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File #: 210103

April 1, 2025

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, *et al.* v. Columbia Gas of Pennsylvania, Inc.
Docket Nos. R-2025-3053663, *et al.*

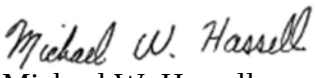
Dear Secretary Chiavetta:

Enclosed for filing on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia") is Supplement No. 398 to Tariff Gas of Pa. PUC No. 9 ("Supplement No. 398"), issued April 1, 2025, with a proposed effective date of October 1, 2025. Supplement No. 398 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. 398 proposes an increase in gas cost recovery rates of $0.20855 /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 September 2026, which is attached as Revised Exhibit 1-A, Schedule 2, to Statement No. 2. Columbia also notes that revised Exhibits 1-A, 1-B, 1-3-1 Attachments 1, 5, and 15 are also included with the filing, with the revisions explained in the corresponding testimony.

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

Respectfully submitted,



Michael W. Hassell

MWH/dmc
Attachments

cc: The Honorable Emily I. DeVoe (*via email; w/attachments*)
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).

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Date: April 1, 2025

Michael W. Hassell

Michael W. Hassell

COLUMBIA STATEMENT NO. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2025-3053663
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
TINA M. MONNIG

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2025

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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, 2023, 2024 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 February 28, 2025:

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 2025-26, 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.

Q. **Are there any updates to the exhibits you are sponsoring?**

A. Yes, Revised Exhibit 5 and Revised Exhibit 15 are submitted with this testimony to replace original Exhibits 5 and 15 submitted in the 1307(f) pre-filing on February 28, 2025.

Q. **Why are Revised Exhibits being submitted?**

A. Following the preparation of the pre-filing, it was determined that the 3-year contract with a large industrial customer ending October 31, 2025, for 5,215 Dth of non-recallable capacity release with TCO will not be renewed by the customer. This release was included in Exhibit 5, Table 4 and impacted the results of the 103% policy in Exhibit 15. The details of this impact will be addressed later in this testimony.

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 small commercial customers is derived by forecasting customer count and gas use per customer. The customer count is derived using economic and demographic data (households, real income per capita). The use per customer is derived using weather data throughout Columbia's operations territory and energy intensity. The large commercial customer forecast is developed by the Large Customer Relations group by incorporating information generated through individual customer interviews. 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 Revised 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 on 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 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 2025-26, 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[SM] 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-1, TCO delivers about 79 percent of Columbia's design day

supply. As such, Columbia must continue to rely upon its 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 November through March, 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/day from November through March of each year, and 2,000 Dth/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.

Last, 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/day including up to 19,130 Dth from storage. Summer capacity levels are sculpted with 32,000 Dth/day in April and October and 20,000 Dth/day May through September.

Columbia utilizes the Equitrans storage service, approximately 9,384 Dth/day of the associated 19,130 Dth/day of the winter season FTS Transportation Quantity ("TQ"), and the EGTS storage service (3,139 Dth/day) of 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 25,635 Dth/day. A total of 22,553 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 22,553 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 Columbia

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 Columbia 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. The Company acquired the following contract: 9,300 Dth firm transportation on TGP with a one winter only term of November 1, 2024, through March 31, 2025.
In addition, Columbia renewed its TCO FSS contract in the amount of 21,948,692 Dth and a TCO SST contract in the amount of 395,714 Dth, which were set to expire on March 31, 2025. This renewal extends the contract for another five years.

Q. Why did Columbia enter into the TGP firm transportation contract for 9,300 Dth?

A. As discussed in Revised Exhibit 5, Sheet 12, Columbia entered into a new contract to address market needs. Specifically, the 9,300 Dth on TGP was to serve the Warrendale area. This was needed to meet design day requirements in this area.

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 six to nine 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) 14,935 Dth of firm transportation on Texas Eastern; and

2) 4,304 Dth of firm transportation capacity on National Fuel.

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 14,935 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.

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. For reasons I will address later in my testimony Columbia's portfolio is outside the 103% policy. A reconciliation of Columbia's firm peak day capacity entitlement level with Columbia's future years' firm design day demand per Columbia's 2024 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 hourly flow restrictions established in EGTS's tariffs. This shows that Columbia's current peak day capacity level is 103.8%, which is just outside 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. How much capacity would need to be reduced in order to be within the 103% policy?

A. The amount of capacity over the 103% is approximately 4.8 MDth.

Q. Please explain the reason for Columbia being outside the 103% policy, as reflected in TMM-2 and Revised Exhibit 15.

A. Columbia's Revised Exhibit 15 provides an analysis regarding the 103% policy, the reason for slightly exceeding the policy such that Columbia's existing available capacity equals 103.8 percent of projected firm demand for contract year 2028-29, and Columbia's plan for possible mitigation. The percentage identified in Revised Exhibit 15 was predicated on Revised Exhibit 5, Table 4 (Sheet 9). This table shows Columbia's capacity for the years 2025/26 through 2028/29 compared to the design day requirements. As noted earlier in my testimony, the TCO FT marketed release, which ranged from 3 MDth to 5.2 MDth in the original Exhibit 5, was removed in Revised Exhibit 5, Table 4 (Sheet 9). This removal increases the reduction to capacity, which changes the excess from the original calculation of 102.9% to 103.8%. Historically, this release has been included in the calculation in the amount of 5.2 MDth.

Q. Please explain the nature of this release and why the release is not included in the calculation for determining peak day calculation.

A. This is a marketed TCO FT non-recallable release to a large industrial customer

located in PSP 29. Columbia holds capacity rights into this market, yet the industrial customer is the Company's only customer located in PSP 29. This release has been in place since 2007, with the current release set to expire on October 31, 2025. In recent discussions with the customer, they have indicated their intention not to continue with the release beyond October 2025. Given the timing of the notification and this filing, Columbia has not been able to determine if it can release this capacity for the upcoming winter. Therefore, I have excluded the marketed release in the projected capacity calculation in Exhibits TMM-1 and TMM-2.

Q. What are Columbia's intentions with this capacity if the release is not executed?

A. Columbia is currently evaluating its options for this capacity, including another marketed release. There is a level of uncertainty, however, because TCO has a rate case pending at FERC, which includes a proposed tariff change that would impact Columbia's capacity portfolio.

Q. What tariff change is TCO proposing that may impact Columbia's portfolio?

A. As described in Exhibit 3 and discussed later in my testimony, TCO filed a Section 4 rate case at FERC. Included in its filing is a proposal to implement 1/24th hourly rights on TCO's system. At the time of this writing, these tariff changes are set to be effective April 1, 2025. The proposed language in TCO's pre-filed tariff section 12.1 Maximum Daily Delivery Obligation at Delivery Points states: "Unless otherwise specified in an applicable Service Agreement, Transporter will use 1/24th of the

MDDO [Maximum Daily Delivery Obligations] for such hourly design purposes. Transporter retains the right to restrict Shipper activity in excess of this hourly design under Section 17 of the General Terms and Conditions."

Q. If FERC approves this tariff change, what will be the implications for Columbia?

A. As reflected in Exhibit TMM-1, Columbia holds a significant amount of storage and transportation on TCO, which is approximately 79% of its total capacity portfolio (or 531 MDth/day). If TCO were to hold Columbia to 1/24th of hourly rights, it would require supplying customers to meet their maximum hourly demand multiplied by 24. Therefore, on days where Columbia is under the hourly restriction, it would need to secure supply to meet its hourly maximum demand times 24, which would likely exceed the total daily demand. In addition, as temperatures grow colder, there are greater chances of the maximum hourly demand exceeding the daily Maximum Daily Quantity ("MDQ") Columbia has contracted. Therefore, Columbia would likely need to contract additional capacity over its design day requirements in order to meet the maximum hourly demand on TCO. Columbia would have to provide an hourly adjustment to its design day requirement to be included in the calculation, similar to the adjustment made for areas served by EGTS.

Q. Was the max hourly adjustment included in Exhibit TMM-2 approved in last year's 1307 (f) proceeding?

A. Yes, Columbia received approval in last year's 1307 (f) proceeding for the inclusion of a max hourly adjustment for its EGTS capacity in its calculation of design day

demand and capacity.

Q. Has Columbia developed the hourly adjustment needs for its TCO capacity?

A. Yes, Columbia has conducted a preliminary analysis for its TCO markets to determine hourly needs. This analysis shows an additional 43,794 Dth would be necessary to meet maximum hourly needs across the TCO markets. If this were to be included in Exhibit TMM-2, it would show a supply deficit of 19,800 Dth, or -2.8%.

Q. Have you included this hourly adjustment in Exhibit TMM-2?

A. No, due to the uncertainty of the outcome of TCO's rate case, this was not included in Exhibit TMM-2.

Q. What is Columbia's proposal regarding its capacity portfolio?

A. Due to the uncertainty surrounding TCO's 1/24th hourly tariff proposal and its significant impact to Columbia's capacity portfolio, Columbia proposes to evaluate its capacity portfolio and design day requirements and provide an update in next year's 1307 (f) filing. Doing so would allow time for resolution of TCO's rate case filing and implementation of TCO's tariff proposal, if approved. Further, this would provide Columbia an opportunity to perform an updated design day forecast and analyze whether changes to Columbia's capacity portfolio are needed.

III. <u>COLUMBIA'S SUPPLY</u>

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 53 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. Columbia requires each NGS to have a minimum of one aggregation group for all 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 in this instance, 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 system up to the point where customers take delivery;
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 the distribution system.

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 Point of Delivery ("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. No, as denoted in Revised Exhibit 5, Sheet 20, Columbia did not enter into any of these transactions with an affiliate for the period under review.

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 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. 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 in Company Exhibit 3, Columbia was an active party to numerous FERC proceedings in calendar year 2024. Columbia has been similarly active in the first quarter of 2025. 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 2024, 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. On February 1, 2024, the suspended and revised tariffs went into effect. FERC issued final approval of the Settlement on July 11, 2024.

5) On September 30, 2024, TCO filed a revised tariff record that supports a system-wide general increase in TCO's rates, and includes changes to TCO's rates, rate schedules, and General Terms and Conditions ("GT&C"), effective April 1, 2025 (RP24-1103). The Company filed protest intervention on October 15, 2024. The Company also joined an LDC Customer Group to increase leverage for an equitable settlement. FERC approved rates and suspended the tariff records and rates until April 1, 2025. Effective April 1, 2025, TCO will implement these rates and tariff changes subject to refund. Settlement meetings are ongoing at this present time. Hearings will start in

September 2025.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT TMM-1

Columbia Gas of Pennsylvania, Inc
Firm Peak Day and Annual Entitlements
Contract Year 2025-26

Supply Source	Peak Day Entitlements Daily (MDth/Day)	Peak Day Entitlements Percentage (%)	Annual Entitlements [1] Annual (MDth/Yr)	Annual Entitlements [1] Percentage (%)
Storage				
TCO FSS	395.7	59%	21,481	20%
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	22%
Firm Transportation (City Gate)				
TCO	134.9	20%	49,250	47%
Eastern Gas Transmission	5.2	1%	1,896	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	12%
National Fuel FTS	5.8	1%	2,123	2%
Total City Gate FTS	223.6	33%	81,600	78%
Local Production				
Direct into CPA	0.7	0%	256	0%
TOTAL CITY GATE SUPPLY	670.3	100%	105,180	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 2025-26, 3,139 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 2025-26, 9,384 Dth of the winter season firm transportation capacity will be charged to and utilized in the provision of EBS Option 1.

EXHIBIT TMM-2

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

Contract Year	**2025/26**	**2026/27**	**2027/28**	**2028/29**
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	134.9	134.9	134.9	134.9
Eastern Gas Transmission[1]	5.2	5.2	5.2	5.2
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	5.0
Equitrans	35.9	35.9	35.9	35.9
National Fuel FTS	5.8	5.8	5.8	5.8
Total City Gate FTS	223.6	223.6	226.6	228.6
Local Production				
Direct into CPA	0.7	0.7	0.7	0.7
TOTAL CITY GATE SUPPLY	675.5	675.5	678.5	680.5
Less Capacity to provide Standby	5.4	5.4	5.4	5.4
Less Capacity to provide EBS	12.5	12.5	12.5	12.5
Net Capacity	657.6	657.6	660.6	662.6
2024 DDF FIRM REQUIREMENT	625.5	626.8	627.9	628.8
Max Hour Adjustment	9.8	9.8	9.8	9.9
Adjusted 2024 DDF Firm Requirement	635.3	636.6	637.7	638.7
DIFFERENCE	22.3	21.0	22.9	23.9
% OF DEMAND	3.5%	3.3%	3.6%	3.8%
2024 DDF FIRM REQUIREMENT plus 3%	654.3	655.7	656.8	657.8
DIFFERENCE	3.3	1.9	3.8	4.8
% OF DEMAND	0.5%	0.3%	0.6%	0.8%

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

§53.64(c)(6) Each Section1307(f) utility shall file with the Commission a statement of its current fuel procurement practices, detailed information concerning the staffing and expertise of its fuel procurement personnel, a discussion of its methodology for obtaining a least cost and reliable source of gas supply, including a discussion of any methodologies, assumptions, models or rules of thumb employed in selecting its gas supply, transportation and storage mix, its loss prevention strategy in the event of fraud, nonperformance or interruption of performance, its participation in capacity release and reallocation programs, the impact, if any, upon least cost fuel procurement by constraints imposed by local transportation end users, interruptible service, balancing, storage and dispatching options, and its strategy for improving its fuel procurement practices in the future and timetable for implementing these changes.

Response:

OVERVIEW

Columbia Gas of Pennsylvania, Inc.'s ("CPA") supply objective is to secure and deliver competitively priced, reliable gas supplies to meet its customers' demand at least cost. CPA utilizes its portfolio of firm transportation and storage capacities on interstate pipelines and its portfolio of term and spot market supplies to achieve this objective.

As both a merchant provider of gas and a distributor of customer-owned gas, CPA has the responsibility to balance the supply and demand for all customers at the city gate on all days, including both design cold days when demand is at peak high levels and warm days when demand is at minimal levels. CPA incorporates this daily balancing requirement into its planning process, relying upon the injection and withdrawal capabilities of its contracted storage services and the negotiated flexibility in some supply contracts to provide for the daily swings in customer demand.

Within its Energy Supply and Optimization ("ES&O") Department, CPA determines what supply and capacity contracts, and contract volumes are necessary for the long term to minimize gas supply and capacity costs, giving consideration to such factors as reliability, flexibility, diversification and the likelihood of various price and demand forecasts. ES&O's Planning section is responsible for determining the appropriate components of CPA's capacity portfolio and performing strategic supply planning functions. Planning utilizes the PLEXOS® Software as its primary planning tool.

PLEXOS® is used to determine the volumes of flowing supplies and storage withdrawals/injections which will minimize gas supply commodity costs while preserving reliability. Results of CPA's PLEXOS® driven planning efforts are utilized to guide the purchasing of gas supplies and contracting for the necessary pipeline capacity.

On a day-to-day basis, ES&O determines CPA's expected system-wide demand and the supply required from all supply contracts and storage to meet customer demand. Further, ES&O is responsible for ensuring that deliveries to Pipeline Scheduling Points ("PSPs") are within applicable contract entitlement levels and comply with any pipeline operational notices. Collectively, the ES&O and the Customer Programs and Billing Departments determine when actions are required of CPA's transportation and CHOICE℠ customers to maintain system integrity. CPA seeks to invoke such actions by issuing Operational Flow Orders ("OFOs"), Operational Matching Orders ("OMOs") and/or Seasonal Flow Orders ("SFOs"). CPA attempts to precede any such order with an Operational Alert ("OA") or Emergency Alert ("EA").

Information generated within ES&O is used to guide CPA's term contracting and spot market purchasing practices, the release and recall of capacity, and the determination of operational storage targets, storage management and off-system sales. ES&O manages CPA's term, spot market and peaking supplies and is responsible for CPA's off-system sales transactions. ES&O nominates and schedules all volumes on upstream interstate pipelines, manages CPA's capacity release program, including releases to Natural Gas Suppliers ("NGSs") under CPA's CHOICE℠ program and uses its transactional information to reconcile all supply and capacity invoices from suppliers, and to generate off system sales invoices.

The Nominations section within Customer Programs and Billing manages General Distribution Service ("GDS") customer and CHOICE℠ supplier daily nominations, confirming supplies and allocating volumes to customers for billing and operations. CPA utilizes the daily GDS and CHOICE℠ volume information as an input in planning and managing its own supply and storage activity.

The remainder of this exhibit is comprised of the following sections:

- Demand, which includes discussions on annual, seasonal and peak day demands;
- PLEXOS® Optimization Model;
- Capacity;
- Operation of Storage;
- Supply Contracts and Daily Balancing;
- Services for CHOICE℠ Customers;
- Federal Regulatory Activities; and
- Off-system Sales and Capacity Release Incentive Program.

DEMAND

Monthly and Seasonal Demand: Three Weather Scenarios

The first step in CPA's gas supply process is the determination of customers' energy needs. Projected customer demand is based upon weather-normalized historical consumption adjusted to reflect factors such as conservation, appliance efficiency improvements and customer additions and deletions. The net result is a projection of monthly demand that CPA uses for planning purposes. CPA projects demand and supply purchase requirements for its remaining Sales Service customers, provides daily balancing for the demands of its Customer CHOICE℠ customers, and makes contingency plans for a range of firm customer demand driven by varying weather conditions and the possible failure of a CHOICE℠ NGS's supply. Finally, CPA provides Standby Service under Rate SS to those GDS customers that contract for it, and Elective Balancing Services ("EBS") for all GDS customers. Under EBS, GDS customers choose one of two options: Option 1 - Full Balancing Service (ability to carry a positive bank from month to month); or Option 2 - Monthly Cash out (Intra-month Banking Service). EBS gives GDS customers flexibility in managing their supply and demand. The demand of CPA's Sales Service and CHOICE℠ Service customers is highly weather sensitive with approximately 75 percent of normal weather annual demand occurring during the winter. CPA defines the winter season as the months of November through March and the summer season as the months of April through October.

CPA considers three design weather scenarios in the development of its least cost supply plan: 1 in 10 colder, normal and 1 in 10 warmer. These scenarios are developed to capture the uncertainties related to winter demand. For the summer, CPA develops only a normal weather demand scenario. CPA combines the three winter scenarios with the summer scenario to determine three contract year scenarios.

The normal weather scenario provides a forecast based upon the 20-year average of degree days for the full year.

The colder weather scenario reflects an increase in total winter season degree days based on a 1 in 10 or 10 percent variance for winter season degree days. The 10 percent variance for the colder weather scenario means that there is a 10 percent probability that the winter will have more degree days than the planned colder scenario.

The warmer weather scenario is based upon a 1 in 10 or 10 percent variance. The 10 percent variance for the warmer weather scenario means there is a 10 percent probability that the winter season will have fewer degree days than the planned warmer scenario. Table

1 presents the demand forecasts for the three weather scenarios. For purposes of the requirements projection in this filing, CPA utilizes the normal weather demand forecast.

Table 1. Projected customer demand for the colder, normal and warmer weather scenarios. The projected customer demand excludes standby volumes.

Projected Customer Demand for Weather Scenarios
October 2025 – September 2026 (Mdth)

	Colder	Normal	Warmer
Sales Excluding CHOICE℠ :			
Residential	29,282	27,372	25,462
Commercial	9,141	8,545	7,948
Industrial	392	374	355
Other	575	575	575
Subtotal	39,390	36,865	34,341
CHOICE℠	9,865	9,234	8,602
Total	49,254	46,099	42,943

As noted from Table 1, CPA's projected Sales and CHOICE℠ customer demand varies by about 6.3 MMDth between the Colder and Warmer weather scenarios. CPA's supply portfolio is designed to enable CPA to deliver supplies reliably to its customers while minimizing the cost to serve this uncertain demand.

Design Weather Conditions.

On all days, including days of peak demand, CPA must be ready to serve the demand of Sales Service customers and to provide balancing for CHOICE℠ Service customers. Therefore, to ensure reliability, CPA has established design parameters for estimating Sales Service and CHOICE℠ Service customer demand under extreme weather conditions. CPA's Design Day Forecast is based on Design Day conditions consisting of:

- Current Day Design Temperature;
- Prior Day Design Temperature;
- Current Day Design Wind Speed; and
- Occurrence on a Weekday.

CPA updates the design conditions approximately every five to ten years. The most recent update was in 2015 and the 2024 Design Day Forecast incorporates the results. CPA determines the Design Day conditions by weather station, and then determines pipeline scheduling point and company-wide design conditions by weighting.

To determine the Current Day Design Temperature for a weather station, CPA fits a Gumbel probability distribution to the collection of minimum daily temperatures for each winter season, one daily temperature per season. The Gumbel probability distribution is used because the distribution of historical temperatures is skewed. CPA fits a probability distribution to the historical daily temperatures so that it can estimate the future risk of the occurrence of any temperature. With CPA's Design Day Risk Criteria of 1 in 15, the probability is 6.67 percent that any winter will have one or more days with an average daily temperature equal to or colder than the Current Day Design Temperature. The associated company-wide Current Day Design Temperature of -5° Fahrenheit has occurred or been exceeded on five occasions since the winter of 1949/50. The latest was January 19, 1994 when the average temperature was -6° Fahrenheit. Within this time period, CPA's coldest average daily temperature of -8° Fahrenheit was recorded on two occasions; January 17, 1982 and January 18, 1994.

The Prior Day Design Temperature is determined from the mean temperature difference between historical cold days and their associated prior days. Cold days, for the purpose of determining the Prior Day Design Temperature, are defined as those which are no warmer than the Current Day Design Temperature plus 5° Fahrenheit.

Current Day Design Wind Speed is based on an analysis of wind activity for the 1991/92 through 2014/15 winters. This analysis determines the average wind speed on cold days, where cold days are defined as days that are no warmer than the Current Day Design Temperature plus 15° Fahrenheit.

Design Day Demand and Date

CPA utilizes multivariable linear regression analysis to determine Design Day Demand. CPA's methodology is discussed in its 2024 Design Day Forecast, which is included in this filing as Exhibit No. 13. Table 1 shows the 2024 Design Day Forecast for the 2025-2026 winter season. As shown, a large majority, approximately 76 percent or 626 MDth/day, of CPA's Design Day requirements are for Sales Service and CHOICE℠ Service customers. CPA contracts for firm capacity for these customers.

Table 2. Presents the Design Day Demand forecast for the winter season 2025-26. The Design Day Demand excludes standby and EBS volumes.

Winter Season 2025-26 Design Day Demand (MDth/Day)

	Sales and CHOICE℠	GDS	Total
Residential	450.6	0	450.6
Commercial	171.2	102.2	273.4
Industrial	1.7	97.6	99.3
Other	2.0	0	2.0
Total:			
Volume	625.5	199.8	825.3
Percent	76 percent	24 percent	100 percent

For capacity planning purposes CPA forecasts Design Day Demand for five years into the future. This projection incorporates the projected purchased gas cost ("PGC") rate and associated retail rates in November, and the customers' sensitivity to price. Analysis indicates that high retail gas rates at the beginning of the winter correlate with increased customer conservation.

Table 3. Presents the Design Day Demand forecasted for the winter seasons 2025-2026 and 2026-2027. The Design Day Demand excludes standby and EBS volumes.

Winter Season 2025-2026 and 2026-2027 Design Day Demand (MDth/Day)

	Sales and CHOICE℠	GDS	Total
2025 – 2026	625.5	199.8	825.3
2026 – 2027	626.8	201.6	828.4

Daily deliverability from CPA's contracted pipeline storage services declines during the winter season as storage inventory is withdrawn. To help ensure reliability on late winter days, CPA determines a Design Date of Occurrence for the Design Day. For its portfolio design, CPA determines, with 10 percent risk, the latest date within a winter season of a design temperature or colder occurring for the CPA service area. Since there are only a few historical observations in this analysis, CPA uses a "t - distribution" to calculate the Design Date, January 25**.**

Maximum and Minimum Daily Demands by Month

In addition to the Design Day Conditions for the winter season, CPA has established Winter Monthly Cold Conditions for Long Range Planning, a period of five years into the future. A capacity portfolio must enable CPA to serve customer demand throughout the winter, including the monthly design days.

For each month, CPA analyzed temperatures since 1950 to determine the coldest daily temperature with 1 in 10, or 10 percent risk level. That is, for each month, the probability is 10 percent that the month will have one or more days with an average temperature equal to or colder than the Winter Monthly Cold Design Temperature.

Winter Monthly Cold Design Conditions enable CPA to plan for extreme demands that may occur within any winter month. CPA utilizes coefficients developed from monthly multivariable linear regression models to estimate the firm and total customer demand for the Winter Monthly Cold Design Temperatures.

The estimates of monthly maximum demands help CPA to develop its least cost supply plan by providing adequate supply in the event of late winter cold temperatures while concurrently helping to establish levels of recallable and non-recallable capacity release volumes.

CPA also estimates the minimum daily demand for each month that would occur under warm conditions. The minimum daily demand for each month is based on an analysis of the daily demands that have occurred during that month over the most recent five years of history. The estimated minimum daily demand for each month is calculated based on a normal distribution fit to the daily demands, and a 10 percent probability of occurrence.

PLEXOS® OPTIMIZATION MODEL

To reflect the constraints in pipelines' tariffs and to ensure optimum use of its supply contracts and pipeline entitlements, CPA uses the PLEXOS® Software, provided by Energy Exemplar, as its primary tool for supply planning. CPA purchased the PLEXOS® Software in conjunction with its affiliated Columbia Distribution companies. Through this association CPA is permitted full use of the PLEXOS® model while incurring a portion of the maintenance fee.

PLEXOS® is a PC based decision support modeling system, which uses linear programming, a mathematical “global optimization" method, to determine the least cost gas supply. PLEXOS® provides a solution to the problem of choosing and scheduling gas supply quantities to flow time-dependently through a gas supply and transportation/storage network. CPA uses PLEXOS® to model geographic demand regions and their operational

gas flow limitations. PLEXOS® measures CPA's ability to balance supply and demand under colder, normal, and warmer weather scenarios.

CPA utilizes the PLEXOS® model for two primary purposes: (1) Long-Term Planning and (2) Operational Planning.

Long-Term Planning generally covers a time horizon of five years. Long-term planning includes analysis of capacity portfolio options, and projections of gas supply costs. The goal of the PLEXOS® analysis is to minimize total costs including the capacity costs and the variable operating costs while maintaining reliability.

Operational Planning incorporates existing market conditions to determine an optimum plan for utilization of available supplies and capacity over the short term, up to 12 months. CPA develops a short-term supply plan on a monthly basis utilizing PLEXOS®, with more frequent updates as needed. These plans incorporate all of the storage constraints discussed later in this exhibit and are used to determine purchases, capacity use and storage utilization. In the short term, both capacity and the capacity costs are generally fixed, so the goal of this PLEXOS® analysis is to minimize the variable operating (commodity) costs. Costs taken into account in this process include:

- supply contract commodity costs;
- transportation commodity costs to the city gate;
- storage injection costs;
- storage withdrawal costs; and
- fuel.

Total system variable operating cost is minimized subject to various physical and contractual constraints, including:

- the daily flow restrictions on system components;
- pipeline transportation capacities; maximum storage injection and withdrawal rates;
- Storage inventory limits and ending target levels.

CAPACITY

Capacity Portfolio

As stated at the outset of this exhibit, CPA's supply objective is to secure and deliver competitively price, reliable gas supplies. To assure reliability, CPA uses firm capacity in its gas supply plan to serve Design Day Demand.

Table 4. Details CPA's projected Design Day Demand based on CPA's 2024 DDF and firm capacity for the next four winter seasons.

Firm Peak Day Capacity and Demand (MDth/Day)

	Contract Year			
	2025-26	**2026-27**	**2027-28**	**2028-29**
Demand of Sales and Choice Customers				
Residential	450.6	450.7	451.6	452.0
Commercial	171.2	172.4	172.6	173.1
Industrial	1.7	1.7	1.7	1.7
Other	2.0	2.0	2.0	2.0
Total	625.5	626.8	627.9	628.8
Max Hour Adjustment	9.8	9.8	9.8	9.8
Total Demand	**635.3**	**636.6**	**637.7**	**638.6**
Capacity				
Firm Transportation				
TCO	134.9	134.9	134.9	134.9
Less Marketed Capacity Releases	0	0	0	0
Net TCO	134.9	134.9	134.9	134.9
EGTS	5.2	5.3	5.3	5.3
Equitrans	35.9	35.9	35.9	35.9
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	5.0
National Fuel Gas Supply Corp.	5.8	5.8	5.8	5.8
Subtotal, net of releases and assignments	223.6	223.6	226.6	228.6
Firm Storage				
EGTS GSS	28.8	28.8	28.8	28.8
EGTS GSS Max Hour adjustment	5.160	5.160	5.160	5.160
TCO FSS	395.7	395.7	395.7	395.7
Equitrans	19.1	19.1	19.1	19.1
National Fuel	2.4	2.4	2.4	2.4
Total	451.2	451.2	451.2	451.2
Local Direct	0.7	0.7	0.7	0.7
Total Firm Capacity				
Gross	675.5	675.6	678.6	680.6
Less Capacity to provide Standby	(5.4)	(5.4)	(5.4)	(5.4)
Less Capacity to provide EBS	(12.5)	(12.5)	(12.5)	(12.5)
Net Capacity	**657.6**	**657.7**	**660.7**	**662.7**
Difference: Capacity less Demand	22.3	21.1	23.0	24.0

Firm Peak Day Capacity and Demand (MDth/Day)

CPA's available capacity is approximately 103.8 percent of projected firm demand, adjusted for a maximum hour design for contract year 2028-29, the highest projected design day firm requirements in CPA's 2024 Design Day Forecast. CPA is subject to hourly flow restrictions on EGTS pipeline and needs to hold enough capacity to meet the hourly restriction. Failure to comply with EGTS' hourly flow restrictions could lead to assessment of penalties and potential system reliability issues. Therefore, the design day requirements have been adjusted to reflect the additional maximum hour requirement. The variance is outside the bounds contained in CPA's Portfolio Design policy, which provides that CPA will have sufficient capacity to be within a range of up to 103 percent of the highest of its projected design day firm requirements for the five-year period of its Design Day Forecast. Continuation of CPA's Portfolio Design policy was a requirement in the Settlement of CPA's 2013 1307(f) proceeding (Docket No. R-2013-2351073).

In order to meet this parameter, Columbia would need to reduce its capacity by 4,800 Dth. In Exhibit 5, Table 4 submitted in CPA's pre-filing on February 28, 2025, there was a marketed release in the amount of 5,200 Dth. After submission of the initial filing, the large customer that has this release through October 31, 2025, indicated its intention not to continue with the release. Therefore, this release was removed in Revised Exhibit 5,Table 4, which resulted in an increase in the excess to 103.8%. Columbia Gas Transmission ("TCO") filed a rate case at FERC, which contains a proposal for 1/24th hourly limitations. Pursuant to FERC rules, this proposed tariff change will become effective April 1, 2025, before the conclusion of TCO's rate case. This could have a significant impact on CPA's capacity requirements to meet the hourly limitation. Therefore, CPA plans to evaluate its portfolio based on the outcome of the 1/24th hourly limit pursuant to TCO's rate filing and its updated design day requirements analysis for 2025.

As indicated in Revised Exhibit 5, Table 4, CPA's capacity portfolio contains a substantial amount of storage. Storage capacity enables CPA to purchase a majority of its annual customer requirements during the seven summer months. Some of the summer purchase volume is used to serve current customer demand, while storing most of the volume to serve customer demand the following winter. Since CPA uses FTS to fill storage in the summer and to serve current demand in the winter, the annual FTS capacity utilization factor is relatively high.

TCO provides approximately 71 percent of CPA's winter season demand and about 79 percent of CPA's Design Day capacity. TCO is an unaffiliated interstate pipeline. CPA's service territory lies in eight TCO PSPs, contained within two TCO Operating Areas. Each

PSP is synonymous with a single or group of geographically related delivery points to CPA's distribution system otherwise known as a Master List of Interconnections ("MLI").

The vast majority of CPA's TCO capacity also has grandfathered Maximum Daily Delivery Obligation ("MDDO") and Daily Delivery Quantity ("DDQ") rights. These grandfathered MDDO and DDQ rights provide CPA the necessary flexibility to receive varying volumes at each of its approximately 300 individual receipt points from TCO each day. This flexibility and associated benefits are derived from the grandfathered MDDOs and DDQs under this contract that exceed the contract Total Firm Entitlement ("TFE"). As a consequence, TCO is obligated to maintain capacity to individual meters, that in total, is in excess of the TFE, and at a minimum, sufficient to meet CPA's contractual MDDO/DDQ rights at each point of delivery. These grandfathered MDDO/DDQ rights are not available in new contracts for TCO capacity and any reduction in contracts containing excess grandfathered MDDO/DDQs would result in a proportional reduction in the grandfathered rights. Additionally, this flexibility is critical to the efficient operation of CPA's transportation services, both GDS and CHOICE^{SM}, and the efficient, least cost management of CPA's capacity portfolio (See Balancing Among Geographic Regions, below).

CPA contracts for storage service from Equitrans under Rate Schedule 115SS, effective April 1, 2020. A portion of the capacity under this contract is used to provide service to GDS customers under CPA's Elective Balancing Service (EBS) with the balance of its use limited to specific geographic areas. The 115SS storage contract has an MDQ of 19,130 Dth, and seasonal storage capacity of 2,000,000 Dth. To deliver this storage service, CPA contracts for 19,130 Dth/day of Equitrans No Notice Firm Transportation Service (NOFTS). In addition, CPA also has an additional 17,000 Dth/day of NOFTS for flowing supply and another 18,870 Dth/day of Firm Transportation Service. Overall, CPA has 55,000 Dth/day of firm capacity with Equitrans.

CPA also contracts for storage service from Eastern Gas Transmission and Storage, Inc. (EGTS) under Rate Schedule GSS and associated FTNN service to provide EBS service. One of these GSS and FTNN contracts is used in concert with the above noted Equitrans capacity to provide EBS. This GSS and FTNN contracts provide a maximum of 4,800 Dth daily and 240,000 Dth of seasonal storage capacity. These contracts were renewed through March 31, 2029. Additionally, CPA contracts for additional storage and related firm transportation service under Rate Schedules GSS, FTNN-GSS and FT with EGTS. CPA has two additional storage capacity contracts under Rate Schedule GSS; one has an MDQ of 9,000 Dth and associated seasonal storage capacity of 941,176 Dth and the second has an MDQ of 15,000 Dth and associated seasonal storage capacity of 930,000 Dth . CPA has two FTNN service contracts for 6,000 Dth per day and 15,000 Dth per day. Additionally, CPA has an FT service for 3,000 Dth per day during the winter which reduces to 2,000 Dth per day in the summer which was renewed through March 31, 2028. CPA also has two FT contracts, one for 5,000 Dth and one for 255 Dth that expire March 31, 2030. CPA utilizes

the first FTNN contract and the FT (winter) contract to match the MDQ of the first storage contract noted above which provide firm storage supplies to CPA's Warrendale market. The first FTNN contract (6,000 Dth per day) has a primary termination date of March 31, 2028. CPA utilizes the second FTNN and FT contracts to serve its State College market. CPA continues to evaluate capacity and supply options in these markets to address the hourly demand requirements on EGTS.

CPA has several forward haul contracts with Texas Eastern Transmission (TETCO) that serve markets in TETCO zones M-2 and M-3 and a seasonal (Dec-Mar) backhaul contract that serves M-3 markets. CPA requires these contracts to serve isolated portions or all of its Uniontown, State College, and York area markets.

CPA solicited bids for replacement capacity for contract 910951 and none were received. As a result, in October 2024, CPA renewed contract 910951 through October 31, 2026, that delivers 14,835 Dth/Day into the TETCO Delmont, Rockwood, and/or Pleasant Gas market.

In April 2023, CPA placed a bid for capacity as part of TETCO's Appalachia to Market III (A2M3) open season. CPA's market in PSP 25 has shown continued growth and additional capacity is needed to meet projected demand growth. CPA and TETCO have negotiated a precedent agreement where CPA would have 3,000 Dth/day of new capacity to CPA's York market through October 31, 2028 and 5,000 Dth/day on and after November 1, 2028. The new capacity is projected to be on-line in November of 2027. The initial term of the transportation contract is 15 years.

CPA has two contracts with Tennessee Gas Pipeline (TGP) that serve portions of its Newcastle and Pittsburgh area markets, one of which is a newer contract with a primary receipt point in the Commonwealth.

CPA obtained under the Right-of-First-Refusal ("ROFR") process a renewal of its Firm Transportation Service (FT-A) contract for 16,000 Dth/day to serve the Newcastle market. This contract has a new expiration date of October 31, 2029.

CPA determined the market served by the Eastern Gas Transmission & Storage (EGTS) Warrendale POD and the Tennessee Gas Pipeline (TGP) Bradford Woods (aka Pitt Terminal) POD needs additional capacity to supply the design day demand. CPA entered into a new contract for 9,300 Dth/day of additional firm capacity to satisfy these needs. This capacity was a winter only contract from November 1, 2024 through March 31, 2025. This capacity may be renewed in the future or additional options may be pursued.

CPA also has contracts with National Fuel Gas Supply Corporation (National). One contract consists of enhanced firm transportation (EFT) of 4,000 Dth per day, of which 1,571 Dth per day with receipt 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's storage receipt point and also delivered to the CPA Findlay Township meter station. National also has a firm transportation (FT) contract for 4,245 Dth per day. Additionally, National will provide an enhanced storage service (ESS) with a MSQ of 267,143 Dth, a MDIQ of 1,571 Dth per day, and a MDWIQ of 2,429 Dth per day to be used in combination with the EFT service.

Adding or Replacing Capacity

Before CPA contracts for interstate pipeline capacity, it reviews both open season offerings of new capacity and bulletin board postings of existing capacity. CPA also considers any viable capacity offered by pipelines that currently serve CPA or could do so in the future. Exhibit 2 summarizes proposed capacity services which CPA became aware of, and evaluated in the 12 month period ending January 31, 2024.

CPA may also obtain capacity as follows:

- Natural Gas Suppliers ("NGSs") operating in Pennsylvania, CPA customers and other third parties are given the opportunity to provide capacity comparable to capacity that CPA has under contract and that is approaching expiration.
- If CPA does not have sufficient capacity to meet its Design Day requirements CHOICE[SM] NGSs are given the opportunity to provide FTS capacity for one-year periods.

In more detail, the procedures for obtaining capacity from NGSs are as follows.

Expiration of an Existing Contract and Request for Proposal (RFP) to Natural Gas Suppliers (NGSs)

When the expiration date of an existing capacity contract approaches, CPA gives NGSs licensed to operate in CPA's service territory, CPA customers and other third parties the opportunity to provide comparable capacity. Certain capacities that meet one or more of the following conditions may be excluded:

- operationally necessary to serve CPA's customers,
- required to provide Supplier of Last Resort ("SOLR") services,
- required to provide system balancing.

Considering these conditions, CPA issues RFPs to the NGSs, CPA customers and other third parties offering them the opportunity to provide replacement capacity. The RFP specifies the delivery points required by CPA to receive gas supplies and outlines the daily delivery volumes for each delivery point. CPA will consider any viable offers it receives. If CPA determines that an offer complies with its RFP and is the best option available, it will enter into an agreement with the offering party. This process of seeking and accepting an offer from an NGS, CPA customer or other third party must be completed in time to allow CPA to terminate the existing capacity that was the subject of the RFP. If acceptable offers are not received, CPA will either extend the existing contract under its own terms and rollover rights or renegotiate the contract. No offers of replacement capacity were received by CPA.

An example of this procedure is CPA's RFP related to its National Fuel capacity. CPA's contract with National Fuel is currently operating on a month-to-month rollover basis and is reviewed annually. In April, 2023, CPA issued an RFP for capacity to replace the National Fuel capacity, effective November 1, 2023. CPA did not receive any responses to its RFP. Therefore, Columbia exercised its annual rollover right and retained the National Fuel capacity under existing contractual provisions, since this capacity is needed to serve the Warren market area.

Additional Capacity Resource Requirement ("ACRR")

Under the CPA CHOICE^{SM} Program, NGSs serving CHOICE^{SM} customers provide a constant volume of daily supply, equal to the expected annual demand of their customers divided by 365 days.

Effective November 1, 2004, CPA implemented a procedure that gives CHOICE^{SM} NGSs the opportunity to provide FTS capacity, for one-year periods beginning each November 1, if CPA does not have sufficient capacity to meet its Design Day Demand. The process works as follows:

- CPA determines the Additional Capacity Resource Requirement ("ACRR"), if any, needed to meet its Design Day Demand.
- CPA notifies NGSs of the ACRR by April 1 of each year.
- The NGSs have the opportunity, until June 1, to offer to provide capacity. The volume of any capacity offered by a CHOICE^{SM} NGS may not exceed the daily supply volume of the NGS's aggregation group.
- Should CPA receive offers that in total exceed the ACRR, CPA will accept the offers on a first-come basis until the ACRR is eliminated.

As reflected in Table 4, CPA projects it will have sufficient capacity for the winter of 2025-26 and therefore will not seek additional capacity from NGSs serving CHOICE^{SM}

customers through the ACRR process for contract year 2025-26. CPA will review its Design Day supply balance again before the 2026-27 winter season to determine if capacity will be sought through the ACRR process for the 2026-27 contract year.

OPERATION OF TCO STORAGE

Operation Guidelines

As noted on Table 4, approximately 67 percent of CPA's Design Day capacity is provided by storage. In addition, CPA relies upon storage to provide approximately 53 percent of its normal weather, winter season supply to meet the needs of its firm customers and balance system requirements.

CPA follows six guidelines in using its major storage service, TCO FSS:

- to preserve maximum daily storage deliverability on the Design Day and to delay storage ratchets until the design ratchet dates, as presented in Table 5
- to protect the ability to serve customer requirements during a design cold winter season or month;
- to reserve sufficient TCO storage volumes, at least two percent of contracted seasonal storage quantity, as of April 1 to protect against potential cold temperatures in April;
- to spread TCO FSS storage injections over the months April through October so that no month has a planned injection exceeding 95 percent of the contractual limit for the month;
- to fill TCO storage to 95-99 percent of Seasonal Contract Quantity ("SCQ") on November 1, leaving flexibility to allow for injections on warm days in early November; and
- to use this storage capacity consistent with least cost planning.

CPA's strategy for TCO storage is sufficiently flexible to match customer requirements, under all planning scenarios, while:

- providing the economic benefit from storage utilization, and
- adhering to the operating conditions of TCO storage tariffs.

Using the above storage guidelines, CPA develops a supply plan consisting of seasonal and contract year supply/demand balances. The plan identifies total monthly sources of

supply to be used for the colder, normal, and warmer contract year weather scenarios. The scenario incorporating the colder winter weather constitutes the Design Conditions for which the supply plan is developed.

Tariff Restrictions

Under TCO's tariff, CPA must plan the use of storage such that no more than 65 percent of its TCO FSS seasonal storage quantity remains in inventory after February 1st, and no more than 25 percent after April 1st. In warmer weather winters, this limit may require downward swings in the volume of flowing gas, the gas that CPA has purchased and is transporting to its service territory using its FTS capacity. Downward swings in flowing volumes must be carefully implemented given the potential occurrence of Design Day or extreme cold conditions at any time during the colder winter months. Since CPA requires all flowing supplies to meet firm Design Day Demand, CPA must be able to recall or replace any flowing volumes reduced to comply with storage delivery limits.

If CPA does not reduce its volume in storage to meet the February 1st and April 1st limits, CPA may be subject to pipeline actions ranging from Operational Flow Orders ("OFOs") mandating storage withdrawals, to the potential confiscation by the pipeline of volumes exceeding tariff limits. CPA is also subject to maximum volumes in storage of 60 percent on July 1st and 85 percent on September 1st, requiring close monitoring of summer injection activity.

Storage Ratchets

CPA's primary storage contract, provided by TCO under the Firm Storage Service ("FSS") Rate Schedule, is subject to deliverability reductions, or ratchets, over the course of a winter season as withdrawals reduce storage inventory. CPA manages volumes in storage in the winter to assure that full deliverability is retained late enough into the winter season to cover the Design Date of the Design Day. Furthermore, in Long Range Planning of its capacity portfolio, CPA uses the Monthly Design Days, mentioned earlier in the section titled "Demand," to assure that CPA can serve firm demand on cold days in late winter, after storage withdrawal capacity has ratcheted.

For Operational Planning, which applies to the current winter season, CPA determines ratchet temperature dates based on the capacity currently under contract and 1 in 10 risk criteria. Table 5 summarizes the three pairs of ratchet temperatures and dates for winter 2025-26. The first ratchet, for example, occurs when the inventory falls below 30 percent of the SCQ. It decreases the Maximum Daily Withdrawal Quantity ("MDWQ") to 80 percent of the Maximum Daily Storage Quantity ("MDSQ").

TABLE 5

Design Temperature and Dates of the TCO Storage Ratchets

		Before the Ratchet				After the Ratchet
Ratchet		Storage inventory, as a portion of SCQ	Withdrawal capacity MDWQ, as a portion of MDSQ	Temp Deg F.	Last Date before Ratchet: 10 percent risk	Withdrawal capacity MDWQ, as a portion of MDSQ
First		>= 30 percent	100 percent	5	February 17	80 percent
Second		>= 20 percent	80 percent	12	February 27	65 percent
Third		>= 10 percent	65 percent	19	March 12	50 percent

Determination of Design Temperatures and Dates for Storage Ratchets

On the date of the first ratchet, CPA loses daily storage withdrawal capacity equal to 20 percent of its Maximum Daily Storage Quantity ("MDSQ"). After this first ratchet, CPA has enough remaining withdrawal capacity to serve firm demand if daily average temperatures are 6° Fahrenheit or warmer. CPA manages storage activity to delay the first ratchet until days with average daily temperatures of 5° Fahrenheit and colder have less than a 10 percent probability of occurrence. Based on historical temperature data since 1949, the latest occurrence of a 5° Fahrenheit or colder average day temperature, with a 1 in 10 risk of a later occurrence, is February 17th. CPA plans to maintain storage inventory above 30 percent of the Storage Contract Quantity ("SCQ") until February 17th, the design date for the first ratchet. The second and third ratchet dates are developed in a similar manner. Under all weather conditions, CPA will target inventory levels at, or above, levels shown on Table 5 until the ratchet dates shown.

The temperatures and dates associated with storage ratchets may change annually, since:

- the temperature sensitivity coefficients and Design Day Demand are based on CPA's Design Day Forecast, which is updated each year, and
- CPA's supply and capacity contracts may change.

The storage ratchet temperatures and dates are updated prior to the start of the winter heating season.

SUPPLY CONTRACTS AND DAILY BALANCING

Supply Contracts

CPA's supply objective is to secure and deliver competitively priced, reliable gas supplies for its Sales Service Customers. Given current market conditions, CPA contracts for winter season firm supply under contracts for terms from three months to five months. Having a relatively short-term duration portfolio of gas supply contracts enables CPA to adjust its portfolio to changing market conditions, and allows CPA to respond effectively to customer election of alternate suppliers under CPA's Customer CHOICE[SM] program.

CPA's purchases of firm gas supplies are primarily made under contracts priced at a published market index price. Spot gas supplies may be purchased at either a published index price or at a negotiated rate.

CPA's supply contracts must meet its reliability criteria. In the months of December through February, CPA assures the reliability of service to its firm customers by contracting for sufficient term supply, along with monthly and daily firm supply purchases, to fill its FTS capacity as required. CPA's strategy in purchasing gas supplies is to remain as flexible as possible consistent with providing reliable service in response to changing market conditions. This strategy holds true in the negotiation of nomination flexibility provisions within those firm supply contracts. Together with storage, CPA's winter purchases are sufficient to meet the human needs requirements of its Sales Service customers.

Daily Balancing

Pipeline tariffs require CPA to balance supply and demand daily at each city gate. CPA's sales and CHOICE[SM] customer demand is highly temperature sensitive and varies, or "swings," with changes in temperatures and other factors from day to day. CPA uses TCO's no-notice firm storage service to provide balancing for most of the daily differences between scheduled, flowing supply and demand for all of its customers (Sales, CHOICE[SM] and GDS). As previously noted, CPA provides GDS customers daily balancing under EBS. EBS provides a combination of firm and interruptible balancing capabilities that CPA must manage and under which GDS customers or their suppliers must function. While EBS allows GDS customers or their suppliers to deliver more gas than they consume or consume more gas than they deliver on any given day, CPA must manage these deliveries within the confines of its capacity portfolio, the EBS tariff, CHOICE[SM] balancing needs and its least cost purchase obligation for its sales customers. When conditions exist that threaten exceeding CPA contractual rights or violation of a pipeline issued operational order, CPA must impose supply restrictions or conditions upon GDS customers and their suppliers to reduce the uncertainty for CPA in regard to GDS customers supply/demand balance and avoid CPA

exceeding its contractual rights and/or violating a pipeline issued order and the attendant higher costs and penalties or from incurring higher costs for its sales and Choice service customers related to such uncertainty.

The TCO storage provides year-round balancing capability. CPA will inject excess gas supply into its storage accounts on days when customer demand is less than the volume of gas supplies scheduled to CPA's city gates. On days when customer demand exceeds the total gas supply volumes scheduled to CPA's city gates, CPA will withdraw gas from its storage accounts. While storage provides the majority of CPA's daily balancing needs, it has daily and monthly limits on both injection and withdrawal. At certain times the daily injection/withdrawal capability of storage is insufficient to meet the potential demand swings of CPA's customers, requiring CPA to increase or decrease its flowing supplies.

CPA's strategy in purchasing gas supplies is to maintain reliable service while remaining as flexible as possible consistent with changing market conditions. This strategy holds true in the negotiation of swing provisions within some firm supply contracts. This provides CPA with required flexibility, consistent with its gas purchase strategy, without incurring additional fixed costs.

Scheduling and Nominations

Along with CPA's purchase and management responsibility comes the requirement to schedule and nominate these supplies on several upstream pipelines with differing nomination requirements and penalty provisions. The operating provisions contained in the pipelines' transportation tariffs require CPA to monitor the flow of gas at its city gate delivery points. Intra-day scheduling changes to nominations can be required to avoid overrun and imbalance charges/penalties contained in the pipelines' tariffs. CPA purchases and nominates all system supply quantities. CPA monitors the supply and demand of its customers and balances any difference. To perform a portion of these responsibilities, CPA utilizes its Supervisory Control and Data Acquisition ("SCADA") system to provide constant monitoring of volumes delivered at its largest city gate delivery points.

Balancing Among Geographic Regions

CPA has a widespread service territory. CPA's service territory currently lies in eight TCO Pipeline Scheduling Points. CPA's service territory includes numerous discrete distribution systems, which are not connected by CPA transmission pipelines. Each distribution system is served by one or more city gate delivery points from interstate pipelines**.** In total CPA manages approximately 300 such city gate delivery points. CPA is able to aggregate the various supplies and demands at all TCO delivery points for billing and balancing purposes.

Supplies received directly from Equitrans are balanced with CPA's Equitrans storage service. CPA has limited ability to balance supply at Tennessee and TETCO interconnects using Operational Balancing Agreements with the pipelines involved. Similarly, receipts from National Fuel are balanced using a rolling day to day communication and adjustments between the pipeline and CPA.

Identification of Exchanges with Affiliates

The Administrative Law Judge's Recommended Decision in CPA's 2016 1307(f) proceeding, which was adopted by the PaPUC, requires that CPA identify any affiliate exchange, capacity release or off-system sale transactions in its future 1307(f) filings. CPA did not enter into any sales transactions with its affiliates.

SERVICES FOR CHOICE[SM] CUSTOMERS

CPA's CHOICE[SM] Service provides customers with the alternative to access gas commodity supplies from NGSs while maintaining the reliability these customers require.

Consistent with the Commission's December 1999 Order on CPA's restructuring, CPA functions as the Supplier of Last Resort ("SOLR") as specified under Section 2207 of the Natural Gas Choice and Competition Act. Included in the SOLR function is service to:

(1) Sales customers that have not chosen an alternative supplier;
(2) customers who have been refused service by natural gas suppliers; and
(3) customers whose CHOICE[SM] marketers fail to deliver their requirements.

To meet its SOLR obligations, CPA will utilize the capacity assets it has available under contract, including the potential recall of capacity assigned to suppliers under CPA's Customer CHOICE[SM] Program. That is, if a CHOICE[SM] marketer assigned capacity exits the Customer CHOICE[SM] Program or fails to deliver supplies to CPA as provided in its tariff, the capacity will be recalled by CPA, as needed, and utilized to maintain service to the affected customers.

CPA's Customer Assistance Program ("CAP") which previously served its low-income customers through an aggregation program is no longer active per Docket No. M-2023-3039487. These customers are now served under the General Sales Rate.

FEDERAL REGULATORY ACTIVITIES

Columbia takes an active role in Federal Energy Commission (FERC) proceedings that have the potential to impact reliability of natural gas supply to its customers and the cost associated with its delivery, whether these proceedings are pipeline specific or industry wide. Examples include pipeline rate cases, certificate applications, proposed rulemakings and policy statements. Columbia's involvement in these matters includes review, analysis, intervention, comment and collaboration. In compliance with Section 53.64 (C)(4) of the Commission's regulations.

Columbia intervenes in all FERC dockets when certificate and rate filings have the potential to impact reliability and/or cost to its customers. Please see Exhibit No. 3 for details of activities undertaken by Columbia at the FERC during 2024.

OFF-SYSTEM SALES AND CAPACITY RELEASE INCENTIVE PROGRAM

A market exists for NGDCs, such as CPA, to market unbundled and rebundled gas and capacity products to non-traditional customers. CPA's off-system sales and capacity release program provides CPA and its customers an opportunity to benefit from the unbundling of interstate pipeline services implemented by FERC Order 636.

CPA's off system sales incentives began in January 1995 and capacity release incentives began in February 1996. The results of these incentive mechanisms have been positive for both customers and CPA as interested parties and the Commission have recognized the importance of a balanced incentive in these programs. CPA continues to seek opportunities to create value for its customers under these incentive mechanisms within its least cost procurement plan.

Columbia Gas of Pennsylvania
Report Supporting Capacity
Contract Years 2025-26 Through 2028-29

February 18, 2025

CONTENTS

PURPOSE OF THE REPORT SUPPORTING CAPACITY [1]

In Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or the "Company") 2013 Rate Investigation Pursuant to 66 Pa. C.S. §1307(f), Columbia filed a Joint Petition for Settlement ("Settlement") which was executed by Columbia, the Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility Commission ("Commission"), the Office of Consumer Advocate ("OCA"), and the Office of Small Business Advocate ("OSBA"). On July 12, 2013, the ALJ issued a Recommended Decision recommending approval of the Settlement. On August 15, 2013, the Commission adopted the Recommended Decision approving the Settlement ("Order"). As part of the Settlement, Columbia agreed in future 1307(f) filings to file and provide to all parties a report related to the level of peak day capacity retained.

The relevant Settlement Terms as delineated in the Recommended Decision and approved in the Order are as follows:

D. Peak Day Capacity
c. Columbia will continue its policy to 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 Peak Demand Forecast. If the results of Columbia's Peak Day Forecast indicate that Columbia has peak day capacity in excess of this policy, Columbia agrees to reduce its peak day capacity portfolio as appropriate to the extent that any components of its portfolio are not operationally required and can contractually be reduced.

d. In future 1307(f) pre-filings, Columbia will file and provide to all parties a report identifying: (1) the level of peak day capacity retained consistent with its policy and this Stipulation and the results of the Peak Day Forecast; and (2) any adjustment to capacity taken pursuant to Columbia's policy and available contractual opportunities. If Columbia retains or renews any capacity in excess of its policy because it deems that capacity "operationally required" as the term is used in paragraph "c" above, the report will include an explanation of the reason(s) Columbia considers such retained capacity to be operationally required.

[1] The terms Peak Day and Design Day are used interchangeably herein.

Recommended Decision at p. 17.

The following report fulfills Columbia's commitment related to capacity as set forth in the Commission-approved Settlement resolving its 2013 1307(f) proceeding.

ANALYSIS AND CONCLUSION

Columbia's policy is to 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 Peak Day Forecast. Based on Columbia's 2024 Design Day Forecast, spanning the winter seasons of 2024-25 through 2028-29, Columbia's existing peak day capacity is slightly outside this policy. Growth in Columbia's firm demand is expected over the term of this forecast such that Columbia's existing available capacity equals 103.8% of projected firm demand for contract year 2028-29, the highest projected design day firm requirements in Columbia's 2024 Design Day Forecast.

In order to meet this parameter, Columbia would need to reduce its capacity by 4,800 Dth. In Exhibit 5, Table 4 submitted with Columbia's pre-filing on February 28, 2025, there was a marketed release in the amount of 5,200 Dth. After the initial filing, the large customer that has this release through October 31, 2025, indicated its intention not to continue with the release. Therefore, this release was removed in Revised Exhibit 5, Table 4, which increased the excess to 103.8%. Columbia Gas Transmission ("TCO") filed a rate case at FERC, which contains a proposal for 1/24th hourly limitations. This proposed tariff change becomes effective April 1, 2025, yet TCO's rate case will not be concluded at that time. This could have a significant impact on Columbia's capacity requirements to meet the hourly limitation. Therefore, Columbia plans to evaluate its portfolio based on the outcome of the 1/24th hourly limit pursuant to TCO's rate filing and its updated design day requirements analysis for 2025.

COLUMBIA STATEMENT NO. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2025-3053663
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF

JESSICA FISCHER

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2025

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 testified before this Commission in Columbia's 2022 1307(f) proceeding, at Docket No. R-2022-3031172, Columbia's 2023 1307(f) proceeding at Docket No. R-2023-3038630, and Columbia's 2024 1307(f) proceeding at Docket No. R-2024-3047014.

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.

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

A. Yes, they were.

Q. Are there any updates to the exhibits you are sponsoring?

A. Yes. Revised Exhibit 1-A and Revised Exhibit 1-B are submitted with this testimony to replace Exhibits 1-A and 1-B submitted in the 1307(f) pre-filing on February 28, 2025.

Q Why are revised exhibits being submitted?

A. Following the preparation of the pre-filing, it was determined that the three-year contract with a large industrial customer ending October 31, 2025, for 5,215 dth of non-recallable capacity release with Columbia Gas Transmission will not be

renewed. Please refer to Columbia witness Tina Monnig's Direct Testimony for more detail.

Q. Please describe the updates that were made to Revised Exhibit 1-B.

A. Revised Exhibit 1-B, Schedule 2 includes the projected demand costs for Columbia Gas Transmission. Beginning November 2025, the 5,215 dth release is reduced to zero since the contract with the large industrial customer will not be renewed. The Revised Schedule 2 shows projected Columbia Gas Transmission demand costs of $174,980,837, an increase of $1,260,875 from the amount originally submitted in the pre-filing. Revised Exhibit 1-B, Schedule 1, Sheets 1 and 2 also include the same increase of $1,260,875 in demand costs for the projected period. Please note that the only changes in Revised Exhibit 1-B are in Schedule 1, Sheets 1 and 2 and Schedule 2. However, the entire Revised Exhibit 1-B is attached hereto for ease of reference.

Q. Please explain the changes to Revised Exhibit 1-A.

A. Revised Exhibit 1-A has been updated to reflect the increase in projected demand costs for the application period. In Schedule 1, Sheet 1 of 2, the updated exhibit includes the Purchased Gas Demand Cost ("PGDC") rate of $0.39575 per therm and the Purchased Gas Cost ("PGC") rate of $0.74362 per therm. Both the PGDC and PGC rates have increased by $0.00271 per therm from the corresponding rates submitted in the pre-filing. Remaining rates impacted by this revision are the Standby Service Rate on Schedule 1, Sheet 2 of 2 and the Purchased Gas Demand Charge paid by Choice Customers on Schedule 3, Sheet 1 of 2. The Columbia Gas Transmission capacity assigned to marketers on Schedule 3, Sheet 2 also increased.

Please note that there were no changes to Revised Exhibit 1-A, Schedule 2, Sheet 3. However, the entire Revised Exhibit 1-A is attached hereto for ease of reference.

Q. Is the information contained within the exhibits and revised 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, 2025, for recovery of purchased gas costs?

A. Referring to Revised Exhibit No. 1–A, Schedule 1, Sheet 1 of 2, Columbia has projected an overall increase of $0.20855 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, 2025. 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 $0.20144 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 $0.03389 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 $0.04100 per therm, for an overall increase of

$0.00711 per therm. The increase to the projected gas costs and E-factor result in an overall increase of $0.20855. These changes are detailed on Revised Exhibit 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, attached to my Direct Testimony, provides the calculation of the retainage rate to be effective January 1, 2026, resulting from the three-year average ending August 31, 2024. The retainage rate will be 1.4%.

Q. Please describe Revised Exhibit 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 2025 through September 2026, divided by Columbia's total demand billing determinants for the same period.

Q. Please describe Revised Exhibit 1-A, Schedule 2.

A. Revised Exhibit 1-A, Schedule 2, Sheets 1 through 4 detail the calculation of the over/under-collection for the period of October 2025 through September 2026. This schedule shows that the rates contained in Revised Exhibit 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 Revised Exhibit 1-A, Schedule 3.

A. Revised Exhibit 1-A, Schedule 3 details the calculation of the purchased gas demand charge that is paid by customers selecting Columbia's CHOICE[SM] service. Columbia's CHOICE[SM] 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[SM] 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[SM] 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 ("TCO") and Eastern Gas Transmission and Storage, Inc. ("EGTS") pipeline capacity assignable to their NGS. The credit for the upcoming PGC period is $0.06345/therm.

Q. Please describe Revised Exhibit 1-B.

A. Revised Exhibit 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 2025 through September 2026. Revised Exhibit 1-B consists of ten schedules that detail and summarize the estimated purchased gas demand costs from TCO, 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 Revised Exhibit 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 $321,124,299.

Revised Exhibit 1-B, Schedule 1, Sheet 2 of 4 summarizes the projected demand cost from Revised Exhibit 1-B, Schedules 2 through 7 for the October 2025 through September 2026 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 Revised Exhibit 1-A to be used in the computation of rates.

Q. Please continue with your explanation of the other schedules contained in Revised Exhibit 1-B.

A. Revised Exhibit 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 Revised Exhibit 1-B		
Columbia Gas Transmission, LLC	Schedule 2	$ 174,980,837
Texas Eastern Transmission Corporation	Schedule 3	$ 4,259,788
Eastern Gas Transmission and Storage	Schedule 4	$ 3,268,627
Tennessee Gas Pipeline	Schedule 5	$ 1,321,284
National Fuel Gas Supply Corporation	Schedule 6	$ 935,076
Equitrans	Schedule 7	$ 2,766,090

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

Q. Please explain the development of the projected commodity cost reflected in Revised Exhibit 1-B.

A. The projected commodity cost shown on Revised Exhibit 1-B, Schedule 1, Sheet 3 is detailed in Schedules 8 through 10 of Revised Exhibit 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 all the city gates. The product of the projected purchases times the projected city gate purchase rates amounts to

$23,424,482. Under Columbia's Universal Service and Conservation plan order at Docket No. M-2023-3039487, as of April 4, 2024, Columbia discontinued the process of aggregate shopping for natural gas supplied to Columbia's Customer Assistance Program ("CAP") customers due to lack of interest by natural gas suppliers. Therefore, CAP customers are served by Columbia sales and CAP purchases or CAP billings were removed from Schedule 8.

Schedule 9 details the projected purchases of spot gas (Line 9 - $115,974,787) and local gas (Line 15 - $850,571). The total projected cost of these purchases is $116,825,358. In her Direct 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, TCO, and National Fuel. The total net cost of gas from storage is projected to be ($6,720,202). 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 describe Exhibit 1-C.

A. Exhibit 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 2025 through September 2025. Exhibit 1-C consists of ten schedules detailing the projected transportation and storage

capacity cost of purchases from TCO, 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 1-C.

A. Exhibit 1-C, Schedule 1, Sheet 1 sets forth the summary of the total estimated purchased gas costs, by month, for the period February 2025 through September 2025. Schedule 1, Sheet 2 summarizes the total estimated purchased gas demand costs by month and pipeline for the period February 2025 through September 2025.

Exhibit 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 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 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 the pipelines and the projected demand cost related to each:

Table 2 Projected Pipeline Demand Costs from Exhibit 1-C		
Columbia Gas Transmission, LLC	Schedule 2	$89,543,488
Texas Eastern Transmission Corporation	Schedule 3	$2,773,312
Eastern Gas Transmission and Storage	Schedule 4	$2,123,284
Tennessee Gas Pipeline	Schedule 5	$961,934
National Fuel Gas Supply Corporation	Schedule 6	$623,384
Equitrans	Schedule 7	$1,512,068

Q. Please explain the projected commodity cost development.

A. The projected commodity cost shown on Exhibit 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 $7,488,322 of projected purchased gas commodity cost. As explained previously, CAP purchases or CAP billings were removed from this schedule.

Schedule 9 provides details, for each month in the February 2025 to September 2025 period, of the total estimated purchased gas commodity costs associated with spot and local gas purchases. The projected cost of these purchases is $78,551,314 (Line 9 – $78,038,637 + Line 15 – $512,677). In her Direct

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, TCO and National Fuel to provide service to customers. The total cost of gas from storage for the eight-month period February 2025 through September 2025 is projected to be ($45,501,503), 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 Revised Exhibit 1-B, Schedule 10.

Q. Please describe the calculations contained in Exhibit 1-D.

A. Exhibit 1-D is provided in compliance with § 53.64(c)(1) of the Commission's regulations. Exhibit 1-D, Schedule 1 sets forth the historic cost of gas by type and month for the February 2024 through January 2025 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 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 1-D, Schedule 1, Sheet 1 summarizes the total costs associated with the purchases. Exhibit 1-D, Schedule 1, Sheet 2 itemizes the demand and commodity costs shown on Exhibit 1-D, Schedule 1. Exhibit 1-D, Schedule 1, Sheet 3 details the volumes associated with the purchases. Exhibit 1-D, Schedules 2 through 6 provide

additional detail on the purchases by type and month. Columbia witness Patrick Pluard is supporting Exhibits 1-D-1 through 1-D-3.

Q. Please describe Exhibit 1-E.

A. Exhibit 1-E, which consists of four schedules, sets forth the calculations supporting the experienced net over/under-collection level used in the rate recovery calculation.

Q. Please describe Exhibit 1-E, Schedule 1.

A. Exhibit 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, 2025. Schedule 1, Line 9 reflects a projected total experienced net under-collection of $16,588,185. This under-collection amount includes: 1) anticipated over/under-collection during the 2024 § 1307(f) Application Period (October 2024 through September 2025); 2) reconciliation of prior period proceeds received for off-system sales and capacity releases; and 3) reconciliation of prior period over/under-collections.

Q. Please explain the calculations on Exhibit 1-E, Schedules 2a and 2b.

A. Schedules 2a and 2b set forth the reconciliation of prior period commodity and demand costs from the 2024 PGC period of ($2,915,877) and ($12,259,132) to be collected.

Line 19 of Schedule 2a reflects the estimated prior period commodity under-collection of $464,821 that Columbia anticipates it will experience for the twelve months ending September 2025. This estimated prior period commodity under-collection is calculated by adding: 1) the over-collected commodity balance as of

September 2024 (Line 1); 2) a beginning balance adjustment (Line 2) of ($63,757); and 3) the sum of the actual and projected refunds and recoveries for the period October 2024 through September 2025 (Line 18).

Line 19 of Schedule 2b reflects the estimated prior period demand under-collection of $99,974 that Columbia anticipates it will experience for the twelve months ending September 2025. This estimated prior period demand under-collection is calculated by adding: 1) the under-collected demand balance as of September 30, 2024 (Line 1); 2) a beginning balance adjustment of $64,289; and 3) the sum of the actual and projected refunds and recoveries for the period October 2024 through September 2025 (Line 18).

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

A. The beginning balance adjustment on Schedule 2a of ($63,757) represents a commodity interest adjustment for the months of February 2024 through September 2024, decreasing the interest rate from 8.50% to 7.50% to reflect the prime interest rate as of January 31, 2025. The beginning balance adjustment of $64,289 on Schedule 2b represents a demand interest adjustment for the months February 2024 through September 2024, decreasing the interest rate from 8.50% to 7.50% to reflect the prime interest rate as of January 31, 2025.

Q. Please explain the calculations on Schedule 3.

A. Schedule 3 reflects the calculation of the estimated net - over-refunded Unified Sharing Mechanism ("USM") proceeds of $1,558, as shown on Exhibit 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 over-refunded amount of $1,558 for USM proceeds determined?

A. As indicated on Exhibit 1-E, Schedule 3, Columbia included in the E-factor a projected total credit of $2,688,223 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, 2025. This amount is allocated 100% to the PGDC (Schedule 3, Line 16). Currently, Columbia projects to pass back $2,689,781 in USM credits, based upon actual and projected volumes subject to the credit. The result is an over-refund of $1,558.

Q. Please continue with your explanation of Exhibit 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 2024 through September 2025. The monthly over/under-collection amounts for the period October 2024 through January 2025 are based on actual data. The monthly over/under-collection amounts for the period February 2025 through September 2025 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 2025 as part of Columbia's compliance filing. Exhibit 1-E, Schedule 4, Sheet 1a depicts the calculation of the commodity over/(under) collection, while Exhibit 1-E, Schedule 4, Sheet 1b depicts the calculation of the demand over/(under) collection. The estimated total under-collection of

$15,660,165, derived by combining both sheets, is carried forward to Exhibit 1-E, Schedule 1, line 6. Likewise, interest associated with the commodity and demand under collections totaling $361,667 is also calculated on Exhibit 1-E, Schedule 4, Sheets 1a and 1b respectively, and is carried to Exhibit 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 7.50% for the months of October 2024 through September 2025 for over/under collections from gas costs. This is the prime rate for commercial borrowing in effect as of January 31, 2025, 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 2025 through September 2025 period in next year's 1307(f) filing, and calculate interest for the months of October 2025 through January 2026 based on the prime interest rate for commercial borrowing for the twelve months ending January 31, 2026.

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 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 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 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 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 $127,157,356.

Q. Please explain the calculation of the EBS Option 2 revenue in Exhibit 1-E, Schedule 4, Sheet 1b, Column 2 that was used to calculate the over/under-collection.

A. Exhibit 1-E, Schedule 4, Sheet 1b, Column 2 provides a summary of 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 1-E, Schedule 4, Sheet 6. Estimated total balancing revenue for the period October 2024 through September 2025 is $614.

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 2024 through September 2025 is $2,827.

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. Please describe Exhibit 1-F, Schedule 1.

A. Schedule 1 of Exhibit 1-F constitutes Columbia's statement of over/under-collections during the twelve months ended January 31, 2025. This schedule, which is submitted in compliance with § 53.64(i)(1)(i)-(iv) of the Commission's regulations, reflects an under-collection of $16,668,909 as detailed on Schedule 1, Sheet 1. Exhibit 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 1-F, Schedule 1, Sheet 2a, reconciles the differences between the Company's total purchased gas costs, as reflected on Exhibit 1-D and the Company's financial statements, with the cost of fuel shown for PGC purposes, which appears on Exhibit 1-F, Schedule 1, Sheet 1. Exhibit 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 2025, of 9.15%.

Q. Please explain Exhibit 1-F, Schedule 2.

A. Exhibit 1-F, Schedule 2, attached to my Direct Testimony, is provided in compliance 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 2024 through January 2025, and projected costs included in the gas cost recovery components established in the 2023 1307(f) proceeding for the period February 2024 through September 2024, and in the 2024 1307(f) proceeding for the period October 2024 through January 2025.

Q. Please provide the basis for how the customers' 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 the USM rate in the pre-filing that utilizes the two-year average described above.

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

2025 1307(f) Application Filing
PGC Period October 1, 2025 - September 30, 2026

PGC Period		USM- Customer Portion	
Oct 23-Sept 24 PGC Period (Actual)	$	(3,148,097)	
Oct 24-Sept 25 PGC Period (Estimate)	$	(2,688,223)	
2 Year Average	$	(2,918,160)	
Projected Demand Sales October 1, 2025 - September 30, 2026		461,769,670	Therms
Off Systems Sales and Capacity Release Credit	$	(0.00632)	per Therm

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

§ 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 2025 1307(f) filed March 1, 2025, 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, 2025. Exhibit No. 1-F, Schedule 1, Sheet 1 indicates that Columbia was under-collected by $16,668,909 at January 31, 2025, resulting from gas costs of $182,241,159 and gas cost recoveries of $165,572,250.

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, 2024, Columbia projected gas costs for February 2024 through September 2024 of $97,137,999. Gas cost recoveries were projected at $104,116,238 for this same period of time. Accordingly, these months were projected to produce a net over-collection of $6,978,239 (Exhibit 1-A, Schedule 2, Sheet 4).

Actual gas costs for the months of February 2024 through September 2024 (2025 1307(f) Exhibit 1-F, Schedule 1, Sheet 1) totaled $90,043,777, a $7,094,221 decrease from the projections included in the January 1, 2024 PGC filing. As Columbia progressed through the 2023 1307(f) period and incrementally adjusted its recovery rates in subsequent filings, recoveries for the same period of time were recorded at $83,237,388, representing a decrease in gas cost recoveries of $20,878,850 from the January 1, 2024 PGC filing projections. In total Columbia experienced a net under-collection for the months of February 2024 through September 2024, which ended the 2023 1307(f) cycle, in the amount of $6,806,389.

As Columbia's computation of historic reconciliation period over/under collections overlaps two separate 1307(f) periods, the remaining months of October 2024 through January 2025 will now be discussed.

In the October 1, 2024 PGC filing (Exhibit 1-A,Schedule 2, Sheet 4), Columbia projected gas costs for the months of October 2024 through January 2025 to total $85,915,181 with gas cost recoveries for the same period projected at $78,550,804, for an expected under-collection of $7,364,377. Columbia's actual gas costs for the months of October 2024 through January 2025 (2025 1307(f) Exhibit 1-F, Schedule 1) were $92,197,382, which is an increase from October's gas cost projections of $6,282,201. As Columbia progressed through the 2024 1307(f) period and incrementally adjusted its recovery rates in subsequent filings, recoveries for the months of October 2024 through January 2025, were recorded at $82,334,862 (2025 1307(f) Exhibit 1-F, Schedule 1). This is an increase of $3,784,058 when compared with the October 1, 2024 PGC gas cost recovery projections. Overall, the net variance between actual gas costs and gas cost recoveries for the months of October 2024 through January 2025 resulted in a net under-collection of $9,862,520.

Together the net under-collection from the 2023 1307(f) months of February 2024 through September 2024 of $6,806,389 and the net under-collection of $9,862,520 for the 2024 1307(f) months of October 2024 through January 2025 results in a total net under-collection of $16,668,909 for the twelve month period ending January 31, 2025. The net under-collections consists of a commodity under-collection of $12,053,729 and a demand under-collection of $4,615,180.

Columbia Gas of Pennsylvania

Exhibit JF-1

	YE Aug-31	2022 Dth	2023 Dth	2024 Dth	3-Year Averages 2022 - 2024	
	Supply					
1	Raw Supply Numbers	81,533,973	78,067,318	74,753,173	78,118,155	
2	Supply Adjustment	15,825	704	-698	5,277	
3	Cumulative Adj. Supply - Including Supply Adjustments	81,549,798	78,068,022	74,752,475	78,123,432	
4						
5	ML1 Volumes	2,893,490	2,816,378	2,976,033	2,895,300	
6	Cumulative Adj. Supply Including Supply Adj. Less ML1	78,656,308	75,251,644	71,776,442	75,228,132	
7	Excess Pressure Volumes	27,068,846	24,520,795	24,227,441	25,272,361	
8	Cumulative Adj. Supply Including Supply Adj. Less Excess Pressure and ML1	51,587,462	50,730,849	47,549,001	49,955,771	
	Consumption					
9	Residential	33,025,648	31,250,450	29,052,614	31,109,571	
10	Commercial	23,344,368	22,671,129	21,582,024	22,532,507	
11	Industrial	23,582,631	22,937,550	22,850,927	23,123,703	
12	Other	3,169	2,439	3,221	2,943	
13	Electric Gen.	470,912	404,820	387,926	421,219	
14	Company Use	119,026	133,876	133,564	128,822	
15	Subtotal Consumption	80,545,754	77,400,264	74,010,276	77,318,765	
16	ML1 Volumes	2,893,490	2,816,378	2,976,033	2,895,300	
17	Excess Pressure	26,800,838	24,278,015	23,987,565	25,022,139	
18	Total Consumption - Includes Company Use but not ML1 (18 = 15 - 16)	77,652,264	74,583,886	71,034,243	74,423,464	
19	Total Consumption-Includes Company Use Less ML1 and Excess Pressure (19 = 18 -17)	50,851,426	50,305,871	47,046,678	49,401,325	
	Retainage					
19	Retainage-Includes Company Use Less ML1	1,123,070	801,634	875,763	933,489	
20	Rate (20 = 19 / 6)	1.4%	1.1%	1.2%	1.1%	
21	Retainage - Includes Company Use but not ML1 nor Excess Pressure	855,062	558,854	635,887	683,268	
22	Rate (22 = 21 / 8)	1.7%	1.1%	1.3%	1.4%	(1)

(1) Rate to be in effect as of January 1, 2026.

COLUMBIA GAS OF PENNSYLVANIA, INC.
COMPUTATION OF CHANGE IN RATE PURSUANT TO SECTION 1307(f)
APPLICATION PERIOD: OCTOBER, 2025 THROUGH SEPTEMBER, 2026

Line No.	Description		Amount	
			(1)	
1	Purchased Gas Commodity Cost		$	
2	Commodity Cost of Gas (Exhibit 1-B, Schedule 1)		133,892,597	
3	Projected tariff sales for the twelve billing periods of			
4	October, 2025 through September, 2026		384,887,844	Therms
5	PGCC (Line 2/Line 4)		0.34787	
6	Commodity (Over)/Under Collection			
7	Commodity E-Factor			
8	(Exhibit No. 1-E)		11,752,289	
9	Projected sales for the twelve billing periods of			
10	October, 2025 through September, 2026		384,887,844	Therms
11	Commodity E-Factor (Line 8/ Line 10)		0.03053	
12	Purchased Gas Demand Cost			
13	Demand cost of gas (Exhibit 1-B, Schedule 1)		187,231,702	
14	Less: Purchased Gas Demand recovered under Rate SS			
15	(Exhibit 1-A, Schedule 2, Sheet 2)		1,568,510	
16	Less: Purchased Gas Demand Cost allocated to Rates LTS, STS,			
17	SGS-TS and MLS (Exh 1-A, Sch 2, Page 3)		0	
18	Subtotal (Line 13 - Line 15 - Line 17)		185,663,192	
19	Projected sales for the twelve billing periods of			
20	October, 2025 through September, 2026	1_/	461,769,670	Therms
21	PGDC Rate prior to Capacity Release Credit (Line 18 / Line 20)		0.40207	
22	Off System Sales and Capacity Release Credit		(0.00632)	
23	PGDC Rate		0.39575	
24	Demand (Over)/Under Collection			
25	Demand E- Factor			
26	(Exhibit No. 1-E)		4,835,896	
27	Projected sales for the twelve billing periods of			
28	October, 2025 through September, 2026	1_/	461,769,670	Therms
29	Demand E-Factor (Line 26 / Line 28)		0.01047	
30	Total Purchased Gas Cost			
31	PGCC Rate (Line 5)		0.34787	
32	PGDC Rate (Line 23)		0.39575	
33	PGC Rate		0.74362	
34	Currently effective PGC		0.54218	
35	Increase (Decrease) in PGC		0.20144	
36	Net (Over) Under Collection			
37	Commodity E-Factor (Line 11)		0.03053	
38	Demand E-Factor (Line 29)		0.01047	
39	E-Factor		0.04100	
40	Currently effective E-Factor		0.03389	
41	Increase (Decrease) in E-Factor		0.00711	
42	PGC Rate		0.74362	
43	E-Factor		0.04100	
44	Total Rate		0.78462	
45	Currently effective Rate		0.57607	
46	Increase (Decrease) in Rate		0.20855	

1_/ Includes 76,881,826 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, 2025 THROUGH SEPTEMBER, 2026

Line No.	Description	Detail (1)		Total (2)
1	Total estimated demand charges for the period			
2	October, 2025 through September, 2026	187,231,702		
3	Estimated Demand Quantity (Therms) 1_/	81,748,680		
4	Daily purchased gas demand rate (Line 2 / line 3)	$2.29033	per Therm	
5	Daily purchased gas demand (Therms)	684,840	Therms	
6	Daily purchased gas demand rate per Therm	$2.29033		
7	Total rate SS Daily Demand Cost to be			
8	Recovered (Line 5 x Line 6)			$1,568,510

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, 2025 THROUGH SEPTEMBER, 2026

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 - 2025	9,775,315	0.34787	3,400,539	11,979,409	0.40207	4,816,561	8,217,100
2	November	24,763,825	0.34787	8,614,592	29,969,901	0.40207	12,049,998	20,664,590
3	December	55,607,708	0.34787	19,344,253	66,476,243	0.40207	26,728,103	46,072,356
4	January - 2026	73,853,214	0.34787	25,691,318	88,319,988	0.40207	35,510,818	61,202,136
5	February	74,502,535	0.34787	25,917,197	88,997,761	0.40207	35,783,330	61,700,527
6	March	60,891,122	0.34787	21,182,195	72,654,142	0.40207	29,212,051	50,394,246
7	April	39,756,897	0.34787	13,830,232	47,419,688	0.40207	19,066,034	32,896,266
8	May	18,968,141	0.34787	6,598,447	22,992,666	0.40207	9,244,661	15,843,108
9	June	9,346,526	0.34787	3,251,376	11,408,264	0.40207	4,586,921	7,838,297
10	July	6,051,286	0.34787	2,105,061	7,482,318	0.40207	3,008,416	5,113,477
11	August	5,316,033	0.34787	1,849,288	6,614,751	0.40207	2,659,593	4,508,881
12	September	6,055,242	0.34787	2,106,437	7,454,539	0.40207	2,997,246	5,103,683
13	Total	384,887,844		133,890,935	461,769,670		185,663,732	319,554,667

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, 2025 THROUGH SEPTEMBER, 2026

Line No.	Month	Daily Purchased Gas Demand Quantity	Daily Gas Demand Rate	Daily Purchased Gas Demand Revenue
		(1)	(2)	(3=1x2)
		Therms	$/Therm	$
1	October - 2025	57,070	2.29033	130,709
2	November	57,070	2.29033	130,709
3	December	57,070	2.29033	130,709
4	January - 2026	57,070	2.29033	130,709
5	February	57,070	2.29033	130,709
6	March	57,070	2.29033	130,709
7	April	57,070	2.29033	130,709
8	May	57,070	2.29033	130,709
9	June	57,070	2.29033	130,709
10	July	57,070	2.29033	130,709
11	August	57,070	2.29033	130,709
12	September	57,070	2.29033	130,709
13	Total	684,840		1,568,510

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PROJECTED SALES QUANTITIES AND REVENUES FOR THE PERIOD
SALES AT BANKING AND BALANCING RATES
OCTOBER, 2025 THROUGH SEPTEMBER, 2026

Line No.	Month	Lg. Quantity GDS Deliveries	Rate	Revenue	Sm. Quantity GDS Deliveries	Rate	Revenue	Total Trans. Revenue
		(1) Therms	(2) $/Therm	(3=1x2) $	(4) Therms	(5) $/Therm	(6=4x5) $	(7=3+6) $
1	October - 2025	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 - 2026	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 2025 1307(f) PERIOD
OCTOBER, 2025 THROUGH SEPTEMBER, 2026

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 - 2025	3,400,539	4,896,179	(1,495,640)	4,947,270	17,607,409	(12,660,139)	(14,155,778)
2	November	8,614,592	13,054,461	(4,439,869)	12,180,707	17,892,763	(5,712,056)	(10,151,924)
3	December	19,344,253	24,522,438	(5,178,185)	26,858,812	17,992,583	8,866,229	3,688,044
4	January - 2026	25,691,318	31,379,375	(5,688,057)	35,641,527	17,992,583	17,648,944	11,960,887
5	February	25,917,197	25,707,742	209,455	35,914,039	17,992,583	17,921,456	18,130,911
6	March	21,182,195	17,576,816	3,605,380	29,342,760	17,992,583	11,350,177	14,955,557
7	April	13,830,232	8,617,737	5,212,495	19,196,743	13,373,533	5,823,210	11,035,705
8	May	6,598,447	3,536,942	3,061,505	9,375,370	13,277,533	(3,902,163)	(840,658)
9	June	3,251,376	1,228,170	2,023,206	4,717,630	13,277,533	(8,559,903)	(6,536,697)
10	July	2,105,061	1,160,767	944,294	3,139,125	13,277,533	(10,138,408)	(9,194,113)
11	August	1,849,288	861,832	987,456	2,790,302	13,277,533	(10,487,231)	(9,499,775)
12	September	2,106,437	1,350,139	756,298	3,127,955	13,277,533	(10,149,578)	(9,393,280)
13	Total	133,890,935	133,892,597	(1,663)	187,232,242	187,231,702	540	(1,122)

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, 2026

$187,231,702		1. Projected Demand Costs Oct. 2025 through Sept. 2026 (Exh. 1-B, Sch. 1)
(1,568,510)		1a. Less Purchased Gas Demand Costs Recovered Under Rate SS (Exhibit 1-A, Schedule 1, Sheet 2)
0		1b. Less Purchased Gas Demand Allocated to Rates LTS, STS, SGS-TS, and MLS
4,835,896		1c. Experienced Demand Net Under/(Over) Collection (Exhibit No. 1-E)
$190,499,088		2. Total Adjusted Demand Costs per 1307(f) Filing (1) + (1a) + (1b) + (1c)
$256.88	per Dth	3. Unit FT Demand Charge Per Dth of TCO/EGTS capacity the marketer would pay TCO and EGTS. (Exhibit 1-A, Schedule 3, Sheet 2)
46,177	MMDth	4. Projected Sales & Choice Requirements for 12 billing periods of October, 2025 through September, 2026
46,736	MMDth	5. Projected Sales & Choice Requirements 12 months ended September 2026, including Unaccounted For @ 1.2%
21,755	MMDth	6. Annual Injections and Withdrawals, Normal Weather
1	Dth	7a. Quantity Delivered to the Customer
1.2%		7b. Unaccounted-for & Co. Use Factor from Volume Balancing System
1.0121	Dth	7c. Quantity Delivered to the City Gate. (7a)/(1-7b)
$4.1254	per Dth	8. Unit Demand Charge: (2) / (4)
($0.0632)	per Dth	9. OSS and Capacity Release Credit
0.0028	Dth	10. Average Daily FT Delivery: (7c) / 365 days
$0.7193	per Dth	11. Annual Demand Charge for the Assigned FT Capacity payable to the pipeline(s): (3) X (10)
$3.4061	per Dth	12. Annual Demand Charge for other capacity that CPA retains (8) - (11)
0.4711	Dth	13. Quantity Injected and Withdrawn to Deliver 1 Dth to the Customer: (6) / (4)
$0.0157		14a. Injection Charge @ $0.0333/Dth
$0.0092		14b. FSS Shrinkage @ 0.550% for gas at $3.5359/Dth
$0.0157		14c. Withdrawal Charge @ $0.0333/Dth
$0.0088		14d. SST Commodity Charge @ $0.0186/Dth
$0.0354		14e. SST retention @ 2.128% for gas at $3.5359/Dth
$0.0848	per Dth	14f. Total Annual Variable Storage Costs
		15. Credit to Purchased Gas Demand Charge for the CHOICE Customer:
$0.7193	per Dth	15a. For Demand Cost Paid to Pipelines: = (11)
($0.0848)	per Dth	15b. Less Storage Costs: = (14f)
$0.6345	per Dth	15c. Net Credit: (15a) + (15b)
$0.06345	per Therm	15d. Per Therm: (15c)/10 - Capacity Assignment Factor
$3.4277	per Dth	16. Purchased Gas Demand Charge Paid By the CHOICE Customer: (8)+(9) - (15c)
$0.34277	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	134,496	5,000 1/	
3. Projected Demand Costs			
4. Annual Demand Cost 2/	$35,474,771	$357,732	
4a. Monthly Billing Determinants	134,496	5,000	
4b. Annual Demand Charge (4/ 4a)	$263.76	$71.55	
4c. Monthly Demand Charge (4b / number of months)	$21.980	$5.963	
Allocation Capacity and Costs.			
5. Retained Volume:	1.0000	1.0000	
6. Number of Months	12	12	
7. Capacity Allocation	0.9642 3/	0.0358 4/	
8. Unit Annual Cost of City Gate Capacity: (4c) x (5) x (6) x (7) $/Dth	$254.32	$2.56	$256.88

Notes:

1/ Non-storage EGTS FT capacity
2/ Projected demand costs for the period 12 months ended September, 2025.
3/ 134,496/(134,496+5,000) = 0.9642
4/ 5,000/(134,496+5,000) = 0.0358

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
For the Period October 2025 Through September 2026

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 September	Total
1	Total Quantity													
2	DTH	1,731,000	4,417,000	6,934,000	8,615,000	7,314,000	5,647,000	2,600,000	1,036,000	345,000	313,000	282,000	433,000	39,667,000
3	Total Demand Costs	17,607,409	17,892,763	17,992,583	17,992,583	17,992,583	17,992,583	13,373,533	13,277,533	13,277,533	13,277,533	13,277,533	13,277,533	187,231,702
4	Total Commodity Costs	4,896,179	13,054,461	24,522,438	31,379,375	25,707,742	17,576,816	8,617,737	3,536,942	1,228,170	1,160,767	861,832	1,350,139	133,892,597
5	Total Estimated Gas Costs (Line 5 = Line 3 + Line 4)	22,503,588	30,947,224	42,515,021	49,371,958	43,700,325	35,569,399	21,991,270	16,814,475	14,505,703	14,438,300	14,139,365	14,627,672	321,124,299

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Demand Costs

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
1	Columbia Gas Transmission	16,650,914	16,765,539	16,765,539	16,765,539	16,765,539	16,765,539	12,417,038	12,417,038	12,417,038	12,417,038	12,417,038	12,417,038	174,980,837
2	Texas Eastern Transmission	321,709	321,709	421,529	421,529	421,529	421,529	321,709	321,709	321,709	321,709	321,709	321,709	4,259,788
3	Eastern Gas Transmission and Storage	254,996	296,731	296,731	296,731	296,731	296,731	254,996	254,996	254,996	254,996	254,996	254,996	3,268,627
4	Tennessee Gas	110,107	110,107	110,107	110,107	110,107	110,107	110,107	110,107	110,107	110,107	110,107	110,107	1,321,284
5	National Fuel Gas	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	935,076
6	Equitrans	216,760	345,754	345,754	345,754	345,754	345,754	216,760	120,760	120,760	120,760	120,760	120,760	2,766,090
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	17,607,409	17,892,763	17,992,583	17,992,583	17,992,583	17,992,583	13,373,533	13,277,533	13,277,533	13,277,533	13,277,533	13,277,533	187,231,702

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Commodity Costs

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
1	Term	227,196	1,919,945	5,873,102	6,659,450	5,596,474	2,464,956	267,638	85,431	82,740	86,785	86,806	73,959	23,424,482
2	Spot	9,432,849	1,794,702	11,409,469	12,207,507	9,193,514	1,479,284	17,519,317	13,221,632	10,977,853	10,801,421	9,675,353	8,261,886	115,974,787
3	Local	59,248	64,453	81,431	93,056	78,894	78,494	66,547	67,881	65,171	68,528	67,837	59,031	850,571
4	Storage	(4,364,165)	9,241,701	7,403,956	12,819,982	11,012,440	13,385,122	(9,192,205)	(9,838,002)	(9,830,934)	(9,769,567)	(8,764,884)	(6,847,397)	(4,743,953)
5	Financial Hedges	(458,950)	33,660	(245,520)	(400,620)	(173,580)	168,960	(43,560)	0	(66,660)	(26,400)	(203,280)	(197,340)	(1,613,290)
6	Total Commodity Cost	4,896,179	13,054,461	24,522,438	31,379,375	25,707,742	17,576,816	8,617,737	3,536,942	1,228,170	1,160,767	861,832	1,350,139	133,892,597

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Commodity Quantities

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 September	Total
	Term													
1	Total-DTH	90,000	666,000	1,495,000	1,496,000	1,351,000	687,000	87,000	29,000	28,000	29,000	29,000	28,000	6,015,000
	Spot													
2	Total-DTH	3,150,000	599,000	2,877,000	2,721,000	2,184,000	406,000	5,339,000	4,081,000	3,294,000	3,239,000	2,891,000	2,611,000	33,392,000
	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	(1,531,000)	3,131,000	2,540,000	4,376,000	3,759,000	4,532,000	(2,847,000)	(3,096,000)	(2,998,000)	(2,977,000)	(2,660,000)	(2,227,000)	2,000
	Total - All Sources													
5	Total-DTH	1,731,000	4,417,000	6,934,000	8,615,000	7,314,000	5,647,000	2,600,000	1,036,000	345,000	313,000	282,000	433,000	39,667,000

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Columbia Gas Transmission, LLC

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 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	0	0	0	0	0	0	0	0	0	0	0	
3	Net Billing Determinant - Dth	129,716	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	
4	Demand Rate	21.9800	21.9800	21.9800	21.9800	21.9800	21.9800	21.9800	21.9800	21.9800	21.9800	21.9800	21.9800	
5	Demand Cost	2,851,158	2,965,783	2,965,783	2,965,783	2,965,783	2,965,783	2,965,783	2,965,783	2,965,783	2,965,783	2,965,783	2,965,783	35,474,771
	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	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	
8	Demand Cost	2,556,708	2,556,708	2,556,708	2,556,708	2,556,708	2,556,708	2,556,708	2,556,708	2,556,708	2,556,708	2,556,708	2,556,708	30,680,496
	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	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	
11	Demand Cost	2,546,046	2,546,046	2,546,046	2,546,046	2,546,046	2,546,046	2,546,046	2,546,046	2,546,046	2,546,046	2,546,046	2,546,046	30,552,552
	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	21.9780	21.9780	21.9780	21.9780	21.9780	21.9780	21.9780	21.9780	21.9780	21.9780	21.9780	21.9780	
14	Demand Cost	8,697,002	8,697,002	8,697,002	8,697,002	8,697,002	8,697,002	4,348,501	4,348,501	4,348,501	4,348,501	4,348,501	4,348,501	78,273,018
15	Total TCO Demand Cost	16,650,914	16,765,539	16,765,539	16,765,539	16,765,539	16,765,539	12,417,038	12,417,038	12,417,038	12,417,038	12,417,038	12,417,038	174,980,837

(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.

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 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	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	
3	Demand Cost	27,701	27,701	27,701	27,701	27,701	27,701	27,701	27,701	27,701	27,701	27,701	27,701	332,412
	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	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	8.9880	
6	Demand Cost	105,636	105,636	105,636	105,636	105,636	105,636	105,636	105,636	105,636	105,636	105,636	105,636	1,267,632
	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	24.6681	24.6681	24.6681	24.6681	24.6681	24.6681	24.6681	24.6681	24.6681	24.6681	24.6681	24.6681	
9	Demand Cost	57,773	57,773	57,773	57,773	57,773	57,773	57,773	57,773	57,773	57,773	57,773	57,773	693,276
	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	20.9673	20.9673	20.9673	20.9673	20.9673	20.9673	20.9673	20.9673	20.9673	20.9673	20.9673	20.9673	
12	Demand Cost	104,836	104,836	104,836	104,836	104,836	104,836	104,836	104,836	104,836	104,836	104,836	104,836	1,258,032
	CDS - Chambersburg													
13	Billing Determinant-Dth	158	158	158	158	158	158	158	158	158	158	158	158	
14	Demand Rate	24.6801	24.6801	24.6801	24.6801	24.6801	24.6801	24.6801	24.6801	24.6801	24.6801	24.6801	24.6801	
15	Demand Cost	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	46,788
	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	9.9820	9.9820	9.9820	9.9820	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
18	Demand Cost	0	0	99,820	99,820	99,820	99,820	0	0	0	0	0	0	399,280
	FT1-MX													
19	Billing Determinant-Dth	100	100	100	100	100	100	100	100	100	100	100	100	
20	Demand Rate	1.7090	1.7090	1.7090	1.7090	1.7090	1.7090	1.7090	1.7090	1.7090	1.7090	1.7090	1.7090	
21	Demand Cost	171	171	171	171	171	171	171	171	171	171	171	171	2,052
	FT1-M2													
22	Billing Determinant-Dth	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	
23	Demand Rate	6.7790	6.7790	6.7790	6.7790	6.7790	6.7790	6.7790	6.7790	6.7790	6.7790	6.7790	6.7790	
24	Demand Cost	21,693	21,693	21,693	21,693	21,693	21,693	21,693	21,693	21,693	21,693	21,693	21,693	260,316
25	Total TETCO Demand Cost	321,709	321,709	421,529	421,529	421,529	421,529	321,709	321,709	321,709	321,709	321,709	321,709	4,259,788

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 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	2.6720	2.6720	2.6720	2.6720	2.6720	2.6720	2.6720	2.6720	2.6720	2.6720	2.6720	2.6720	
3	Demand Cost	64,128	64,128	64,128	64,128	64,128	64,128	64,128	64,128	64,128	64,128	64,128	64,128	769,536
	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	5.9622	5.9622	5.9622	5.9622	5.9622	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
9	Demand Cost	0	35,773	35,773	35,773	35,773	35,773	0	0	0	0	0	0	178,865
	FT													
10	Billing Determinant-Dth	23,916	24,916	24,916	24,916	24,916	24,916	23,916	23,916	23,916	23,916	23,916	23,916	
11	Total-DTH	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	
12	Demand Cost	142,592	148,554	148,554	148,554	148,554	148,554	142,592	142,592	142,592	142,592	142,592	142,592	1,740,914
13	Total DTI Demand Cost	254,996	296,731	296,731	296,731	296,731	296,731	254,996	254,996	254,996	254,996	254,996	254,996	3,268,627

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 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	4.3590	4.3590	4.3590	4.3590	4.3590	4.3590	4.3590	4.3590	4.3590	4.3590	4.3590	4.3590	
6	Demand Cost	33,128	33,128	33,128	33,128	33,128	33,128	33,128	33,128	33,128	33,128	33,128	33,128	397,536
7	Total Tennessee Gas Demand Cost	110,107	110,107	110,107	110,107	110,107	110,107	110,107	110,107	110,107	110,107	110,107	110,107	1,321,284

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2025 October $	2025 November $	2025 December $	2026 January $	2026 February $	2026 March $	2026 April $	2026 May $	2026 June $	2026 July $	2026 August $	2026 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	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	
3	Demand Cost	26,405	26,405	26,405	26,405	26,405	26,405	26,405	26,405	26,405	26,405	26,405	26,405	316,860
	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	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	
6	Demand Cost	27,946	27,946	27,946	27,946	27,946	27,946	27,946	27,946	27,946	27,946	27,946	27,946	335,352
	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	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	
9	Demand Cost	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	94,044
	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	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	
12	Demand Cost	15,735	15,735	15,735	15,735	15,735	15,735	15,735	15,735	15,735	15,735	15,735	15,735	188,820
13	Total National Fuel Demand Cost	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	935,076

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Equitrans

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	Equitrans													
	FTS													
1	Billing Determinant-Dth	27,095	26,708	26,708	26,708	26,708	26,708	27,095	15,095	15,095	15,095	15,095	15,095	
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	216,760	213,664	213,664	213,664	213,664	213,664	216,760	120,760	120,760	120,760	120,760	120,760	2,105,640
	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	216,760	345,754	345,754	345,754	345,754	345,754	216,760	120,760	120,760	120,760	120,760	120,760	2,766,090

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Term Contracts

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 September	Total
	TERM													
	COLUMBIA TRANSMISSION													
1	Quantity - DTH	0	0	577,000	577,000	522,000	0	0	0	0	0	0	0	1,676,000
2	Rate-$/DTH	0.0000	0.0000	3.8005	4.3404	4.0491	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
3	Cost-$	0	0	2,192,889	2,504,411	2,113,630	0	0	0	0	0	0	0	6,810,930
	TEXAS EASTERN													
4	Quantity - DTH	90,000	666,000	686,000	687,000	620,000	687,000	87,000	29,000	28,000	29,000	29,000	28,000	3,666,000
5	Rate-$/DTH	2.5244	2.8828	3.6265	4.2236	3.9225	3.5880	3.0763	2.9459	2.9550	2.9926	2.9933	2.6414	
6	Cost-$	227,196	1,919,945	2,487,779	2,901,613	2,431,950	2,464,956	267,638	85,431	82,740	86,785	86,806	73,959	13,116,798
	TENNESSEE GAS PIPELINE													
7	Quantity - DTH	0	0	232,000	232,000	209,000	0	0	0	0	0	0	0	673,000
8	Rate-$/DTH	0.0000	0.0000	5.1398	5.4027	5.0282	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
9	Cost-$	0	0	1,192,434	1,253,426	1,050,894	0	0	0	0	0	0	0	3,496,754
10	Total - DTH	90,000	666,000	1,495,000	1,496,000	1,351,000	687,000	87,000	29,000	28,000	29,000	29,000	28,000	6,015,000
11	Total Term Commodity													
12	Cost-$	227,196	1,919,945	5,873,102	6,659,450	5,596,474	2,464,956	267,638	85,431	82,740	86,785	86,806	73,959	23,424,482

Revised Exhibit 1-B
Schedule 9
Sheet 1 of 1

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 September	Total
	SPOT													
	Base													
1	Quantity - DTH	1,718,000	401,000	2,717,000	2,645,000	2,177,000	374,000	3,339,000	3,178,000	2,795,000	1,154,000	1,128,000	1,245,000	22,871,000
2	Rate-$/DTH	3.2755	3.0474	3.9850	4.4906	4.2100	3.6418	3.3266	3.2635	3.3982	3.6602	3.6959	3.5343	
3	Cost-$	5,627,309	1,222,007	10,827,245	11,877,637	9,165,170	1,362,033	11,107,517	10,371,403	9,497,969	4,223,871	4,168,975	4,400,204	83,851,340
	Swing													
4	Quantity - DTH	1,432,000	198,000	160,000	76,000	7,000	32,000	2,000,000	903,000	499,000	2,085,000	1,763,000	1,366,000	10,521,000
5	Rate-$/DTH	2.6575	2.8924	3.6389	4.3404	4.0491	3.6641	3.2059	3.1564	2.9657	3.1547	3.1233	2.8270	
6	Cost-$	3,805,540	572,695	582,224	329,870	28,344	117,251	6,411,800	2,850,229	1,479,884	6,577,550	5,506,378	3,861,682	32,123,447
7	Total - DTH	3,150,000	599,000	2,877,000	2,721,000	2,184,000	406,000	5,339,000	4,081,000	3,294,000	3,239,000	2,891,000	2,611,000	33,392,000
8	Total Spot													
9	Commodity Cost - $	9,432,849	1,794,702	11,409,469	12,207,507	9,193,514	1,479,284	17,519,317	13,221,632	10,977,853	10,801,421	9,675,353	8,261,886	115,974,787
	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-$/DTH	2.6931	3.0692	3.7014	4.2298	3.9447	3.5679	3.1689	3.0855	3.1034	3.1149	3.0835	2.8110	
12	Cost-$	59,248	64,453	81,431	93,056	78,894	78,494	66,547	67,881	65,171	68,528	67,837	59,031	850,571
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 - $	59,248	64,453	81,431	93,056	78,894	78,494	66,547	67,881	65,171	68,528	67,837	59,031	850,571

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs

Storage

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 September	Total
	EASTERN - GSS													
1	Injections - DTH	(228,000)	0	0	0	0	0	(278,000)	(256,000)	(256,000)	(256,000)	(256,000)	(256,000)	(1,786,000)
2	Injection Rate - $/Dth	2.9796	2.9386	3.9518	4.4728	4.1825	3.6078	3.2777	3.2369	3.3281	3.3303	3.3413	3.1560	
3	Withdrawals - DTH	0	18,000	365,000	550,000	468,000	391,000	0	0	0	0	0	0	1,792,000
4	Withdrawl Rate - $/Dth	2.9461	2.9461	2.9461	2.9461	2.9461	2.9461	3.0733	3.1241	3.1724	3.2026	3.2232	3.2156	
5	Cost-$	(679,349)	53,030	1,075,327	1,620,355	1,378,775	1,151,925	(911,201)	(828,646)	(851,994)	(852,557)	(855,373)	(807,936)	(507,644)
6	Injection Rate $/Dth	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	
7	Withdrawl Rate $/Dth	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	
8	Cost - $	9,188	464	9,417	14,190	12,074	10,088	11,203	10,317	10,317	10,317	10,317	10,317	118,209
	EQUITRANS - SS													
9	Injections - DTH	(206,000)	0	0	0	0	0	(294,000)	(226,000)	(226,000)	(224,000)	(226,000)	(226,000)	(1,628,000)
10	Injection Rate - $/Dth	2.9796	2.9386	3.9518	4.4728	4.1825	3.6078	3.2777	3.2369	3.3281	3.3303	3.3413	3.1560	
11	Withdrawals - DTH	0	382,000	287,000	306,000	306,000	347,000	0	0	0	0	0	0	1,628,000
12	Withdrawl Rate - $/Dth	2.9461	2.9461	2.9461	2.9461	2.9461	2.9461	3.0733	3.1241	3.1724	3.2026	3.2232	3.2156	
13	Cost-$	(613,798)	1,125,410	845,531	901,507	901,507	1,022,297	(963,644)	(731,539)	(752,151)	(745,987)	(755,134)	(713,256)	(479,257)
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	(2,351,000)	(2,948,000)	(2,948,000)	(2,948,000)	(2,636,000)	(2,162,000)	(17,310,000)
17	Injection Rate - $/Dth	2.9796	2.9386	3.9518	4.4728	4.1825	3.6078	3.2777	3.2369	3.3281	3.3303	3.3413	3.1560	
18	Withdrawals - DTH	0	2,879,000	2,411,000	4,312,000	3,607,000	4,100,000	0	0	0	0	0	0	17,309,000
19	Withdrawl Rate - $/Dth	2.9461	2.9461	2.9461	2.9461	2.9461	2.9461	3.0733	3.1241	3.1724	3.2026	3.2232	3.2156	
20	Cost-$	(3,924,133)	8,481,822	7,103,047	12,703,583	10,626,583	12,079,010	(7,705,873)	(9,542,381)	(9,811,239)	(9,817,724)	(8,807,667)	(6,823,272)	(5,438,244)
21	Inject/With. Rate $/DTH	0.0333	0.0333	0.0333	0.0333	0.0333	0.0333	0.0333	0.0333	0.0333	0.0333	0.0333	0.0333	
22	Cost - $	43,856	95,871	80,286	143,590	120,113	136,530	78,288	98,168	98,168	98,168	87,779	71,995	1,152,812
	NATIONAL FUEL - ESS													
23	Injections - DTH	(15,000)	0	0	0	0	0	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(105,000)
24	Injection Rate - $/Dth	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.2777	3.2369	3.3281	3.3303	3.3413	3.1560	
25	Withdrawals - DTH	0	26,000	14,000	17,000	19,000	29,000	0	0	0	0	0	0	105,000
26	Withdrawl Rate - $/Dth	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.0733	3.1241	3.1724	3.2026	3.2232	3.2156	
27	Cost-$	0	0	0	0	0	0	(49,166)	(48,554)	(49,922)	(49,955)	(50,120)	(47,340)	(295,057)
28	Inject/With. Rate $/DTH	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	
29	Cost - $	594	1,030	554	673	752	1,148	594	594	594	594	594	594	8,315
30	Quantity - DTH	(1,766,000)	3,305,000	3,077,000	5,185,000	4,400,000	4,867,000	(2,938,000)	(3,445,000)	(3,445,000)	(3,443,000)	(3,133,000)	(2,659,000)	5,000
31	Total Purchase Cost	(5,217,280)	9,660,262	9,023,905	15,225,445	12,906,865	14,253,232	(9,629,884)	(11,151,120)	(11,465,306)	(11,466,223)	(10,468,294)	(8,391,804)	(6,720,202)
32	Total Inject/With. Cost	53,638	97,365	90,257	158,453	132,939	147,766	90,085	109,079	109,079	109,079	98,690	82,906	1,279,336

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Storage Transportation Charges

Line No.	Description	2025 October	2025 November	2025 December	2026 January	2026 February	2026 March	2026 April	2026 May	2026 June	2026 July	2026 August	2026 September	Total
	TCO - SST													
1	Injections - DTH	(1,317,000)	0	0	0	0	0	(2,351,000)	(2,948,000)	(2,948,000)	(2,948,000)	(2,636,000)	(2,162,000)	(17,310,000)
2	Withdrawals - DTH	0	2,879,000	2,411,000	4,312,000	3,607,000	4,100,000	0	0	0	0	0	0	17,309,000
3	Trans. Chrg. $/Dth	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	
4	Cost-$	24,496	53,549	44,845	80,203	67,090	76,260	43,729	54,833	54,833	54,833	49,030	40,213	643,914
	EASTERN - GSS													
5	Injections - DTH	(228,000)	0	0	0	0	0	(278,000)	(256,000)	(256,000)	(256,000)	(256,000)	(256,000)	(1,786,000)
6	Withdrawals - DTH	0	18,000	365,000	550,000	468,000	391,000	0	0	0	0	0	0	1,792,000
7	Trans. Chrg. $/Dth	0.0186	0.0135	0.0135	0.0135	0.0135	0.0135	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	
8	Cost-$	4,241	243	4,928	7,425	6,318	5,279	5,171	4,762	4,762	4,762	4,762	4,762	57,415
	EQUITRANS - SS													
9	Injections - DTH	(206,000)	0	0	0	0	0	(294,000)	(226,000)	(226,000)	(224,000)	(226,000)	(226,000)	(1,628,000)
10	Withdrawals - DTH	0	382,000	287,000	306,000	306,000	347,000	0	0	0	0	0	0	1,628,000
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	(15,000)	0	0	0	0	0	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(105,000)
14	Withdrawals - DTH	0	26,000	14,000	17,000	19,000	29,000	0	0	0	0	0	0	105,000
15	Trans. Chrg. $/Dth	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	
16	Cost-$	387	671	361	439	490	748	387	387	387	387	387	387	5,418
17	Total Storage - DTH	(1,766,000)	3,305,000	3,077,000	5,185,000	4,400,000	4,867,000	(2,938,000)	(3,445,000)	(3,445,000)	(3,443,000)	(3,133,000)	(2,659,000)	5,000
18	Total EUB - DTH	235,000	(174,000)	(537,000)	(809,000)	(641,000)	(335,000)	91,000	349,000	447,000	466,000	473,000	432,000	(3,000)
19	Total DTH	(1,531,000)	3,131,000	2,540,000	4,376,000	3,759,000	4,532,000	(2,847,000)	(3,096,000)	(2,998,000)	(2,977,000)	(2,660,000)	(2,227,000)	2,000
20	Total Purchase Cost	(5,217,280)	9,660,262	9,023,905	15,225,445	12,906,865	14,253,232	(9,629,884)	(11,151,120)	(11,465,306)	(11,466,223)	(10,468,294)	(8,391,804)	(6,720,202)
21	Total Choice Bank Cost	770,354	(570,389)	(1,760,340)	(2,651,983)	(2,101,262)	(1,098,164)	298,307	1,144,057	1,465,311	1,527,595	1,550,541	1,416,139	(9,834)
22	Total Inject/With. Cost	53,638	97,365	90,257	158,453	132,939	147,766	90,085	109,079	109,079	109,079	98,690	82,906	1,279,336
23	Total Transp. Charge	29,124	54,463	50,134	88,067	73,898	82,287	49,287	59,982	59,982	59,982	54,179	45,362	706,747
24	Total Storage Cost	(4,364,165)	9,241,701	7,403,956	12,819,982	11,012,440	13,385,122	(9,192,205)	(9,838,002)	(9,830,934)	(9,769,567)	(8,764,884)	(6,847,397)	(4,743,953)

COLUMBIA STATEMENT NO. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2025-3053663
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF

NICOLE PALONEY

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2025

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 Columbia's 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, R-2022-3031211 R-2024-3046519 and R-2025-3053499. 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, R-2023-3038630 and R-2024-3047014. 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, 9680, and 9754.

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 1, which sets forth the proposed tariff filed in this proceeding. I am also responsible for Exhibit 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 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 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. 398, which contains the rate changes identified by Columbia witness Jessica 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 446,000 customers pursuant to certificates of public convenience 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, testifies regarding the Company's gas supply plan, which includes information in support of the Company's least cost procurement strategy as contained in Exhibit 5. Ms. Monnig also testifies regarding the Company's involvement in relevant Federal Energy Regulatory Commission proceedings in support of Exhibit 3. Further, Ms. Monnig is supporting Exhibit 2, Exhibit 4, Exhibit 10, and Exhibits 12 through 15.

In Columbia Statement No. 2, Jessica Fischer, Lead Regulatory Analyst with NCSC, testifies regarding Exhibits 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, supports Exhibits 1-D-1 through 1-D-3, Exhibit 6, and Exhibits 8-A through 8-E. Mr. Pluard also discusses 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 the Company's 2023 PGC proceeding (Docket No. R-2023-3038630).

Q. Please explain Exhibit 1.

A. Exhibit 1 sets forth that the proposed tariff filed in this proceeding for recovery of purchased gas costs beginning October 1, 2025, 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 7, would you please describe that exhibit?

A. Exhibit 7 was included in the pre-filing data submitted by Columbia in this proceeding on February 28, 2025. 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 7, Columbia does not presently transport gas for other utilities or interstate pipelines.

Q. Please describe Exhibit 9.

A. Exhibit 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 9, Schedule 1 shows the throughput for CHOICE[SM] customers by rate schedule by month for the period February 1, 2024, through January 31, 2025. Exhibit 9, Schedule 2 shows throughput for General Distribution Service, which represents commercial and industrial customers purchasing their gas supply from marketers by month and by rate schedule for the same period.

Q. Please explain Exhibit 11.

A. Exhibit 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 the filing. As noted in Exhibit 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 No. 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 provides that if the balance of the Hardship Fund exceeds $750,000, then the residential portion of pipeline penalty credits and refunds received will flow through the PGC until the balance falls below $750,000. From

February 27, 2023, through March 14, 2024, the Company's Hardship Fund balance was fully funded. 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. As of March 14, 2024, the Company's Hardship Fund balance fell below the $750,000 cap. Therefore, after that date, 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. See Table 1 below for 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.

Table 1

Pipeline Penalty Credits and Refunds Received

Columbia Gas of Pennsylvania, Inc.

Docket	Date Received	Amount		
October 1, 2024 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		
Equitrans: Penalty Credit Docket No. RP24-325	February 2024	47		
		514,985		

Docket	Date Received	Amount	Hardship Fund	Non-Residential
October 1, 2024 PGC Filing				
Texas Eastern Transmission: Penalty Credit Docket No. RP21-916-000	July 2024	4,743	3,435	1,308
Columbia Gas Transmission, LLC: Penalty Credit RP22-449-000	July 2024	1,707	1,236	471
		6,450	4,671	1,779

Docket	Date Received	Amount	Hardship Fund	Non-Residential
Future PGC Filing				
Columbia Gas Transmission, LLC: Penalty Credit Docet No. RP25-00278	January 2025	18,406	13,329	5,077
Texas Eastern Transmission: Penalty Credit	January 2025	46	33	13
		18,452	13,362	5,090

The penalty credits and supplier refunds in the October 1, 2024 PGC filing, totaling $514,985, is being flowed through to residential and non-residential customers for the period of October 2024 through September 2025. The non-residential portion flowed through to customers in the October 1, 2024 PGC filing totaled $1,779. The refund period for that amount is October 2024 through September 2025. The Company received two penalty credits in the amounts of $18,406 and $46 in January 2025. The residential portion will be allocated ot the Hardship Fund and the non-residential portion will be flowed through to customers in a future PGC Filing.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

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, 2025 EFFECTIVE: October 1, 2025

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” increased. The “Gas Cost Adjustment” increased. The “Pass-through Charge” increased. The “Total Effective Rate” for RSS and RDS increased.
17	Rate Summary	The “Gas Supply Charge” increased. The “Gas Cost Adjustment” increased. The “Pass-through Charge” increased. The “Total Effective Rate” for SGSS, SCD and SGDS increased.
18	Rate Summary	The “Gas Supply Charge” increased. The “Gas Cost Adjustment” increased. The “Pass-through Charge” increased. The “Total Effective Rate” increased for LGSS.
19	Rate Summary	The “Gas Supply Charge” increased. The “Gas Cost Adjustment” increased. The “Pass-through Charge” increased. The “Total Effective Rate” increased for MLSS.
20	Rate Summary	The “Penalty Credit/Pipeline Refund Passback – Non-Residential” increased. The “Residential Price-to-Compare” and “Commercial Price-to-Compare” increased. The “Rate SS – Standby Service” increased.
21	Rider Summary	The “Merchant Function Charge – Rider MFC” increased.
21a	Gas Supply Charge Summary	The “PGCC” increased. The “Rider MFC” increased. The “Total Gas Supply Charge” increased.

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

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

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	$	17.25				0.00	0.05	-	17.30
Usage Charge	$	1.04450	0.35484	0.03053	0.54213	0.00000	0.00313	0.00621	1.98134
Rate RDS - Residential Distribution Service									
Customer Charge	$	17.25				0.00	0.05	-	17.30
Usage Charge:									
Customers Electing CHOICE	$	1.04450	-	-	0.47868	0.00000	0.00313	0.00621	1.53252

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.

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	$	33.00				0.00	0.10	33.10	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	63.00				0.00	0.19	63.19	
Usage Charge									
Annual Throughput <= 6,440 thm	$	0.80554	0.35061	0.03053	0.40615	0.00000	0.00242	1.59525	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.68522	0.35061	0.03053	0.40615	0.00000	0.00206	1.47457	
Rate SCD - Small Commercial Distribution									
Customer Charge:									
Annual Throughput <= 6,440 thm	$	33.00				0.00	0.10	33.10	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	63.00				0.00	0.19	63.19	
Usage Charge: Customers Electing CHOICE									
Annual Throughput <=6,440 thm	$	0.80554	-	-	0.34270	0.00000	0.00242	1.15066	
Annual Throughput >6,440 and <=64,400 thm	$	0.68522	-	-	0.34270	0.00000	0.00206	1.02998	
Rate SGDS - Small General Distribution Service									
Customer Charge:									
Annual Throughput <= 6,440 thm	$	33.00				0.00	0.10	33.10	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	63.00				0.00	0.19	63.19	
Usage Charge - Priority One									
Annual Throughput <= 6,440 thm	$	0.79622	-	-	0.40615	0.00000	0.00239	1.20476	5/
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.67592	-	-	0.40615	0.00000	0.00203	1.08410	5/
Usage Charge - Non-Priority One									
Annual Throughput <= 6,440 thm	$	0.79622	-	-	0.00010	0.00000	0.00239	0.79871	5/
Annual Throughput > 6,440 and <= 64,400 thm	$	0.67592	-	-	0.00010	0.00000	0.00203	0.67805	5/

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/ Plus Rider EBS Option 1 or 2 - See Page 21.

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	$ 304.32				0.00	0.91	305.23	
Annual Throughput > 110,000 thm and <= 540,000 thm	$ 1,380.38				0.00	4.14	1,384.52	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$ 3,502.84				0.00	10.51	3,513.35	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$ 5,448.36				0.00	16.35	5,464.71	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$ 10,506.98				0.00	31.52	10,538.50	
Annual Throughput > 7,500,000 thm	$ 15,565.61				0.00	46.70	15,612.31	
Usage Charge:								
Annual Throughput > 64,400 thm and <= 110,000 thm	$ 0.52045	0.34900	0.03053	0.40605	0.00000	0.00156	1.30759	
Annual Throughput > 110,000 thm and <= 540,000 thm	$ 0.48659	0.34900	0.03053	0.40605	0.00000	0.00146	1.27363	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$ 0.27481	0.34900	0.03053	0.40605	0.00000	0.00082	1.06121	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$ 0.24375	0.34900	0.03053	0.40605	0.00000	0.00073	1.03006	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$ 0.21874	0.34900	0.03053	0.40605	0.00000	0.00066	1.00498	
Annual Throughput > 7,500,000 thm	$ 0.13017	0.34900	0.03053	0.40605	0.00000	0.00039	0.91614	
Rate SDS - Small Distribution Service								
Customer Charge:								
Annual Throughput > 64,400 thm and <= 110,000 thm	$ 304.32				0.00	0.91	305.23	
Annual Throughput > 110,000 thm and <= 540,000 thm	$ 1,380.38				0.00	4.14	1,384.52	
Usage Charge:								
Annual Throughput > 64,400 thm and <= 110,000 thm	$ 0.52045	-	-	-	0.00000	0.00156	0.52201	5/
Annual Throughput > 110,000 thm and <= 540,000 thm	$ 0.48659	-	-	-	0.00000	0.00146	0.48805	5/
Rate LDS - Large Distribution Service								
Customer Charge:								
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$ 3,502.84				0.00	10.51	3,513.35	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$ 5,448.36				0.00	16.35	5,464.71	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$ 10,506.98				0.00	31.52	10,538.50	
Annual Throughput > 7,500,000 thm	$ 15,565.61				0.00	46.70	15,612.31	
Usage Charge:								
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$ 0.27481	-	-	-	0.00000	0.00082	0.27563	5/
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$ 0.24375	-	-	-	0.00000	0.00073	0.24448	5/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$ 0.21874	-	-	-	0.00000	0.00066	0.21940	5/
Annual Throughput > 7,500,000 thm	$ 0.13017	-	-	-	0.00000	0.00039	0.13056	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.
5/ Plus Rider EBS Option 1 or 2 - See Page 21.

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				0.00	1.41	470.75	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00				0.00	3.45	1,152.45	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00				0.00	6.15	2,056.15	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00				0.00	12.29	4,108.29	
Annual Throughput > 7,500,000 thm	$	7,322.00				0.00	21.97	7,343.97	
Usage Charge:									
MLS Class I Annual Throughput > 274,000 thm	$	0.00937	0.34900	0.03053	0.40605	0.00000	0.00003	0.79498	
MLS Class II:									
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04481	0.34900	0.03053	0.40605	0.00000	0.00013	0.83052	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03876	0.34900	0.03053	0.40605	0.00000	0.00012	0.82446	
Annual Throughput > 7,500,000 thm	$	0.03355	0.34900	0.03053	0.40605	0.00000	0.00010	0.81923	
Rate MLDS - Main Line Distribution Service									
Customer Charge:									
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34				0.00	1.41	470.75	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00				0.00	3.45	1,152.45	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00				0.00	6.15	2,056.15	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00				0.00	12.29	4,108.29	
Annual Throughput > 7,500,000 thm	$	7,322.00				0.00	21.97	7,343.97	
Usage Charge:									
MLS Class I Annual Throughput > 274,000 thm	$	0.00937	-	-	-	0.00000	0.00003	0.00940	5/
MLS Class II:									
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04481	-	-	-	0.00000	0.00013	0.04494	5/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03876	-	-	-	0.00000	0.00012	0.03888	5/
Annual Throughput > 7,500,000 thm	$	0.03355	-	-	-	0.00000	0.00010	0.03365	5/

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/ Plus Rider EBS Option 1 or 2 - See Page 21.

Columbia Gas of Pennsylvania, Inc.

Other Rates Summary

Rate per thm

Description		Rate $/ thm		Applicable Rate Schedules
Penalty Credit/Pipeline Refund Passback - Residential		(0.00001)	1/	RSS/RDS/CAP
Penalty Credit/Pipeline Refund Passback - Non-Residential	$	(0.00017)	2/	SGSS/SGDS-P1/SCD/LGSS/MLSS
Price to Compare for Residential Gas Supply	$	0.44882	3/	RSS
Price to Compare for Commercial Gas Supply	$	0.44459	3/	SGSS (< = 64,400 thms)
State Tax Adjustment Surcharge Percentage		0.000%		Customer and Distribution Charges on all rates
Rate SS - Standby Service	$	2.29033		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 of ($0.00001) effective April 2025-March 2026
2/ Penalty Credit and Pipeline Refund passback rate of ($0.00017) effective April 2025-March 2026
3/ Please see Page No. 21c for rate components.

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	$ 0.13582 /thm	RSS/RDS
Distribution System Improvement Charge - Rider DSIC	0.30%	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	$ 0.01430 /thm	SGDS/SDS
Option 1 - Large Customer	$ 0.00745 /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	$ 0.00584 /thm	RSS
Merchant Function Charge - Rider MFC	$ 0.00161 /thm	SGSS
Purchased Gas Cost - Rider PGC	Pg. 21a & 21b	Rate Schedules specified on Page 21a & 21b
Energy Efficiency Rider - Rider EE	$ 0.00621 /thm	RSS/RDS
State Tax Adjustment Surcharge Percentage	0.000%	Customer and Distribution Charges on all rates

Gas Supply Charge Summary

Rate per thm

Rate Schedule		PGCC	Rider GPC	Rider MFC	Total Gas Supply Charge
Rate CAP - Customer Assistance Plan	$	0.34787	0.00113	0.00584	0.35484
Rate RSS - Residential Sales Service	$	0.34787	0.00113	0.00584	0.35484
Rate SGSS - Small General Sales Service	$	0.34787	0.00113	0.00161	0.35061
Rate LGSS - Large General Sales Service	$	0.34787	0.00113	-	0.34900
Rate MLSS - Main Line Sales Service	$	0.34787	0.00113	-	0.34900

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	$	0.39575	0.01047	-	(0.00001)	-	-	0.40621
Rate RSS - Residential Sales Service	$	0.39575	0.01047	-	(0.00001)	0.00010	0.13582	0.54213
Rate SGSS - Small General Sales Service	$	0.39575	0.01047	-	(0.00017)	0.00010	-	0.40615
Rate LGSS - Large General Sales Service	$	0.39575	0.01047	-	(0.00017)	-	-	0.40605
Rate MLSS - Main Line Sales Service	$	0.39575	0.01047	-	(0.00017)	-	-	0.40605
Rate RDS - Residential Distribution Service	$	0.39575	0.01047	(0.06345)	(0.00001)	0.00010	0.13582	0.47868
Rate SCD - Small Commercial Distribution (Choice)	$	0.39575	0.01047	(0.06345)	(0.00017)	0.00010	-	0.34270
Rate SGDS - Small General Distribution Service								
Priority One (P1)	$	0.39575	0.01047	-	(0.00017)	0.00010	-	0.40615
Non-Priority One (NP1)		-	-	-	-	0.00010	-	0.00010
Rate SDS - Small Distribution Service	$	-	-	-	-	-	-	-
Rate LDS - Large Distribution Service	$	-	-	-	-	-	-	-
Rate MLDS - Main Line Distribution Service	$	-	-	-	-	-	-	-

Columbia Gas of Pennsylvania, Inc.

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	$ 0.34787	0.03053	0.06345	0.00113	0.00584	0.44882
Commercial < = 64,400 thm/year	$ 0.34787	0.03053	0.06345	0.00113	0.00161	0.44459

Issued: April 1, 2025

Effective: October 1, 2025

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 $0.78462 per thm for recovery of purchased gas costs. This rate includes the commodity cost component (CC) of $0.34787 per thm, the commodity "E" Factor component (CE) of $0.03053 per thm, the demand cost component (DC) of $0.39575 per thm, and the demand "E" Factor component of $0.01047 per thm. (I)(D)

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 shall include $0.40622 per thm for recovery of Purchased Gas Demand Costs (PGDC). This rate includes the DC of $0.39575 per thm and the demand "E" Factor component of $0.01047 per thm. (I)(D)

RIDER PGC CHARGED TO CHOICE DISTRIBUTION SERVICE CUSTOMERS

Rates for each thm of gas distributed under Rate RDS and Rate SCD shall include $0.34277 per thm for recovery of Purchased Gas Demand Costs. This rate includes the DC of $0.39575 per thm, the Capacity Assignment Factor (CAF) of ($0.06345) per thm and the DC "E" Factor component of $0.01047 per thm. The CAF represents costs not assignable to Choice Distribution Service customers. (I)(D)

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 $0.39575 per thm plus the demand "E" Factor of $0.01047 per thm. The two factors total $0.40622 per thm. The Gas Supply Charge includes the PGCC of $0.34787 per thm. The Gas Cost Adjustment is the commodity "E" Factor of $0.03053 per thm. (I)(D)

For General Distribution Service customers served under Priority-One Rate SGDS, the Pass-through Charge includes the PGDC of $0.39575 per thm and the demand "E" Factor component of $0.01047 per thm, totaling $0.40622 per thm. (I)(D)

For Choice Distribution Service customers served under Rate RDS or Rate SCD, the Pass-through Charge includes the PGDC of $0.39575 per thm, the CAF of ($0.06345) per thm and the demand "E" Factor component of $0.01047 per thm, all of which total $0.34277 per thm. (I)(D)

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 $0.33230 per thm. Such rate shall be equal to the PGDC component of $0.39575 per thm as calculated above, less the CAF of $0.06345 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 $0.06345 per thm representing costs not assignable to CHOICE customers shall be included in the Price-to-Compare. (I)

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.

COLUMBIA STATEMENT NO. 4

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2025-3053663
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF

PATRICK J. PLUARD

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2025

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"), a subsidiary of NiSource Inc. ("NiSource").

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 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, a witness in the 2023 1307(f) proceeding at Docket No. R-2023-3038630, and a witness in the 2024 1307(f) proceeding at Docket No. R-2024-3047014.

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, Inc.'s Price Based Rates mechanism renewal request.

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

A. The purpose of my Direct 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) proceeding.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the exhibits identified in Table 1 below, which were included with Columbia's pre-filing data submitted on March 1, 2025:

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)**

Q. Do you have any revised exhibits?

A. Yes. Exhibit 1-D-1, Attachment 1 Firm Purchase agreements, submitted with Columbia's pre-filing on February 28, 2025, omitted a summer AMA with Colonial.

Q. Are you attaching the Revised Exhibit 1-D-1 to your testimony?

A. Yes, Revised Exhibit 1-D-1, including Revised Attachment 1, is attached to my testimony. Nothing else in Revised Exhibit 1-D-1 has been changed from Exhibit

1-D-1 submitted in Columbia's pre-filing, but the entire Exhibit is provided with Revised Exhibit 1-D-1 for convenience.

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 on its customers and balances this concern with its 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 on 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 2024-2025 winter, Columbia entered into eleven 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 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 2024-2025 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 Asset Management Arrangement ("AMA").

Q. What are Columbia's projected gas sales for the 12 months ending September 30, 2026, which is the application period for gas costs under § 1307(f) of the Public Utility Code?

A. As shown in Company Revised Exhibit 1-A, Schedule 1, Sheet 1, line 4, Columbia's projected sales for the 12 months ending September 30, 2026, total 384,887,844 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 Revised 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 $329 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 Federal Energy Regulatory Commission ("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 USM established by the Commission's Order in Columbia's 2009 1307(f) proceeding provided that customers 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. Pursuant to the Commission's Order in Columbia's 2013 1307(f) case (R-2013-2351073, 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. Pursuant to the Commission's Order in the Company's 2014 1307(f) case (Docket No. R-2014-2408268), 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 (Docket No. R-2015-2469665), 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 are the historical results of Columbia's USM?

A. Table 2 below provides lists the historic total off-system sales margins and capacity release revenues, as well as the Company and customer shares and percentages of Columbia's USM. Actual data is provided for prior USM program sharing mechanisms through the year ending September 30, 2023. Data for the current USM program year ending September 30, 2024, includes actual booked margins through September 2024 and estimated incremental revenue from October 2024 through September 30, 2025.

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	$4,196,618	$3,147,463	75%	$1,049,154	25%
Oct 2024 – Sept 2025 (est.)	$3,584,297	$2,688,223	75%	$896,074	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 up0n program?

A. Yes. Consistent with the approved 2023 1307(f) Settlement (Docket No. R-2023-3038630), Columbia executed the financial hedges shown in Table 3 below.

Table: 3 – Financial Hedge Summary

Days	Month	Dth/Month	Dth/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	BAML (Bank of America)
31	Jan-26	660,000	21,290	$ 4.090	$ 2,699,400	
28	Feb-26	660,000	23,571	$ 4.090	$ 2,699,400	
30	Mar-26	660,000	22,000	$ 4.090	$ 2,699,400	

Q. Can you provide an example of how the transactions will settle 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 2025 financial contract at $2.55 per dekatherm day, the market floats between now and April 2024. Upon the expiration of the April 2025 contract in March 2025, the difference between the expiration price and fixed price is exchanged between Columbia and the supplier. Assuming the April 2025 contract expires at $2.60 per dekatherm day, the supplier would pay Columbia the difference of $.05 per dekatherm day. The funds would flow through to the PGC customers creating a netting effect of locking in a $.05 per dekatherm day gain against the $2.60 per dekatherm day April purchase, fixing the April price to the customer at $2.55 per dekatherm day.

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 and options for this product. 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.

§53.64(c)(1) A complete list in schedule format of each spot and each long term source of gas supply, production, transportation, and storage used in the past 12 months, which 12-month period shall end 2 months prior to the date of the tariff filing, separately setting forth on a monthly basis the quantity and price of gas delivered, produced, transported or stored, maximum daily quantity levels, maximum annual quantity levels, a detailed description of warrantee or penalty provisions, including liquidated damages, take or pay provisions or minimum bill or take provisions of the purchases, balancing provisions and copies of Federal tariffs and contract provisions relating to the purchases—including demand and commodity components. With regard to each contemplated future source of supply, production, transportation or storage during each of the next 20 months, for each source, provide the name of the source, the maximum daily quantity, the maximum annual quantity, the minimum take levels, a detailed description of warrantee or penalty provisions, including liquidated damages, take or pay provisions or minimum bill or take provisions of the purchases, balancing provisions and contractual or tariffed terms of the purchases, copies of applicable Federal tariffs, the expiration date of each contract, the date when each contract was most recently negotiated and the details of such negotiation – such as meeting held, offers made, and changes in contractual obligation-- and whether current proceedings, negotiations or renegotiations are pending before the Federal Energy Regulatory Commission, and the like, to modify the price, quantity or another condition of purchase, and if so, the details of the proceedings, negotiations or renegotiations. Gas supply sources which individually represent less than 3% of the total system supply may be shown collectively, such as other local gas purchases.

Response:

Sources of gas supply and prices of gas used in the twelve months ended January 31, 2025 are set forth on Exhibit No. 1-D; projected volumes and prices for the next twenty (20) months, October 2025 through September 2026, and February 2025 through September 2025, are shown on Exhibit Nos. 1-B and 1-C, respectively. Copies of the individual, currently effective contracts and service agreements are available for review at the offices of local counsel, Post & Schell, 17 North Second Street, Harrisburg, Pennsylvania 17101-1601, and at the Commercial Operations Department of NiSource Corporate Services located at 290 W. Nationwide Blvd, Columbus, Ohio 43215.

CPA has contracts for firm transportation capacity with several interstate pipelines and negotiates separate gas supply agreements with Marketing Companies and Producers for volumes to be transported on each pipeline.

1. Affiliate Purchases - Interstate Gas
   See Exhibit No. 8-A.

2. Interstate Acquisition for System Supply

A comprehensive Request for Proposal (RFP) process for firm gas supply acquisition is initiated in the spring of each year and completed prior to the winter period. The RFP included a request for firm service natural gas supplies to Texas Eastern Zone M-3 delivery points at Texas Eastern M-2 zone index prices. Gas suppliers were selected based on their reliability, capability and pricing structure. RFPs were sent to natural gas suppliers for gas to be delivered into Columbia Gas Transmission, Eastern Gas Transmission and Storage, National Fuel Gas Supply Corporation, Tennessee Gas Pipeline, Texas Eastern Transmission and Equitrans Midstream Corporation.

Proposals were requested for varying term lengths, nomination flexibility, and innovative pricing options. CPA received proposals that provided various levels of nomination flexibility, term lengths from three months to twelve months, with prices based on gas market indices. In this process, CPA identifies the best proposals and then negotiates specific contract terms and conditions.

Supply reliability is a critically important element of CPA's supply portfolio contracting strategy; CPA fully expects its suppliers to deliver on a firm basis and the contracts contain conditions and consequences related to failure to perform.

Flexibility is another important attribute of CPA's contracts. CPA negotiates for a combination of seasonal, monthly, and daily gas supplies, which provides for the flexibility needed to meet customer demands under varying temperatures. CPA achieves part of this flexibility by contracting for winter only supplies.

As a result of the RFP process, effective for the contract period of April 2024 through March 2025, CPA entered into eleven new term gas supply purchase agreements. None of these term agreements are with affiliated companies. The resulting gas supply contract portfolio, along with monthly and daily firm supply purchases, results in winter firm gas supplies flowing under FTS capacity, which when added to volumes available from storage, are sufficient to serve CPA’s firm daily demand in the winter heating season.

A list of the firm gas term purchase contracts that are presently in effect during the period under review is provided in Attachment 1 to this Exhibit 1-D-1. In addition to the agreements listed in Attachment 1, CPA purchases spot gas from both the term contract suppliers and a multitude of other suppliers. These spot purchases are for gas that is received for a period between one day and one month in duration. The price is negotiated based on market conditions at the time of purchase.

3. Local Gas Supply Acquisition for System Supply

CPA purchases Pennsylvania gas delivered directly into its system under contracts with various initial terms and various renewal terms. In these agreements the gas price is tied to either an index price or a CPA posted price. In addition to these direct local gas purchases, CPA buys significant quantities of gas at supply points known as Aggregation Pools and at a supply point known as the Columbia Gas Transmission Appalachian Pool (TCO Pool). The gas delivered into Aggregation Pools represents local Appalachian production within the defined geographic area of the Aggregation Pool while gas delivered into the TCO pool originates from many physical locations that include multiple interstate pipeline interconnects with TCO as well as from Appalachian gas production. Though a portion of the gas in the TCO Pool has been produced in Pennsylvania, it is impossible for CPA to determine the amount of Pennsylvania production that CPA purchases at the TCO Pool.

COLUMBIA GAS OF PENNSYLVANIA, INC.

FIRM GAS PURCHASE AGREEMENTS - FEBRUARY 1, 2024 THROUGH JANUARY 31, 2025

SELLER	AGREE MENT DATE	EFFECTIVE DATE	INITIAL CONTRACT TERMINATION DATE	DATE TERMINATED	MONTHS AVAILABLE	QUANTITY DTH/DAY 11/2021-10/2022	QUANTITY DTH/DAY 11/2022-10/2023	DELIVERY POINT	TOTAL DEMAND CHARGE	MUST TAKE
BP ENERGY	8/15/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		4,000 Daily Call	LEIDY TRANSCO INTO EASTERN GAS	$0	N
CASTLETON COMMODITIES	8/25/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		4,305 Daily Call	LEIDY TRANSCO INTO NAT. FUEL	$0	N
CASTLETON COMMODITIES	8/25/2023	12/01/2023	02/29/2024	02/29/2024	DEC-FEB		7,600 Baseload	TENNESSEE GAS PIPELINE 200 LINE POOL (TGP 219)	$0	Y
CNX GAS CO LLC	8/8/2023	12/01/2023	02/29/2024	02/29/2024	DEC-FEB		10,000 Baseload	COLUMBIA GAS TRANSMISSION TCO POOL	$0	Y
COLONIAL ENERGY	10/3/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		23,535 Baseload + Daily Call	TETCO- VARIOUS	$0	Y
DTE ENERGY TRADING	8/21/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		255 Daily Call	EASTERN GAS - LOUDON	$0	N
DTE ENERGY TRADING	8/21/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		1,100 Daily Call	EASTERN GAS - PLEASANT GAP	$0	N
DTE ENERGY TRADING	9/6/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		5,500 Daily Call	EASTERN GAS - VARIOUS	$0	N
EQT ENERGY, LLC	8/16/2023	12/01/2023	02/29/2024	02/29/2024	DEC-FEB		8,000 Baseload	EQUITRANS - BRADEN RUN	$0	Y
VITOL INC.	9/19/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		28,000	EQUITRANS - BRADEN RUN	$294,000	N
COLONIAL ENERGY	3/11/2024	4/01/2024	10/31/2024	10/31/2024	APR-OCT		23,535 Baseload + Daily Call	TETCO- VARIOUS	$0	Y
ASCENT COMMODITIES	8/14/2024	12/01/2024	02/29/2025	02/29/2025	DEC-FEB		7,600 Baseload	TENNESSEE GAS PIPELINE 200 LINE POOL (TGP219)	$0	Y
ASCENT COMMODITIES	8/14/2024	11/1/2024	03/31/2025	03/31/2025	NOV-MAR		25,300 Daily Call	TENNESSEE GAS PIPELINE 200 LINE POOL (TGP219)	$0	N
CASTLETON COMMODITIES	8/19/2024	12/01/2024	02/29/2025	02/29/2025	NOV-MAR		4,305 Daily Call	LEIDY TRANSCO INTO N. FUEL	$0	N
COLONIAL ENERGY	7/30/2024	11/01/2024	03/31/2025	03/31/2025	NOV-MAR		23,535 Baseload + Daily Call	TETCO- VARIOUS	$0	Y
DTE ENERGY TRADING	8/5/2024	11/01/2024	03/31/2025	03/31/2025	NOV-MAR		255 Daily Call	EASTERN GAS - LOUDON	$0	N
DTE ENERGY TRADING	8/5/2024	11/01/2024	03/31/2025	03/31/2025	NOV-MAR		2,000 Daily Call	EASTERN GAS - PLEASANT GAP	$0	N
DTE ENERGY TRADING	8/5/2024	11/01/2024	03/31/2025	03/31/2025	NOV-MAR		10,000 Daily Call	EASTERN GAS - VARIOUS	$0	N
DTE ENERGY TRADING	8/5/2024	11/01/2024	03/31/2025	03/31/2025	NOV-MAR		4,000 Daily Call	TRANSCO LEIDY INTO EASTERN	$0	N
EQT ENERGY, LLC	7/30/2024	12/01/2024	02/29/2025	02/29/2025	DEC-FEB		8,000 Baseload	EQUITRANS - BRADEN RUN	$0	Y
EQT ENERGY, LLC	8/2/2024	12/01/2024	02/29/2025	02/29/2025	DEC-FEB		11,000 Baseload	COLUMBIA GAS TRANSMISSION TCO POOL	$0	Y
VITOL INC.	7/30/2024	11/01/2024	03/31/2025	03/31/2025	NOV-MAR		28,000 Daily Call	EQUITRANS - BRADEN RUN	$294,000	N