule 2, Sheet 4).

Actual gas costs for the months of February 2023 through September 2023 (2024 1307(f) Exhibit 1-F, Schedule 1, Sheet 1) totaled $135,690,187, a $22,247,652 decrease from the projections included in the January 1, 2023 PGC filing. As Columbia progressed through the 2022 1307(f) period and incrementally adjusted its recovery rates in subsequent filings, recoveries for the same period of time were recorded at $137,307,602, representing an decrease in gas cost recoveries of $47,717,037 from the January 1, 2023 PGC filing projections. In total Columbia experienced a net over-collection for the months of February 2023 through September 2023, which ended the 2022 1307(f) cycle, in the amount of $1,617,415.

As Columbia’s computation of historic reconciliation period over/under collections overlaps two separate 1307(f) periods, the remaining months of October 2023 through January 2024 will now be discussed.

In the October 1, 2023 PGC filing (Exhibit 1-A,Schedule 2, Sheet 4), Columbia projected gas costs for the months of October 2023 through January 2024 to total $91,532,478 with gas cost recoveries for the same period projected at $83,260,652, for an expected under-collection of $8,271,826. Columbia's actual gas costs for the months of October 2023 through January 2024 (2024 1307(f) Exhibit 1-F, Schedule 1) were $81,523,519, which is a decrease from October's gas cost projections of $10,008,959. As Columbia progressed through the 2023 1307(f) period and incrementally adjusted its recovery rates in subsequent filings, recoveries for the months of October 2023 through January 2024, were recorded at $73,911,278 (2024 1307(f) Exhibit 1-F, Schedule 1). This is a decrease of $9,349,374 when compared with the October 1, 2023 PGC gas cost recovery projections. Overall, the net variance between actual gas costs and gas cost recoveries for the months of October 2023 through January 2024 resulted in a net under-collection of $7,612,241.

Together the net over-collection from the 2022 1307(f) months of February 2023 through September 2023 of $1,617,415 and the net under-collection of $7,612,241 for the 2023 1307(f) months of October 2023 through January 2024 results in a total net under-collection of $5,994,826 for the twelve month period ending January 31, 2024. The net under-collections consists of a commodity over-collection of $4,572,658 and a demand under-collection of $10,567,485.

COLUMBIA STATEMENT NO. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2024-3047014
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF

NICOLE PALONEY

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2024

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Nicole Paloney, and my business address is 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc., ("Columbia" or "the Company") as Director of Rates and Regulatory Affairs.

Q. What are your responsibilities as Director of Rates and Regulatory Affairs?

A. I am responsible for developing and directing rate activity on behalf of the Company before the Pennsylvania Public Utility Commission ("Commission") as well as coordinating and representing the Company's position in a variety of regulatory matters and proceedings.

Q. What is your educational and professional background?

A. I have a Bachelor of Science in Business and Administration with an emphasis in Accounting and Finance from The Ohio State University. In 1998, I was hired as a staff auditor for Deloitte, primarily serving middle market clients in a variety of industries, including manufacturing, public pension systems and not for profit clients. I was promoted to manager in 2004 and served in that capacity until I left Deloitte in July 2005. From August 2005 until August 2008, I was employed by Cardinal Health in Dublin, Ohio. Cardinal Health provides pharmaceutical and medical products to the Health Care industry and is also a manufacturer of medical and surgical products. I was a manager in Internal Audit during my tenure at Cardinal, with responsibility over internal audits that took place in the manufacturing and corporate segments of the company.

In August 2008, I joined NiSource Corporate Services Company ("NCSC") as an Internal Audit Manager, with responsibility for internal audits that took place in NiSource Inc.'s Gas Distribution segment. In September 2011, I transitioned to the Regulatory Strategy and Support group in the role of Project Manager, providing support to the state regulatory teams in Pennsylvania and Maryland. In May 2014, I began my role as Director of Rates and Regulatory Affairs for the Company, until April 2019 when I took a temporary assignment in the NCSC legal department, providing business support to the legal team in Massachusetts. I returned to my role as Director of Rates and Regulatory Affairs in November 2019.

Q. Have you testified before this or any other Commission?

A. Yes. I have testified before this Commission on behalf of Columbia in Company base rate proceedings at Docket Nos. R-2015-2468056, R-2016-2529660, R-2018-2647577, R-2021-3024296 and R-2022-3031211. I have also testified before this Commission in the Company's Purchased Gas Cost ("PGC") proceedings at Docket Nos. R-2020-3018993, R-2021-3024349, R-2022-3031172 and R-2023-3038630. I also have testified before the Maryland Public Service Commission on behalf of Columbia Gas of Maryland, Inc. as a cost of service witness in Case No. 9316 and as a policy witness in Case Nos. 9354, 9480 and 9680.

Q. Please describe the scope of your testimony in this proceeding.

A. I am responsible for the overall presentation of Columbia's case in this PGC proceeding. Additionally, I am responsible for Exhibit No. 1 which sets forth the proposed tariff filed in this proceeding. I am also responsible for Exhibit No. 7, filed in response to the Commission's requirement that the Company provide a list of agreements that exist between Columbia and other utilities, pipelines or jurisdictional customers to transport gas through its system. I am also sponsoring Exhibit No. 9, submitted in response to the Commission's regulations that require the Company to provide a schedule depicting historic monthly end-user transportation throughput (known on Columbia's system as Choice Service and General Distribution Service) by customer, and Exhibit No. 11, which provides a detailed explanation of each rate structure or rate allocation change proposed in the filing. Exhibit NP-1, attached to my testimony, is proposed Tariff Supplement No. 379, which contains the rate changes identified by Witness Fischer in Columbia Statement No. 2.

II. SPONSORED EXHIBITS

Q. Were the exhibits that you are sponsoring prepared by you or by persons working under your direction?

A. Yes, they were.

Q. Is the information contained within the exhibits that you are sponsoring true and correct to the best of your knowledge and belief?

A. Yes, it is.

Q. Please describe briefly the area Columbia serves in the Commonwealth.

A. Columbia is engaged in the business of furnishing natural gas distribution service to more than 445,000 customers pursuant to certificates of public convenience and necessity issued by the Commission. Columbia provides service to 450 communities in 26 counties in western and south-central Pennsylvania.

Q. Please identify the scope of the testimony of the Company's other witnesses in this proceeding.

A. In Columbia Statement No. 1, Tina Monnig, Manager of Supply and Capacity Management with NCSC, will testify regarding the Company's gas supply plan, including information in support of the Company's least cost procurement strategy as contained in Exhibit No. 5. Ms. Monnig will also testify regarding the Company's involvement in relevant Federal Energy Regulatory Commission proceedings in support of Exhibit No. 3. Further, Ms. Monnig will support Exhibit No. 2, Exhibit No. 4, Exhibit No. 10, and Exhibit Nos. 12 through 15.

In Columbia Statement No. 2, Jessica Fischer, Lead Regulatory Analyst with NCSC, will testify regarding Exhibit Nos. 1-A through 1-F, which are filed to comply with Commission requirements in Title 52 of Pennsylvania Code Sections 53.64, *et seq*.

In Columbia Statement No. 4, Patrick Pluard, Director of Portfolio Optimization, will support Exhibit Nos. 1-D-1 through 1-D-3, Exhibit No. 6, and Exhibit Nos. 8-A through 8-E. Mr. Pluard will also discuss the Company's gas purchasing and procurement strategies to acquire the least cost reliable gas supplies to serve its customers, the Company's Unified Sharing Mechanism, and an update on the hedging program approved in Docket R-2023-3038630.

Q. Please explain Exhibit No. 1.

A. Exhibit No. 1 sets forth that the proposed tariff filed in this proceeding for recovery of purchased gas costs beginning October 1, 2024, will be submitted with testimony and is attached hereto as Exhibit NP-1. The tariff includes the proposed rates for each rate schedule, a PGC Rider that describes the manner in which the Company will recover its purchased gas costs from sales customers, and rates associated with standby service.

Q. Turning to Exhibit No. 7, would you please describe that exhibit?

A. Exhibit No. 7 was included in the pre-filing data submitted by Columbia in this proceeding on March 1, 2024. It was submitted in accordance with § 53.64(c)(8) of the Commission's regulations, which requires the Company to provide:

> A list of agreements to transport gas by the utility through its system, for other utilities, pipelines, or jurisdictional customers including the quantity and price of said transportation.

As noted in Exhibit No. 7, Columbia does not presently transport gas for other utilities or interstate pipelines.

Q. Please describe Exhibit No. 9.

A. Exhibit No. 9 provides a summary of transportation throughput, by customer, by month. This exhibit is submitted in compliance with § 53.64(c)(9) of the Commission's regulations, which requires the Company to provide a schedule depicting historic monthly end-user transportation throughput. Exhibit No. 9, Schedule 1 shows the throughput for CHOICE℠ customers by rate schedule by month for the period February 1, 2023, through January 31, 2024. Exhibit No. 9, Schedule 2 shows throughput for General Distribution Service, which represents commercial and industrial customers purchasing their gas supply from marketers by month by rate schedule for the same period.

Q. Please explain Exhibit No. 11.

A. Exhibit No. 11 is submitted pursuant to § 53.64(c)(11) of the Commission's regulations, which requires the Company to detail rate structure or rate allocation changes proposed in this filing. As noted in Exhibit No. 11, Columbia has not proposed any rate structure or rate allocation changes in this filing.

III. PIPELINE PENALTY CREDITS AND REFUNDS

Q. Please explain the ratemaking treatment of pipeline penalty credits and pipeline refunds.

A. As a result of a variety of Commission orders issued prior to 2018, Columbia had been permitted to use the residential portion of certain pipeline penalty credits and refunds to help fund its Hardship Fund. Pursuant to the Commission Order issued June 14, 2018 in Docket P-2018-3000160, Columbia was granted approval on an ongoing basis to use the residential portion of pipeline penalty credits and refunds received as a funding source for the Hardship Fund. The June 14, 2018 Order caps the balance of penalty credits and pipeline refunds to be retained at any one time for the Hardship Fund at $750,000. From April 21, 2022 through February 2, 2023, the Company's Hardship Fund balance was fully funded. Therefore, between April 21, 2022 and February 2, 2023, all residential and non-residential penalty credits and refunds received were distributed to customers through rates filed in the quarterly PGC filing. From February 2, 2023 through February 27, 2023, the Company's Hardship Fund balance fell below the $750,000 cap. Therefore, between those dates, the residential portion of penalty credits and refunds received were allocated to the Hardship Fund, and the non-residential portion of pipeline penalty credits and refunds received flowed through to non-residential customers through rates filed in the quarterly PGC filing. As of February 27, 2023, the Company's Hardship fund balance was fully funded, but as of March 14, 2024, the balance fell below the $750,000 cap. Therefore, between February 27, 2023 and March 14, 2024, all residential and non-residential penalty credits and refunds received were distributed to customers through rates filed in the quarterly PGC filing. Below is a table showing the recent pipeline penalty credits and pipeline refunds received by Columbia, the month and year they were received, the original dollar amount recorded and their disposition.

Columbia Gas of Pennsylvania, Inc.					
Docket	Date Received	Amount	Hardship Fund	Non-Residential	Residential
July 1, 2023 PGC Filing					
Eastern Gas and Transmission: Supplier Refund Docet No. RP21-1187	February 2023	546,400	375,000	145,938	25,462
		546,400	375,000	145,938	25,462
Docket	Date Received	Amount			
October 1, 2023 PGC Filing					
Texas Eastern Transmission: Penalty Credit Docket No. RP22-1144	October 2022	3,912			
Columbia Gas Transmission, LLC: Penalty Credit Docket No. RP23-318	December 2022	50,736			
Texas Eastern Transmission: Penalty Credit Docket No. RP23-25	December 2022	279			
Texas Eastern Transmission: Supplier Refund Docket Nos. RP21-1001 and RP21-1188	April 2023	1,173,791			
Texas Eastern Transmission: Penalty Credit Docket No RP23-451	April 2023	2,646			
Texas Eastern Transmission: Penalty Credit Docket No RP23-664	May 2023	45,641			
Eastern Gas Transmission and Storage: Penalty Credit Docket No RP23-860	July 2023	5,300			
		1,282,306			
Docket	Date Received	Amount			
Future PGC Filing					
Texas Eastern Transmission: Penalty Credit Docket No. RP-23-980	October 2023	4,067			
Texas Eastern Transmission: Penalty Credit Docket No. RP-24-68	December 2023	485			
Columbia Gas Transmission, LLC: Penalty Credit Docket No. RP-24-286	December 2023	510,386			
		514,938			

The non-residential portion flowed through to customers in the July 1, 2023 PGC filing totaled $145,938. After fully funding the Hardship Fund to the $750,000 cap, the additional residential portion flowed through to customers in the July 1, 2023 PGC filing totaled $25,462. The refund period for those amounts is July 2023 through June 2024. The penalty credits and supplier refund in the October 1, 2023 PGC filing totaling of $1,282,306 is being flowed through to residential and non-residential customers for the period of October 2023 through September 2024. The Company received a penalty credit in the amount of $4,067 in October 2023 and two penalty credits in the amounts of $485 and $510,386 in December 2023, which will be flowed through to customers through gas costs rates in a future PGC Filing.

IV. Prior Case Settlement Obligations

Q. Has the Company met settlement obligations from Docket No. R-2023-3038630?

A. Yes. Company Witness Pluard will address the obligation regarding reporting of penalties in excess of $100,000 for Operational Flow Order, overruns or other penalties at Columbia Statement No. 4. Company Witness Fischer will address the obligation regarding calculation of the quarterly gas supply charge in the manner identified by the Office of the Consumer Advocate, for informational purposes only, at Columbia Statement No. 2.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Supplement No. 379 to
Tariff Gas – Pa. P.U.C. No. 9

COLUMBIA GAS OF PENNSYLVANIA, INC.

121 Champion Way, Suite 100 **Canonsburg, Pennsylvania**

RATES AND RULES

FOR

FURNISHING GAS SERVICE

IN

THE TERRITORY AS DESCRIBED HEREIN

ISSUED: April 1, 2024 EFFECTIVE: October 1, 2024

ISSUED BY: MARK KEMPIC, PRESIDENT
121 CHAMPION WAY, SUITE 100
CANONSBURG, PENNSYLVANIA 15317

NOTICE

This Tariff Supplement Makes Changes to the Existing Tariff - See List of Changes Made by This Tariff Supplement on Pages No. 2 and 2a.

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
Cover	Tariff Cover Page	Supplement No., Issued and Effective Date.
2-2a	List of Changes	List of Changes.
16	Rate Summary	The "Gas Supply Charge" has increased. The "Gas Cost Adjustment" has increased. The "Pass-through Charge" has decreased. The "Total Effective Rate" for RSS increased. The "Total Effective Rate" for RDS decreased.
17	Rate Summary	The "Gas Supply Charge" has increased. The "Gas Cost Adjustment" has increased. The "Pass-through Charge" has decreased. The "Total Effective Rate" for SGSS increased. The "Total Effective Rate" for SCD and SGDS decreased.
18	Rate Summary	The "Gas Supply Charge" has increased. The "Gas Cost Adjustment" has increased. The "Pass-through Charge" has decreased. The "Total Effective Rate" has increased for LGSS.
19	Rate Summary	The "Gas Supply Charge" has increased. The "Gas Cost Adjustment" has increased. The "Pass-through Charge" has decreased. The "Total Effective Rate" has increased for MLSS.
20	Rate Summary	The Penalty Credit/Pipeline Refund Passback for "Residential" and "Non-Residential" has increased. The "Residential Price-to-Compare" and "Commercial Price-to-Compare" has increased. The "Rate SS – Standby Service" has decreased.
21	Rider Summary	The "Merchant Function Charge – Rider MFC" has increased.
21a	Gas Supply Charge Summary	The "PGCC" has increased. The "Rider MFC" has increased. The "Total Gas Supply Charge" has increased.

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
21b	Pass-through Charge Summary	The “PGDC” has decreased. The “PGDC E-Factor” has decreased. The “Capacity Assignment Factor” has increased. The “Pipeline Refund/Penalty Credits” has increased. The “Total Pass-through Charge” has decreased.
21c	Price-to-Compare Summary	The “PGCC” has increased. The “Gas Cost Adjustment” has increased. The “Capacity Assignment Factor” has decreased. The “Rider MFC” has increased. The “Total Price-to-Compare” has increased.
151	Rider PGC	The Purchased Gas Commodity Cost, made up of the Commodity Cost and the Commodity "E" Factor has increased. The Commodity Cost has increased. The Demand Cost has decreased. The Purchased Gas Demand Cost billed to Rate SGDS has decreased. The Purchased Gas Demand Cost billed to Rate RDS and Rate SCD has decreased. The Capacity Assignment Factor credited to Rate RDS and Rate SCD has increased.
154	Rider PGC	The Purchased Gas Demand Cost billed to Rate RDS and Rate SCD has decreased. The Capacity Assignment Factor credited to Rate RDS and Rate SCD has increased.

Supplement No. 379 to
Tariff Gas - Pa. P.U.C. No. 9
Two Hundred-fourth Revised Page No. 16
Columbia Gas of Pennsylvania, Inc.
Canceling Two Hundred-third Revised Page No. 16

Rate Summary

Rate per thm

Residential Rate Schedules		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-Through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Rider EE-Energy Efficiency Rider 5/	Total Effective Rate
Rate RSS - Residential Sales Service									
Customer Charge	$	16.75				(0.01)	0.00	-	16.74
Usage Charge	$	0.91069	0.24154	0.00121	0.28305	(0.00040)	0.00000	0.00304	1.43913
Rate RDS - Residential Distribution Service									
Customer Charge	$	16.75				(0.01)	0.00	-	16.74
Usage Charge:									
Customers Electing CHOICE	$	0.91069	-	-	0.25482	(0.00040)	0.00000	0.00304	1.16815

1/ Please see Page No. 21a for rate components.
2/ Please see Page No. 21b for rate components.
3/ The STAS percentage is reflected on Page No. 20 and is applied to the Customer Charge and the Distribution Charge.
4/ The DSIC percentage is reflected on Page No. 21 and is applied to the Customer Charge and the Distribution Charge.
5/ Rider EE is reflected on Page No. 21 and is applied to the Distribution Charge.

Issued: April 1, 2024 **Effective: October 1, 2024**

Mark Kempic - President

Supplement No. 379 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Twenty-seventh Revised Page No. 17
Columbia Gas of Pennsylvania, Inc. **Canceling One Hundred Twenty-sixth Revised Page No. 17**

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules <= 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Total Effective Rate	
Rate SGSS - Small General Sales Service									
Customer Charge:									
Annual Throughput <= 6,440 thm	$	29.92				(0.01)	0.00	29.91	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	57.00				(0.03)	0.00	56.97	
Usage Charge									
Annual Throughput <= 6,440 thm	$	0.69747	0.23912	0.00121	0.19115	(0.00031)	0.00000	1.12864	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.59489	0.23912	0.00121	0.19115	(0.00026)	0.00000	1.02611	
Rate SCD - Small Commercial Distribution									
Customer Charge:									
Annual Throughput <= 6,440 thm	$	29.92				(0.01)	0.00	29.91	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	57.00				(0.03)	0.00	56.97	
Usage Charge: Customers Electing CHOICE									
Annual Throughput <=6,440 thm	$	0.69747	-	-	0.16292	(0.00031)	0.00000	0.86008	
Annual Throughput >6,440 and <=64,400 thm	$	0.59489	-	-	0.16292	(0.00026)	0.00000	0.75755	
Rate SGDS - Small General Distribution Service									
Customer Charge:									
Annual Throughput <= 6,440 thm	$	29.92				(0.01)	0.00	29.91	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	57.00				(0.03)	0.00	56.97	
Usage Charge - Priority One									
Annual Throughput <= 6,440 thm	$	0.68756	-	-	0.19115	(0.00030)	0.00000	0.87841	5/
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.58497	-	-	0.19115	(0.00026)	0.00000	0.77586	5/
Usage Charge - Non-Priority One									
Annual Throughput <= 6,440 thm	$	0.68756	-	-	0.00010	(0.00030)	0.00000	0.68736	5/
Annual Throughput > 6,440 and <= 64,400 thm	$	0.58497	-	-	0.00010	(0.00026)	0.00000	0.58481	5/

1/ Please see Page No. 21a for rate components.
2/ Please see Page No. 21b for rate components.
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4/ The DSIC percentage is reflected on Page No. 21 and is applied to the Customer Charge and the Distribution Charge.
5/ Plus Rider EBS Option 1 or 2 - See Page 21.

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Mark Kempic - President

Supplement No. 379 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Sixty-first Revised Page No. 18
Columbia Gas of Pennsylvania, Inc.
Canceling One Hundred Sixtieth Revised Page No. 18

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules > 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Total Effective Rate	
Rate LGSS - Large General Sales Service									
Customer Charge:									
Annual Throughput > 64,400 thm and <= 110,000 thm	$	267.11				(0.12)	0.00	266.99	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	1,211.59				(0.53)	0.00	1,211.06	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	2,986.82				(1.31)	0.00	2,985.51	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	4,645.73				(2.04)	0.00	4,643.69	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	8,959.14				(3.94)	0.00	8,955.20	
Annual Throughput > 7,500,000 thm	$	13,272.55				(5.84)	0.00	13,266.71	
Usage Charge:									
Annual Throughput > 64,400 thm and <= 110,000 thm	$	0.45681	0.23812	0.00121	0.19105	(0.00020)	0.00000	0.88699	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	0.42709	0.23812	0.00121	0.19105	(0.00019)	0.00000	0.85728	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	0.23433	0.23812	0.00121	0.19105	(0.00010)	0.00000	0.66461	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	0.20785	0.23812	0.00121	0.19105	(0.00009)	0.00000	0.63814	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.18652	0.23812	0.00121	0.19105	(0.00008)	0.00000	0.61682	
Annual Throughput > 7,500,000 thm	$	0.11099	0.23812	0.00121	0.19105	(0.00005)	0.00000	0.54132	
Rate SDS - Small Distribution Service									
Customer Charge:									
Annual Throughput > 64,400 thm and <= 110,000 thm	$	267.11				(0.12)	0.00	266.99	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	1,211.59				(0.53)	0.00	1,211.06	
Usage Charge:									
Annual Throughput > 64,400 thm and <= 110,000 thm	$	0.45681	-	-	-	(0.00020)	0.00000	0.45661	5/
Annual Throughput > 110,000 thm and <= 540,000 thm	$	0.42709	-	-	-	(0.00019)	0.00000	0.42690	5/
Rate LDS - Large Distribution Service									
Customer Charge:									
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	2,986.82				(1.31)	0.00	2,985.51	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	4,645.73				(2.04)	0.00	4,643.69	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	8,959.14				(3.94)	0.00	8,955.20	
Annual Throughput > 7,500,000 thm	$	13,272.55				(5.84)	0.00	13,266.71	
Usage Charge:									
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	0.23433	-	-	-	(0.00010)	0.00000	0.23423	5/
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	0.20785	-	-	-	(0.00009)	0.00000	0.20776	5/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.18652	-	-	-	(0.00008)	0.00000	0.18644	5/
Annual Throughput > 7,500,000 thm	$	0.11099	-	-	-	(0.00005)	0.00000	0.11094	5/

1/ Please see Page No. 21a for rate components.
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4/ The DSIC percentage is reflected on Page No. 21 and is applied to the Customer Charge and the Distribution Charge.
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Mark Kempic - President

Supplement No. 379 to
Tariff Gas - Pa. P.U.C. No. 9
Ninetieth Revised Page No. 19
Columbia Gas of Pennsylvania, Inc. **Canceling Eighty-ninth Revised Page No. 19**

Rate Summary

Rate per thm

Main Line Service Rate Schedules Commercial / Industrial		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Total Effective Rate	
Rate MLSS - Main Line Sales Service									
Customer Charge:									
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34				(0.21)	0.00	469.13	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00				(0.51)	0.00	1,148.49	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00				(0.90)	0.00	2,049.10	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00				(1.80)	0.00	4,094.20	
Annual Throughput > 7,500,000 thm	$	7,322.00				(3.22)	0.00	7,318.78	
Usage Charge:									
MLS Class I Annual Throughput > 274,000 thm	$	0.00937	0.23812	0.00121	0.19105	0.00000	0.00000	0.43975	
MLS Class II:									
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04481	0.23812	0.00121	0.19105	(0.00002)	0.00000	0.47517	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03876	0.23812	0.00121	0.19105	(0.00002)	0.00000	0.46912	
Annual Throughput > 7,500,000 thm	$	0.03355	0.23812	0.00121	0.19105	(0.00001)	0.00000	0.46392	
Rate MLDS - Main Line Distribution Service									
Customer Charge:									
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34				(0.21)	0.00	469.13	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00				(0.51)	0.00	1,148.49	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00				(0.90)	0.00	2,049.10	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00				(1.80)	0.00	4,094.20	
Annual Throughput > 7,500,000 thm	$	7,322.00				(3.22)	0.00	7,318.78	
Usage Charge:									
MLS Class I Annual Throughput > 274,000 thm	$	0.00937	-	-	-	0.00000	0.00000	0.00937	5/
MLS Class II:									
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04481	-	-	-	(0.00002)	0.00000	0.04479	5/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03876	-	-	-	(0.00002)	0.00000	0.03874	5/
Annual Throughput > 7,500,000 thm	$	0.03355	-	-	-	(0.00001)	0.00000	0.03354	5/

1/ Please see Page No. 21a for rate components.
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Mark Kempic - President

Supplement No. 379 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Forty-fifth Revised Page No. 20
Canceling One Hundred Forty-fourth Revised Page No. 20

Columbia Gas of Pennsylvania, Inc.

Other Rates Summary

Rate per thm

Description		Rate $/ thm		Applicable Rate Schedules
Penalty Credit/Pipeline Refund Passback - Residential		(0.00472)	1/	RSS/RDS/CAP
Penalty Credit/Pipeline Refund Passback - Non-Residential	$	(0.00102)	2/	SGSS/SGDS-P1/SCD/LGSS/MLSS
Price to Compare for Residential Gas Supply	$	0.27098	3/	RSS
Price to Compare for Commercial Gas Supply	$	0.26856	3/	SGSS (< = 64,400 thms)
State Tax Adjustment Surcharge Percentage		(0.044%)		Customer and Distribution Charges on all rates
Rate SS - Standby Service	$	1.10601		Per therm based on a customer's Maximum Daily Firm Requirement. See Pages 134 - 136 herein for detail.

1/ Penalty Credit and Pipeline Refund passback rate effective January 2024-December 2024.
2/ Penalty Credit and Pipeline Refund passback rate effective January 2024-December 2024.
3/ Please see Page No. 21c for rate components.

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Mark Kempic - President

Supplement No. 379 to
Tariff Gas - Pa. P.U.C. No. 9
Two Hundred Twenty-first Revised Page No. 21
Columbia Gas of Pennsylvania, Inc. **Canceling Two Hundred Twentieth Revised Page No. 21**

Rider Summary

Riders	Rate			Applicable Rate Schedules
Customer Choice - Rider CC	$	0.00010	/thm	RSS/RDS/SGSS/SGDS/SCD/DGDS
Universal Service Plan - Rider USP	$	0.09560	/thm	RSS/RDS
Distribution System Improvement Charge - Rider DSIC		0.00%		This percentage is applied to the Distribution Charge and the Customer Charge. See Pages 177-180a for Rider DSIC details.
Elective Balancing Service - Rider EBS:				
Option 1 - Small Customer	$	0.01553	/thm	SGDS/SDS
Option 1 - Large Customer	$	0.00810	/thm	LDS/MLDS
Option 2 - Small Customer	$	0.00697	/thm	SGDS/SDS
Option 2 - Large Customer	$	0.00226	/thm	LDS/MLDS
Gas Procurement Charge - Rider GPC	$	0.00113	/thm	RSS/SGSS/LGSS/MLSS
Merchant Function Charge - Rider MFC	$	0.00342	/thm	RSS
Merchant Function Charge - Rider MFC	$	0.00100	/thm	SGSS
Purchased Gas Cost - Rider PGC		Pg. 21a & 21b		Rate Schedules specified on Page 21a & 21b
Energy Efficiency Rider	$	0.00304	/thm	RSS/RDS
State Tax Adjustment Surcharge Percentage		(0.044%)		Customer and Distribution Charges on all rates

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Mark Kempic - President

Supplement No. 379 to
Tariff Gas - Pa. P.U.C. No. 9
Sixty-fifth Revised Page No. 21a
Columbia Gas of Pennsylvania, Inc. **Canceling Sixty-fourth Revised Page No. 21a**

Gas Supply Charge Summary

Rate per thm

Rate Schedule		PGCC	Rider GPC	Rider MFC	Total Gas Supply Charge
Rate CAP - Customer Assistance Plan	$	0.23699	0.00113	0.00342	0.24154
Rate RSS - Residential Sales Service	$	0.23699	0.00113	0.00342	0.24154
Rate SGSS - Small General Sales Service	$	0.23699	0.00113	0.00100	0.23912
Rate LGSS - Large General Sales Service	$	0.23699	0.00113	-	0.23812
Rate MLSS - Main Line Sales Service	$	0.23699	0.00113	-	0.23812

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Mark Kempic - President

Supplement No. 379 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Ninth Revised Page No. 21b
Canceling One Hundred Eighth Revised Page No. 21b

Columbia Gas of Pennsylvania, Inc.

Pass-through Charge Summary

Rate per thm

Rate Schedule		PGDC	PGDC "E" Factor	Capacity Assignment Factor	Pipeline Refund/ Penalty Credits	Rider CC	Rider USP	Total Pass-through
Rate CAP - Customer Assistance Plan	$	0.18457	0.00750	-	(0.00472)	-	-	0.18735
Rate RSS - Residential Sales Service	$	0.18457	0.00750	-	(0.00472)	0.00010	0.09560	0.28305
Rate SGSS - Small General Sales Service	$	0.18457	0.00750	-	(0.00102)	0.00010	-	0.19115
Rate LGSS - Large General Sales Service	$	0.18457	0.00750	-	(0.00102)	-	-	0.19105
Rate MLSS - Main Line Sales Service	$	0.18457	0.00750	-	(0.00102)	-	-	0.19105
Rate RDS - Residential Distribution Service	$	0.18457	0.00750	(0.02823)	(0.00472)	0.00010	0.09560	0.25482
Rate SCD - Small Commercial Distribution (Choice)	$	0.18457	0.00750	(0.02823)	(0.00102)	0.00010	-	0.16292
Rate SGDS - Small General Distribution Service								
Priority One (P1)	$	0.18457	0.00750	-	(0.00102)	0.00010	-	0.19115
Non-Priority One (NP1)		-	-	-	-	0.00010	-	0.00010
Rate SDS - Small Distribution Service	$	-	-	-	-	-	-	-
Rate LDS - Large Distribution Service	$	-	-	-	-	-	-	-
Rate MLDS - Main Line Distribution Service	$	-	-	-	-	-	-	-

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Mark Kempic - President

Supplement No. 379 to
Tariff Gas - Pa. P.U.C. No. 9
Sixty-fifth Revised Page No. 21c
Columbia Gas of Pennsylvania, Inc. **Canceling Sixty-fourth Revised Page No. 21c**

Price-to-Compare (PTC) Summary
Rate per thm

Customer Class	PGCC	Gas Cost Adjustment	Capacity Assignment Factor	Rider GPC	Rider MFC	Total Price-to-Compare
Residential	$ 0.23699	0.00121	0.02823	0.00113	0.00342	0.27098
Commercial < = 64,400 thm/year	$ 0.23699	0.00121	0.02823	0.00113	0.00100	0.26856

Issued: April 1, 2024 **Effective: October 1, 2024**

Mark Kempic - President

RIDER PGC - PURCHASED GAS COST

PROVISIONS FOR RECOVERY OF PURCHASED GAS COSTS

RIDER PGC APPLICABLE TO SALES SERVICE CUSTOMERS

Rates for each thm of gas supplied to sales customers subject to this Rider under the Rate RSS, Rate SGSS, Rate LGSS, and Rate MLSS rate schedules shall include $0.43027 per thm for recovery of purchased gas costs. (I)(D) This rate includes the commodity cost component (CC) of $0.23699 per thm, the commodity "E" Factor component (CE) of $0.00121 per thm, the demand cost component (DC) of $0.18457 per thm, and the demand "E" Factor component of $0.00750 per thm.

RIDER PGC APPLICABLE TO SGDS PRIORITY ONE CUSTOMERS

Rates for each thm of gas distributed under the Rate SGDS rate schedules for Priority-One Service customers (D) shall include $0.17707 per thm for recovery of Purchased Gas Demand Costs (PGDC). This rate includes the DC of $0.18457 per thm and the demand "E" Factor component of $0.00750 per thm.

RIDER PGC CHARGED TO CHOICE DISTRIBUTION SERVICE CUSTOMERS

Rates for each thm of gas distributed under Rate RDS and Rate SCD shall include $0.16384 per thm for recovery of Purchased Gas Demand Costs. This rate includes the DC of $0.18457 per thm, the Capacity Assignment (D)(I) Factor (CAF) of ($0.02823) per thm and the DC "E" Factor component of $0.00750 per thm. The CAF represents costs not assignable to Choice Distribution Service customers.

Such rates shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's Regulations, to reflect changes in the level of purchased gas costs, as calculated in the manner set forth below.

PRESENTATION ON CUSTOMER BILLS

For sales service customers served under Rate RSS, Rate SGSS, Rate LGSS and Rate MLSS, the Pass-through Charge includes the PGDC of $0.18457 per thm plus the demand "E" Factor of $0.00750 per thm. The two factors (D)(I) total $0.19207 per thm. The Gas Supply Charge includes the PGCC of $0.23699 per thm. The Gas Cost Adjustment is the commodity "E" Factor of $0.00121 per thm.

For General Distribution Service customers served under Priority-One Rate SGDS, the Pass-through Charge includes the PGDC of $0.18457 per thm and the demand "E" Factor component of $0.00750 per thm, totaling (D) $0.19207 per thm.

For Choice Distribution Service customers served under Rate RDS or Rate SCD, the Pass-through Charge includes the PGDC of $0.18457 per thm, the CAF of ($0.02823) per thm and the demand "E" Factor component (I)(D) of $0.00750 per thm, all of which total $0.16384 per thm.

QUARTERLY UPDATES

The Company's rates for recovery of purchased gas costs are also subject to quarterly adjustments under procedures set forth in the Commission's regulations at 52.Pa. Code § 53.64 (i) (5). Such updates shall reflect, in addition to the provisions of the regulation, adjustments to the projected commodity cost of purchased gas based upon more current versions of the same sources of data and using the same methods to project the commodity cost of purchased gas approved by the Commission in the Company's most recent annual proceeding for recovery of purchased gas costs under section 1307(f) of the Public Utility Code.

(D) Indicates Decrease (I) Indicates Increase

RIDER PGC - PURCHASED GAS COST (Continued)

COMPUTATION OF PURCHASED GAS DEMAND COSTS PER THM – Continued

Supplier Refunds and Pipeline Penalty Credits that are not included in "CE" will be included in the calculation of "DE". Supplier Refunds and Pipeline Penalty Credits will include interest added at the annual rate of six percent (6%) calculated from the month received to the effective month such refund is refunded. The period over which such refunds will be made shall be established by the Commission.

> "S" - projected thms of gas to be billed to customers under the distribution charges of the Rate RSS, Rate SGSS, Rate LGSS, and Rate MLSS rate schedules plus the projected thm of gas to be distributed to customers under Rate RDS, Rate SCD and SGDS Priority One Distribution rate schedules of this Tariff during the period when rates will be in effect.

The portion of Supplier Refunds and Penalty Credits that would otherwise be credited to residential customers shall be credited to the Hardship Fund (mentioned in the USP Rider section of this tariff) when the balance of the Hardship Fund falls below $750,000. The non-residential portion of Supplier Refunds and Penalty Credits will be credited to applicable non-residential customers through the PGC. When the Hardship Fund balance is $750,000 or more, and Pipeline Supplier Refunds and Pipeline Penalty Credits received by the Company will be included in the calculation of the PGDC as specified above.

PROVISION OF PURCHASED GAS DEMAND COST CREDIT DUE TO CUSTOMERS ELECTING CHOICE DISTRIBUTION SERVICE – CAPACITY ASSIGNMENT FACTOR (CAF)

The Purchased Gas Demand Cost (PGDC) rate included in the Pass-through Charge billed to Choice Distribution Service customers served under Rate RDS or Rate SCD shall be $0.15634 per thm. Such rate shall be equal to the PGDC component of $0.18457 per thm as calculated above, less the CAF of $0.02823 (D)
per thm. The CAF shall be equal to the projected annual cost of assigned Firm Capacity less estimated annual storage commodity costs (storage injection, withdrawal, shrinkage and commodity transportation cost) with the net divided by the estimated, normalized annual usage of customers electing Choice Distribution Service. The CAF of $0.02823 per thm representing costs not assignable to CHOICE customers shall be included in the Price-to-Compare.

DETERMINATION OF OVER/UNDERCOLLECTION OF GAS COSTS

Commodity E-factor

In computing the experienced over/under collection of purchased gas commodity costs for a period defined by the Commission, the following procedure shall be used:

(a) All experienced purchased gas commodity costs actually incurred by the Company to service customers pursuant to all rate schedules of this Tariff.

Experienced purchased gas commodity costs shall include, but not be limited to, the following:

(1) payments to suppliers to accept assignment of capacity on interstate pipelines other than Columbia Gas Transmission, LLC to the extent permitted under the Rules Applicable to Distribution Service;

(2) costs paid for employing futures, options and other risk management tools, including but not limited to, supplier related costs associated with the fixed price contracts or financial contracts utilized by the Company to lessen the impact of price volatility for PGC customers; and

(3) the index price of gas purchased from distribution customers under the provisions of the Deliveries in Excess of Consumption section of Paragraph 3 of the Rules Applicable to Distribution Service.

(D) Indicates Decrease (I) Indicates Increase

COLUMBIA STATEMENT NO. 4

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
v.	)	Docket No. R-2024-3047014
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF

PATRICK J. PLUARD

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2024

Q. Please state your name, business address and title.

A. My name is Patrick J. Pluard. My business address is 1500 165th Street, Hammond, Indiana 46324. I am the Director of Portfolio Optimization in the Energy Supply and Trading Department for Northern Indiana Public Service Co. ("NIPSCO").

Q. Please describe your educational and employment background.

A. I attended Purdue University where I graduated with a Bachelor of Science in Marketing in 1994 and a Master's in Business Administration in 2000. I began my employment with NiSource Inc. in 2004 as a Real Time Energy Trader. In 2008, I transferred to operations as a Generation System Supervisor. In 2011, I was promoted to Manager of Day Ahead Asset Optimization. I was promoted to my current role, Director of Portfolio Optimization, in March of 2013.

Q. What are your responsibilities as Director of Portfolio Optimization?

A. As Director of Portfolio Optimization, I am responsible for a team consisting of system operators, engineers and gas portfolio managers that manage gas and electric assets for NiSource subsidiaries. Specific to this filing, my team is responsible for meeting the daily needs of Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or the "Company") customers through procurement of natural gas utilizing transportation and storage portfolio assets in a safe and reliable manner at the lowest reasonable cost.

Q. Have you previously testified before the Pennsylvania Public Utility Commission ("Commission")?

A. Yes. I was a rebuttal witness in the Company's 2022 1307(f) proceeding at Docket

No. R-2022-3031172 and a witness in the 2023 1307(f) proceeding at Docket No. R-2023-3038630.

Q. Have you previously testified before any other state utility commission?

A. Yes, I have testified for NIPSCO before the Indiana Utility Regulatory Commission as a Gas Cost Accounting and Green Power Rider witness. I have also testified for Columbia Gas of Kentucky's Price Based Rates mechanism renewal request.

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

A. The purpose of my testimony is to: (1) explain Columbia's gas purchasing and procurement strategies to acquire the least cost reliable gas supplies to serve its customers; (2) discuss Columbia's successful Unified Sharing Mechanism ("USM") for sharing net proceeds from capacity releases and off-system sales; and (3) provide an update on the financial hedging program approved in the 2023 1307(f).

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits, which were included with Columbia's pre-filing data submitted on March 1, 2024:

Table 1.

Number	Description	Regulation
Company Exhibit 1-D-1	**Detail of Contracts and Negotiations**	**53.64(c)(1)**
Company Exhibit 1-D-2	**Detail of Take-or-Pay and Minimum Bill Provisions**	**53.64(c)(1)**
Company Exhibit 1-D-3	**List of Maximum Daily Quantity Levels and Maximum Annual Quantity Levels**	**53.64(c)(1)**
Company Exhibit 6	**List of Off-System Sales**	**53.64(c)(7)**
Company Exhibit 8-A	**Cost of Affiliated Gas as Compared to the Average Market Price of Other Pipeline Suppliers and Other Sources**	**53.65(1)**
Company Exhibit 8-B	**Estimates of the Quantity of Gas Available to the Company from All Sources**	**53.65(2)**
Company Exhibit 8-C	**Efforts Made by the Company to Obtain Gas Supply from Non-affiliated Interests**	**53.65(3)**
Company Exhibit 8-D	**Demonstration that Purchases from an Affiliated Interest are Consistent with a Least Cost Procurement Policy**	**53.65(4)**
Company Exhibit 8-E	**Source and Amount of All Supplies Withheld from the Market by the Company or its Affiliates**	**53.65(5)**

I. COLUMBIA'S SUPPLY AND CAPACITY PROCUREMENT

Q. What are Columbia's gas purchasing objectives and strategies?

A. Columbia has a least cost objective to secure and deliver competitively priced, reliable gas supplies for its customers. Columbia is sensitive to the impact of gas costs upon its customers and balances this concern with its utility obligation to provide reliable gas supplies to its firm customers whenever they want gas service under a wide range of weather conditions.

Columbia's gas purchasing strategy is to contract for a portfolio of gas supplies and capacity that has the flexibility both to meet reliability standards and be able to take advantage of low-price opportunities when available and operationally feasible.

Q. What are Columbia's gas procurement policies?

A. Columbia contracts for sufficient firm gas supplies to serve, at a minimum, the demand of its firm service customers under design weather conditions, both design day and seasonal. Firm gas supplies include storage supplies, purchases under firm gas supply contracts and firm monthly and daily gas supply purchases, delivered through firm transportation capacity and local gas supplies on a seasonal basis. Firm gas supply contracts can include both long-term and short-term contracts that provide the supplier with an incentive to deliver supplies with a high degree of reliability on a daily and seasonal basis.

In contracting for firm gas supplies, Columbia purchases firm gas supplies during the winter months to assure sufficient gas supplies are available in the event Columbia experiences colder than normal daily temperatures. Columbia purchases firm supplies to provide flexibility in recognition of annual fluctuations in seasonal and daily demand and minimize gas costs for its customers.

Q. Please address Columbia's segmentation of its gas supply contracts.

A. Columbia's contracts are presently segmented into two categories: short-term and spot market. Columbia defines short-term contracts as firm gas purchase agreements with a contract length of one year or less. Spot market contracts are gas purchases made at the time of need for between one day and one month in length.

Q. How does Columbia determine prices under these contracts?

A. Prices under firm short-term contracts are typically based upon a nationally published index plus a small premium. The index and premium are established as a result of the request for proposal ("RFP") and contract negotiation process. Spot market contract prices are based on market conditions negotiated at the time of purchase.

Q. Please explain the premium Columbia pays under its firm purchase contracts that it enters into on a short-term basis.

A. Columbia negotiates a nominal premium with suppliers for purchases under its short-term gas purchase agreements to assure Columbia and its customers of sufficient firm, reliable gas supplies at competitive prices, under widely varying weather and market conditions.

Q. Please describe the process Columbia follows to acquire short-term firm supplies over a period in excess of one month.

A. Annually, Columbia submits an RFP to numerous suppliers identified as capable and willing to provide firm gas supplies to Columbia. Columbia requests proposals for supplies with varying term lengths, nomination flexibility and innovative pricing options. Upon receipt of proposals submitted in response to the RFP, Columbia evaluates the responses and begins negotiations with suppliers whose proposals provide the required supply assurances at the least cost. Negotiations continue until satisfactory agreements are reached or until an impasse is reached, after which another supplier negotiation is initiated.

Q. What were the results of your most recent RFP cycle?

A. For the 2023-2024 winter, Columbia entered into ten new term gas purchase agreements.

Q. Does Columbia purchase spot market gas supplies in volumes exceeding its Firm Transportation Service ("FTS") contract level during the summer months?

A. Yes. In order for Columbia to inject sufficient gas supplies into its storage accounts, particularly its Firm Storage Service account with Columbia Gas Transmission, LLC ("TCO"), to meet winter season customer demand, it must purchase gas supplies in volumes exceeding its FTS capacity during the summer. These additional gas purchases are made under spot market contracts and delivered to its storage accounts using Columbia's Storage Service Transportation capacity at secondary receipt and delivery points.

Q. Did Columbia seek out RFP bids for the provision of firm service natural gas supplies to Texas Eastern Transmission, LP ("TETCO") Zone M-3 delivery points at Texas Eastern M-2 Zone index prices?

A. Yes, Columbia's 2023-2024 winter TETCO RFP included a pricing option for bids for the provision of firm natural gas supplies delivered to TETCO Zone M-3 points at TETCO M-2 Zone index prices. Bids were received and reviewed, and based on the review, Columbia did award an AMA.

Q. What are Columbia's projected gas sales for the 12 months ending September 30, 2024, which is the application period for gas costs under § 1307(f) of the Public Utility Code?

A. As shown in Company Exhibit 1-A, Schedule 1, Sheet 1, line 4, Columbia's projected sales for the 12 months ending September 30, 2024, total 396,376,468 therms.

Q. Does this amount include sales by Natural Gas Suppliers under Columbia's Customer CHOICE℠ program?

A. No, only projected sales by Columbia are included in Company Exhibit 1-A, Schedule 1, Sheet 1, line 4.

Q. Does Columbia purchase supply from Pennsylvania production?

A. Yes, Columbia maintains a program for purchasing local Pennsylvania production. A portion of the local production is delivered directly into Columbia's distribution system. Columbia purchases a second portion at TCO's Appalachian receipt points. Purchases made with Appalachian receipt point transportation capacity are often made at pools or aggregation points, where volumes of local gas become commingled with gas supplies from other sources. Therefore, it becomes impossible to determine how much of those supplies are produced in Pennsylvania.

Q. Did Columbia exceed $100,000.00 in Operational Flow Order, overrun or other penalties during the PGC year (February 2023 – January 2024)?

A. No, Columbia had a total of approximately $406 of overrun charges during this period.

II. UNIFIED SHARING MECHANISM ("USM")

Q. Columbia manages its off-system sales and capacity release programs under its USM. Please explain.

A. A market exists for Natural Gas Distribution Companies, such as Columbia, to market unbundled and re-bundled gas and capacity products to non-traditional customers. Columbia's off-system sales and capacity release programs provide Columbia and its customers an opportunity to benefit from the unbundling of interstate pipeline services implemented by FERC Order 636. Columbia's off-system sales incentives began in January 1995 and capacity release incentives began in February 1996. In the Company's 2009 Section 1307(f) proceeding (Docket No. R-2009-2093219), the Commission approved a revision to the unified off-system sales and capacity release sharing mechanisms commencing October 1, 2009, and operating for a three-year period. The unified sharing mechanism established by the Commission's Order in Columbia's 2009 1307(f) proceeding was revised so that customers will receive 75% of the net USM proceeds while Columbia receives the remaining 25% of the incentive. In the Company's 2012 Section 1307(f) proceeding (Docket No. R-2012-2293303), the Commission approved the parties' agreement that Columbia's current 75% customer 25% Company USM shall continue indefinitely, absent Commission directive to the contrary. This order provided that in future proceedings parties may propose changes to the USM in their direct testimony. As a result of the Commission's Order in the 2013 1307(f) case, slight modifications were made to the USM calculation with respect to the methodology utilized to apply applicable credits; however, all other aspects of the USM remained unchanged. As a result of the Commission's Order in the 2014 1307(f) case, Columbia performed an evaluation in its 2015 1307(f) pre-filing of whether the existing allocation of the customers' share of USM credits between the Purchased Gas Commodity Cost ("PGCC") and the Purchased Gas Demand Cost ("PGDC") within the PGC should be modified. The Commission, in its Order in the 2015 1307(f) proceeding, directed that the pass back of the customers' share of USM credits be made 100% through the PGDC. Columbia implemented this methodology effective with its October 1, 2015 PGC compliance filing.

Q. What have been the historical results of Columbia's USM?

A. Table 2 below lists the historic total off-system sales margins and capacity release revenues, as well as the Company and customer shares and percentages. Actual data is provided for prior USM program sharing mechanisms through the year ending September 30, 2022. Data for the current USM program year ending September 30, 2023, includes actual booked margins through February 2022 and estimated incremental revenue from March 2022 through September 30, 2024.

Table 2.

Historic and Projected Unified Sharing Mechanism Customer and Company Share

Historic Period	USM Total Margin ($)	Customer Share ($)	Customer Share (%)	Company Share ($)	Company Share (%)
Oct 2002 – Sept 2003	$17,424,586	$8,556,146	46.10%	$8,868,440	50.90%
Oct 2003 – Sept 2004	$15,256,111	$8,539,028	55.97%	$6,717,083	44.03%
Oct 2004 – Sept 2005	$15,112,450	$10,556,225	69.85%	$4,556,225	30.15%
Oct 2005 – Sept 2006	$13,914,577	$9,957,288	71.56%	$3,957,289	28.44%
Oct 2006 – Sept 2007	$19,309,539	$13,691,677	70.91%	$5,617,862	29.09%
Oct 2007 – Sept 2008	$14,383,502	$10,243,451	71.22%	$4,140,051	28.78%
Oct 2008 – Sept 2009	$11,152,477	$8,106,734	72.69%	$3,045,743	27.31%
Oct 2009 – Sept 2010	$11,851,708	$8,888,781	75%	$2,962,927	25%
Oct 2010 – Sept 2011	$10,312,511	$7,734,383	75%	$2,578,128	25%
Oct 2011 – Sept 2012	$5,597,628	$4,198,221	75%	$1,399,407	25%
Oct 2012 – Sept 2013	$7,479,592	$5,609,694	75%	$1,869,898	25%
Oct 2013 – Sept 2014	$15,950,716	$11,963,037	75%	$3,987,679	25%
Oct 2014 – Sept 2015	$12,124,848	$9,093,636	75%	$3,031,212	25%
Oct 2015 – Sept 2016	$12,278,866	$9,209,149	75%	$3,069,717	25%
Oct 2016 – Sept 2017	$10,052,000	$7,540,000	75%	$2,512,000	25%
Oct 2017 – Sept 2018	$6,728,427	$5,046,320	75%	$1,682,107	25%
Oct 2018 – Sept 2019	$4,231,608	$3,173,706	75%	$1,057902	25%
Oct 2019 – Sept 2020	$1,813,318	$1,359,989	75%	$453,329	25%
Oct 2020 – Sept 2021	$2,370,807	$1,778,106	75%	$592,702	25%
Oct 2021 – Sept 2022	$2,375,976	$1,781,982	75%	$593,994	25%
Oct 2022 – Sep 2023	$4,470,583	$3,352,937	75%	$1,117,646	25%
Oct 2023 – Sept 2024 (est.)	$2,826,879	$2,120,159	75%	$706,720	25%

III. FINANCIAL HEDGING PROGRAM

Q. Per the Commission-approved Settlement of Columbia's 2023 1307(f) proceeding, did Columbia execute the financial hedges according to the agreed upon program?

A. Yes. Consistent with the 2023 1307(f) settlement at R-2023-3038630, Columbia executed the following financial hedges.

Table: 3 – Financial Hedge Summary

Days	Month	Vol/Month	Vol/Day	Price	Purch. Value	
30	Apr-24	660,000	22,000	$ 2.545	$ 1,679,700	Summer '24 *executed* 12/19/23
31	May-24	660,000	21,290	$ 2.545	$ 1,679,700	JPMorgan
30	Jun-24	660,000	22,000	$ 2.545	$ 1,679,700	
31	Jul-24	660,000	21,290	$ 2.545	$ 1,679,700	
31	Aug-24	660,000	21,290	$ 2.545	$ 1,679,700	
30	Sep-24	660,000	22,000	$ 2.545	$ 1,679,700	
31	Oct-24	660,000	21,290	$ 2.545	$ 1,679,700	
30	Nov-24	670,000	22,333	$ 3.584	$ 2,401,280	Winter '24'25 *to be executed* 1/24/24
31	Dec-24	670,000	21,613	$ 3.584	$ 2,401,280	JPMorgan
31	Jan-25	670,000	21,613	$ 3.584	$ 2,401,280	
28	Feb-25	670,000	23,929	$ 3.584	$ 2,401,280	
31	Mar-25	670,000	21,613	$ 3.584	$ 2,401,280	
30	Apr-25	670,000	22,333	$ 3.120	$ 2,090,400	Summer'25 *executed* 2/16/24
31	May-25	670,000	21,613	$ 3.120	$ 2,090,400	J. Aron (Goldman Sachs)
30	Jun-25	670,000	22,333	$ 3.120	$ 2,090,400	
31	Jul-25	670,000	21,613	$ 3.120	$ 2,090,400	
31	Aug-25	670,000	21,613	$ 3.120	$ 2,090,400	
30	Sep-25	670,000	22,333	$ 3.120	$ 2,090,400	
31	Oct-25	670,000	21,613	$ 3.120	$ 2,090,400	
30	Nov-25	660,000	22,000	$ 4.090	$ 2,699,400	Winter '25'26 *executed* 3/15/24
31	Dec-25	660,000	21,290	$ 4.090	$ 2,699,400	
31	Jan-26	660,000	21,290	$ 4.090	$ 2,699,400	
28	Feb-26	660,000	23,571	$ 4.090	$ 2,699,400	
31	Mar-26	660,000	21,290	$ 4.090	$ 2,699,400	

Q. Can you provide an example of how this is going to work on a monthly basis?

A. Yes. The product is known as a "fixed to float," whereby the price is fixed upon execution and settles out monthly at the NYMEX Henry Hub futures expiration price. For example, when Columbia fixed the April 2024 financial contract at

$2.55, the market floats between now and April 2024. Upon the expiration of the April 2024 contract in March of 2024, the difference between the expiration price and fixed price is exchanged between Columbia and the supplier. Assuming the April 2024 contract expires at $2.60, the supplier would pay Columbia the difference of $.05. The funds would flow through to the PGC customers creating a netting effect of locking in a $.05 gain against the $2.60 physical April purchase, fixing the April price to the customer at $2.55.

VI. Certified Natural Gas

Q. Did Columbia purchase Certified Natural Gas during the applicable review period?

A. No. While Columbia did not purchase any certified natural gas or related certificates, Columbia continues to gather insight, develop relationships and is working to develop a position on this issue. Columbia, being part of NiSource, is in contact with various certifying agencies, is a member of a certified natural gas coalition, and has officially joined the MIQ registry, which will enable Columbia to certify a portion of its supply when appropriate. Columbia will continue to monitor this industry initiative and provide updates as it progresses.

Q. Does this conclude your direct testimony?

A. Yes, it does.