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October 2, 2023

VIA ELECTRONIC FILING
Ms. A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
430 N. Salisbury Street, Dobbs Building
Raleigh, North Carolina 27603

Re: Docket Nos. G-9, Sub 722, G-9, Sub 781, and G-9, Sub 786

Dear Ms. Dunston:

Pursuant to a Partial Settlement Agreement ("Settlement") dated September 7, 2021, by and between Piedmont and Public Staff – North Carolina Utilities Commission ("Public Staff"), Carolina Utility Customers Association, Inc. ("CUCA"), and Carolina Industrial Group for Fair Utility Rates IV ("CIGFUR") in Docket Nos. G-9, Sub 722, G-9, Sub 781 and G-9, Sub 786, Piedmont agreed to conduct studies to determine:

1. Whether the Company's current method of allocating its transmission plant assets to North Carolina and South Carolina is fair to each state's customers in light of the fact that the Company plans for future supply and capacity resources based on a combination of both North Carolina and South Carolina demand; and

2. Whether the Company's current regression analysis can be updated to determine a more accurate breakdown of system usage among the Company's customer classes and its North Carolina and South Carolina jurisdictions.

In addition, in its January 6, 2022, *Order Approving Stipulation, Granting Rate Increase, and Requiring Customer Notice* in the above-captioned dockets, the Commission also directed Piedmont to conduct a further study to determine:

3. Whether the Company's current allocation of its Liquified Natural Gas (LNG) plant assets between North Carolina and South Carolina is fair to each state's customers in light of the fact that the Company plans for future supply and capacity resources based on a combination of both North Carolina and South Carolina demand.

Pursuant to the foregoing, Piedmont and the Public Staff worked together to select an outside consulting firm – Atrium Economics – to conduct these studies. These studies are now complete and Atrium Economics' Final Report ("Final Report") is attached hereto for filing with the Commission.

Thank you for your assistance with this matter. If you have any questions regarding this filing, you may reach me at the number shown above.

Sincerely,

/s/ James H. Jeffries IV
James H. Jeffries IV

JHJ/bms

Enclosure

cc: Elizabeth Culpepper
Megan Jost
Brian Heslin
Pia Powers
Brian L. Franklin
Mason Maney

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the attached is being served this date upon all parties to these dockets electronically or by depositing a copy of the same in the United States Mail, First Class Postage Prepaid, at the addresses contained in the official service lists in these proceedings.

This, the 2nd day of October, 2023.

/s/ Brooke M. Szymanski
Brooke M. Szymanski

Piedmont Natural Gas Company, Inc.

Docket Nos.
G-9, Sub 722
G-9, Sub 781
G-9, Sub 786

REDACTED

ATRIUM ECONOMICS' FINAL REPORT

ATRIUM ECONOMICS
CENTERED ON ENERGY

Piedmont Natural Gas

Cost Allocation and Regression Review

July 20, 2023

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Appendices

1.0 Executive Summary

1.1 Summary of Report

Atrium Economics, LLC ("Atrium") was retained by Piedmont Natural Gas Company, Inc. ("Piedmont" or "Company") to conduct three studies required from a settlement reached in North Carolina Utilities Commission ("NCUC" or "Commission") Docket No. G-9, Sub 781, as discussed below in Section 2.0 - Project Background section of this proposal. These studies were performed to review the Company's current method of allocating transmission plant assets between its North Carolina and South Carolina jurisdictions. The studies will determine whether an updated regression analysis could more accurately divide system usage across these two jurisdictions and evaluate the fairness of the current allocation of the Company's Liquified Natural Gas ("LNG") plant between the jurisdictions.

During the engagement, Atrium issued data requests to Piedmont and held several information gathering sessions with Piedmont's subject matter experts with the attendance of the Public Staff – North Carolina Utilities Commission ("Public Staff"). Atrium reviewed the information provided by Piedmont through the data request responses and the informational meetings to gain a thorough understanding of the current allocation processes and practices and how they relate to system planning and operations.

A draft report was issued on June 9, 2023, and Atrium received comments on the report from Piedmont and Public Staff on June 30, 2023. The comments were reviewed by Atrium with edits made to the report and recorded, with Atrium's responses to the comments, in Appendix A-1 – Public Staff's Comments and Appendix A-2 – Piedmont's Comments.

1.2 Allocation of Transmission Facilities Across Jurisdictions

Piedmont currently allocates the costs of its respective transmission systems by directly assigning the costs of each of those transmission systems to the states in which they are physically located and operate. In Piedmont's prior base rate case, Public Staff contested this method stating that the LNG facility directly connects to the Transmission system in North Carolina, and as such, a portion of the North Carolina Transmission system should be allocated to South Carolina ratepayers. Atrium finds that the LNG facilities benefit North Carolina by reducing required Transmission Capacity investment (cost saving) and boosting capacity through pressure support in North Carolina, thus eliminating the need for reinforcing or expanding the Transmission System (cost saving). It's worth noting that South Carolina's beneficial use of LNG is entirely independent of its location within North Carolina's system. While it could be directly connected to Transco, it strategically occupies a favorable location within North Carolina, thereby avoiding additional transmission capacity costs. This advantageous placement is possible due to an available site where downstream pressure support was needed. With regard to the testimony of Public Staff comparing the allocation of the North Carolina transmission system with electric production facilities[1], the function of LNG facilities differs from that of electric production resources, and using annual usage data for allocation is not recommended. Allocating the transmission lines dedicated to the Robeson LNG facility similar to the LNG facility itself could be considered but would require reassessment if the capacity serves additional customers in the future. However, the benefits of this granularity should be balanced with the need for monitoring and adjusting the method if the use of the transmission lines changes.

1.3 Rate Class Regressions

Piedmont currently uses linear regression analysis to develop its peak day allocation factor as well as to determine its normalized billing determinants for weather sensitive rate classes. Piedmont's analysis uses 12 months of test year usage data and a mid-month convention for Heating Degree Days ("HDDs") weather data ("15-15 HDD") - - as a representation of bill cycle weather. In Piedmont's prior base rate case, Public Staff contested the predictive value of the Company's regression and preferred actual usage data as a representation of design conditions.

Natural gas distribution systems are engineered and constructed to provide service under design day conditions. It is not appropriate to solely rely upon the recent experience (actual usage of a recent winter period) as a method to allocate costs that were incurred based on design day. Atrium finds that the Company's regression analysis would be improved by using multiple independent variables for the previous and current month's HDDs. Atrium also believes that a regression analysis utilizing multiple years of historical data would improve the stability of the analysis.

With regard to the proposal by Public Staff to use test year winter month only regression analysis, this analysis produced unreasonable results using the 15-15 HDD method and test year usage. When the weather is properly aligned to the usage by using the previous and current month HDDs as well as using additional years of winter data, the analysis improves and is very close to the full year regression results. Atrium does not believe that omitting two-thirds of the data improves the analysis and believes additional issues may arise from using different analyses for design day and normalized billing determinants.

1.4 Allocation of LNG Facilities Across Jurisdictions

The concerns in the previous rate case were not about the appropriateness of allocating LNG facilities across jurisdictions, but rather focused on the method of allocation. Atrium agrees with the logic of distributing LNG facilities across jurisdictions, Atrium agrees with the logic for

[1] See the Direct Testimony of Dustin Metz (Docket No. G-9, Subs 722, 781, and 786 at page 10-13).

supporting the allocation of LNG facilities across jurisdictions. For example, with regard to the Robeson facility, a singular LNG facility of the size built by Piedmont in North Carolina provides economies of scale (i.e., cost per unit of capacity and deliverability) well beyond building two separate smaller LNG facilities in North and South Carolina, notwithstanding the reduced transmission pipeline capacity cost economies afforded the eastern North Carolina service territory from the strategic location. Atrium considered allocating the LNG facilities based on the actual use of the LNG facilities during peak periods, but suggests using a Design Day Peak method, which relies on regression analysis based on heating degree days. Therefore, Atrium recommends using rate class regressions for now and suggests that if future resource planning relies on MEA design day estimates; the MEA estimates would be appropriate for the allocation of LNG facilities.

Actual usage of the LNG facility varies from year to year, making it less suitable for allocation without multiple years of data. Design Day Peak, which formed the basis for the initial investment and resource planning decisions, is expected to be more consistent across multiple years, making it a more durable allocation method. It is important to note that ancillary pressure support from the LNG facilities benefits only North Carolina customers, and any changes in its usage should be monitored for potential adjustments in the allocation. The cost efficiencies from the Robeson LNG facility and Transco pipeline savings further support the design day peak based approach for jurisdictional allocation of LNG capacity costs, considering true cost causation and long-term stability.

The fundamental approach to allocating LNG facilities aims at equitable cost sharing and minimizing resource costs through economies of scale and resource sharing. All Piedmont customers benefit from the joint resource portfolio, and the allocation methodology considers the expected design day peak capacity requirements, guiding Piedmont's resource planning and procurement processes. The risks and financial impacts associated with pipeline and LNG resources are shared between the North and South Carolina jurisdictions based on the allocation methodology underlying the gas supply portfolio.

2.0 Project Background

2.1 Regulatory History

On March 22, 2021, Piedmont filed a petition in Docket No. G-9, Sub 781, seeking a general increase in and revisions to the rates and charges for customers the Company serves. The contested issues in that case related to this report are summarized below and resulted in a settlement that required Piedmont to conduct studies to evaluate the appropriate treatment of costs and determination of allocation factors.

2.1.1 Allocation of Transmission Assets and Capacity Planning

Piedmont is a local distribution company that operates in both North Carolina and South Carolina but does not fall under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Piedmont does not own natural gas transmission lines that connect its North Carolina and South Carolina service territories. Piedmont relies on Transcontinental Gas Pipeline Company, LLC ("Transco") for interstate pipeline capacity and related services to serve Piedmont's North Carolina and South Carolina service territories.

The Company plans for future capacity and storage resources based on the aggregated weighted contribution of customers and customer demands in the respective service territories for both North Carolina and South Carolina.

Currently, each state is assigned one hundred percent of the costs of all transmission assets physically located in that state, including capital and transmission-related operations and maintenance expenses.

Public Staff raised concern in Docket No. G-9, Sub 781 suggesting that the allocation method currently used by Piedmont is unfair to North Carolina and South Carolina ratepayers because Piedmont's LNG facilities are allocated on a system demand basis. Yet, transmission facilities and ongoing transmission costs are not.

2.1.2 Regression Analysis

Piedmont's existing allocation practice has been in place for many years and has formed the basis for the calculation of rates (and allocation of costs) in both North Carolina and South Carolina.

Piedmont's current allocation methodology evaluates the test year monthly usage for each customer class and then compares that usage to the HDDs for a representative monthly period, including the last half and first half of consecutive months. A simple regression is then performed, and the base usage level and heat sensitivity factor are calculated.

The Public Staff suggested that the Company's pro-forma demand allocation methodology introduces errors in the regression analysis that calculates customer class usage based on temperature. An additional concern was expressed that "the predictive value of the Company's proposed regression, using all twelve months of annual usage, breaks down slightly when higher numbers of HDDs are used."[2]

2.1.3 Allocation of LNG Assets

Piedmont's three LNG facilities (Bentonville, Huntersville, and Robeson LNG) are connected to Piedmont's natural gas transmission pipelines in North Carolina. However, the LNG facilities provide peaking services to minimize costs to both North Carolina and South Carolina service territories in combination with the Transco interstate pipeline capacity. In addition to providing peaking services to both service territories, the LNG facilities also support ancillary services (i.e., pressure support).

Because the LNG facilities are built, in part, to meet the combined North Carolina and South Carolina peak demands, the associated capital and ongoing maintenance costs are allocated based on a jurisdictional demand factor. The Pro Forma Design Day is based on a 1985 winter event - the coldest temperature experienced on Piedmont's combined North Carolina and South Carolina systems.

Public Staff raised a concern regarding the Pro Forma Design Day determination and proposed a methodology based on recent peak usage data that is assumed to be more reflective of how actual system users utilize the current plant in service.

2.2 Requested Studies/Settlement

Pursuant to a Partial Settlement Agreement ("Settlement") reached in Docket No. G-9, Sub 781 by and between Piedmont and Public Staff, Carolina Utility Customers Association, Inc. ("CUCA"), and Carolina Industrial Group for Fair Utility Rates IV ("CIGFUR") (collectively the "Stipulating Parties"), Piedmont agreed to conduct the following studies:

1. Whether the Company's current method of allocating its transmission plant assets to North Carolina and South Carolina is fair to each state's customers in light of the fact that the Company plans for future supply and capacity resources based on a combination of both North Carolina and South Carolina demand; and
2. Whether the Company's current regression analysis can be updated to determine a more accurate breakdown of system usage among the Company's customer classes and its North Carolina and South Carolina jurisdictions.

[2] This last point Atrium just evaluated in a WNA proceeding in Pennsylvania; which indicated for UGI Utilities the increase in HDDs had a minor impact on coefficients in the weather normalization regressions.

In addition, in its Order approving the Settlement, the Commission also directed Piedmont to conduct a further study to determine the following:

3. Whether the Company's current allocation of its Liquified Natural Gas (LNG) plant assets between North Carolina and South Carolina is fair to each state's customers in light of the fact that the Company plans for future supply and capacity resources based on a combination of both North Carolina and South Carolina demand.

2.3 Atrium's Role

On June 27, 2022, Piedmont issued a Request for Proposal seeking proposals from identified consultants, mutually selected by the Stipulating Parties, to conduct these studies. Atrium submitted its proposal on July 18, 2022, and was subsequently chosen by Piedmont and Public Staff to review the methods and provide a written report on its investigation, study, analyses, and conclusions.

Atrium has undertaken the following specific activities:

2.3.1 Information Gathering

During the engagement, Atrium issued data requests to Piedmont and held the following informational gathering sessions with Piedmont's subject matter experts with the attendance of Public Staff.

1) System Overview (meeting held on 11/4/2022) – Review of system maps focusing on the location of LNG facilities, transmission mains, high-pressure distribution mains, and interstate pipeline connections.

2) LNG Facility Use (meeting held on 11/4/2022) – Description and a review of data relating to using the Company's LNG facilities and implications for displacement on interstate pipelines across South Carolina and North Carolina. History of decisions and analyses to support the LNG investments.

3) Gas Supply and System Planning (meeting held on 12/9/2022) – Overview of Piedmont's gas supply and system planning processes, including the upstream pipeline capacity and storage contracts and on-system storage assets. It included a description of the coordination and treatment of transport customers and transport relating services.

4) Supply Regressions (meeting held on 12/12/2022) – Review in detail the regressions used to forecast total system supply requirements for both North Carolina and South Carolina, including a description of the weather normalization process.

5) Rate Class Design Day Regressions (meeting held on 12/12/2022) - Review in detail the regressions used to develop peak capacity allocation for each rate class, including a description of the weather normalization process.

2.3.2 Review Current Allocation Processes and Practices

Atrium reviewed the information provided by Piedmont through the data request responses and the informational meetings to gain a thorough understanding of the current allocation processes and practices and how they relate to system planning and operations.

- Review the geographical location of the Company's system, including LNG facilities.
- Review of the cost of service studies from Piedmont's last general rate case related to the jurisdictional allocation of the interstate transmission pipeline charges and LNG plant assets and any changes in the operation of these supply-related resources since the last case.
- Review special studies and jurisdictional allocation methodologies pertinent to the allocation of transmission and LNG costs.
- Review regression analyses utilized to make inferences on system usage across customer classes in both jurisdictions.
- Review how Piedmont forecasts demand to determine future supply and capacity requirements for both jurisdictions.
- Review the Company's pipeline capacity and LNG storage planning processes.
- Review the data requirements and data availability to ascertain the appropriateness of the customer class load studies or demand forecasting methods employed by the Company (i.e., interval meter data availability, granularity, and meter sampling processes, as applicable).

2.3.3 Conduct Alternative Modeling and Sensitivity Analysis

Once Atrium understood current methods and data availability, alternative modeling and sensitivity analyses were conducted. Atrium identified two primary areas of potential alternative modeling and sensitivity analyses.

1) Alternative methods for design day regressions by rate class used to inform the system peak demand allocations between South Carolina and North Carolina.

2) Evaluate the allocation of the LNG facilities based on the actual use of the LNG facilities during winter peak periods.

3.0 Guiding Principles

3.1 Theoretical Principles of Cost Allocation

The primary purpose of a cost of service study is to allocate a utility's overall revenue requirement between jurisdictions, customer classes, or between customers within a class. The goal of cost of service studies is to allocate costs in a manner that reflects the relative costs of providing service to each class. A cost of service study is an analysis of costs that assigns to each jurisdiction or class of customers within a jurisdiction, its proportionate share of the utility's enterprise-wide total cost of service, i.e., the utility's overall total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility. In addition, the concepts of a cost of service study may be used to allocate specific components of a utility's revenue requirement, such as peaking resources serving multiple jurisdictions, to result in a jurisdictional specific total revenue requirement.

In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs relate to the incremental change in costs associated with a one-unit change in service (or output) provided by the utility. As a result of using an incremental change, capacity additions, such as pipeline or peaking resources, tend to be lumpy – meaning that they may add more capacity than required to serve the increment of load assumed in the analysis. Avoiding this issue requires that the computation of the unit cost be based on the amount of capacity added rather than on the level of load that can be served.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (a historical period), the estimated book value of costs for a forecasted test year, or some combination of historical and future costs. Where a forecast test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

The cost of service study is useful in identifying cost causation, which is a critical element of allocating costs between classes and customers within the class, and adjusting rates to reduce or eliminate cross subsidies that result in rates that are not just and reasonable. A fully unbundled cost of service study provides critical information for the design of just and reasonable rates.

3.2 Cost Causation

The most important theoretical principle underlying cost studies is the principle of "cost causation," the costs assigned or allocated to particular customers should be those that the particular customers caused the utility to incur. A properly developed cost of service study represents an attempt to analyze which customer or group of customers causes the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the utility's planning, engineering, and operations and the basic economics of the components that make up the utility's system.

3.3 Characteristics of Utilities' Costs

The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs.[3] In addition, utility costs may be fixed or variable and exhibit significant economies of scale.[4]

These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies requires an understanding of the operating characteristics of the utility system. Further, different cost studies contribute to developing economically efficient rates and the cost responsibility by customer class.

Utilities are unusual in the relationship between fixed and variable costs, as the industry has a long history of recovering fixed costs through variable charges where no cost relationship exists. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-gas commodity related utility costs are fixed in the short run and do not vary with customer load changes. These fixed costs include the cost of transmission and distribution mains, service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, distribution main costs vary with growing design day demand or a growing number of customers.

3.4 Allocation of Capacity Related Costs

A complex part of the allocation process is the allocation of demand costs. Gas utilities have used several methodologies to develop allocation factors for the demand components of costs. It is not unusual for more than one demand cost allocation approach to be used in a cost of service study. The National Association of Regulatory Utility Commissioners ("NARUC") Gas Distribution Rate Design Manual identifies three fundamental methods for allocating demand related costs: *Coincident Peak* methods, *Non-Coincident Peak* methods, and *Average and Excess*

[3] Common costs occur when the fixed costs of providing service to one or more classes or the cost of proving multiple products to the same class use the same facilities and the use by one class precludes the use by another class (e.g., transmission or distribution pipeline peak capacity). Joint costs occur when two or more products are produced simultaneously by the same facilities in fixed proportions.
[4] Scale economies result in declining average cost as output increases and marginal costs are below average costs.

Demand methods. Within each of these categories are numerous specific formulations of the methods.

The concept of *Coincident Peak* (CP) demand allocation is premised on the notion that investment in capacity is determined by the utility's peak load(s). Under this methodology, demand related costs are allocated to each customer class in proportion to the demand coincident with the system peak of that customer class. The Peak Demand allocation process might focus on a single system peak, such as the highest daily demand during the test period. Alternatively, it might include the average of several cold days, either consecutive or occurring over several years, or it could be the expected contribution to the system peak under weather conditions for which the system was designed to serve, commonly referred to as a "design day."

The *Average and Excess* (A&E) demand allocation methodology, also called the "used and unused capacity" method, allocates demand related costs to the classes of service based on system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the average load is allocated based on each class's average demand. It is derived by multiplying the total demand related costs by the utility's system load factor. The remaining demand related costs are allocated to the classes based on each class's excess or unused demand, i.e., total class non-coincident demand minus average demand. The A&E method uses a weighted average of class average demands (weight = system load factor) and the "excess" demand (weight = one minus the system load factor). When the A&E method is combined with the system CP, it has the mathematical result of double counting the class average demands. This is the primary reason the A&E method is rarely used in gas embedded cost of service studies.

A simplified version of this methodology is the *Peak and Average* (P&A) methodology. This cost methodology often gives equivalent weight to peak demands and average demands. Piedmont uses a 50/50 weighting of the average demand and peak day demand. As is the case with the Average and Excess method, it allocates a portion of the utility's capacity costs on a commodity-related basis.

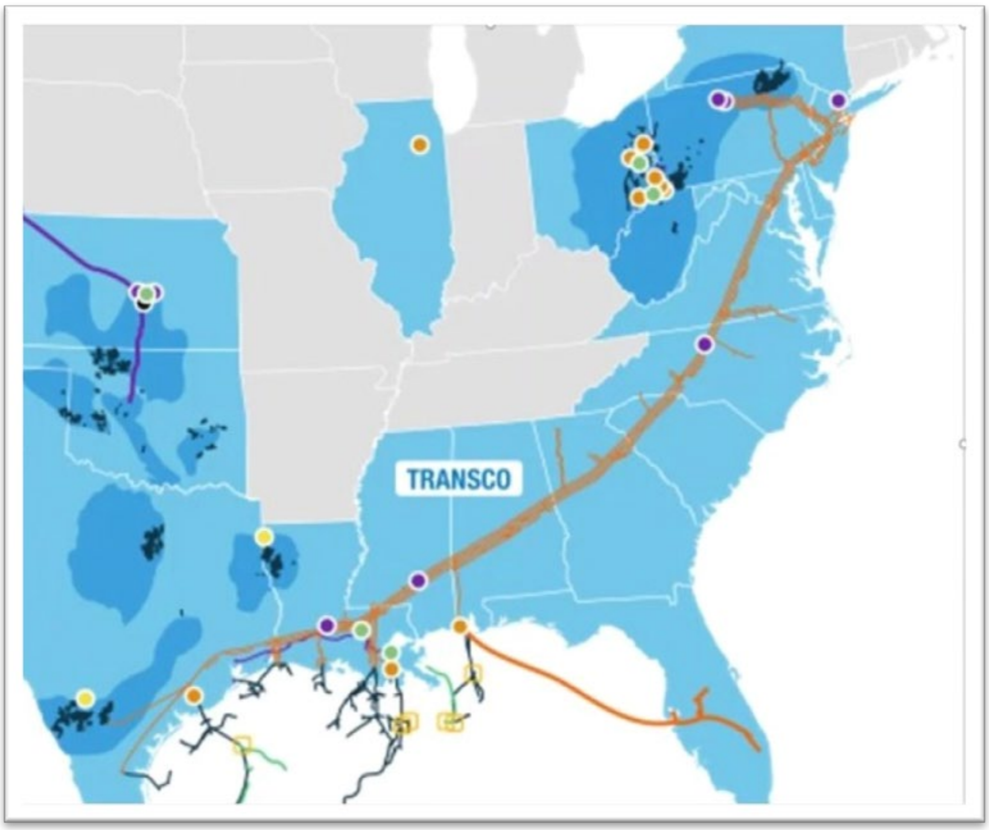
The *Non-Coincident Peak* (NCP) demand allocation methodology recognizes that certain facilities are designed to serve local peaks, which may or may not be coincident with the system peak loads. Using this methodology, demand costs are allocated based on each rate class's maximum demand, irrespective of the time of the system peak. The NCP allocation method is rarely used for gas distribution utilities. The method is more commonplace in electric cost of service studies where NCPs have some relevance to cost causation.

4.0 Gas Supply and System Planning

4.1 Summary of Upstream Pipeline Capacity

Williams Transco Pipeline Historical Background

The Transco interstate transmission pipeline system serving Piedmont's North and South Carolina service territories consists of multiple pipelines. The 10,000-mile interstate pipeline originates in south Texas and extends east and north along the eastern slope of the Appalachian Mountains to New York City, traditionally moving natural gas from the Gulf Coast to northeast markets, with North Carolina approximately in the middle of that pathway.



A lawsuit before the Federal Energy Regulatory Commission (FERC), brought by Local Distribution Companies (LDCs), challenged the interstate gas market to allow gas exchange transactions between LDCs along the interstate pipeline system. An example using the Transco Pipeline, the exchange might consist of gas delivered to Piedmont in North Carolina that was otherwise destined for an LDC at a northern Transco delivery point (e.g., New Jersey) and replacing it with an equivalent volume of shale gas available in Pennsylvania that could be routed to New Jersey. Despite opposition by interstate pipelines, FERC ruled that type of gas nomination, termed a "backhaul," would be considered a firm nomination on the interstate pipeline system.

Consistent with the FERC ruling, Piedmont maintained contracts with gas suppliers facilitated by a backhaul nomination at a lower price than buying a traditional "forward-haul," buying gas in Texas and shipping it on Transco to North Carolina. Like many LDCs in the mid-Atlantic and Northeast, Piedmont has used that type of nomination regularly because of its cost advantage for customers.

Within the last decade, influenced by the proliferation of shale gas, Transco began reversing the pipeline flow to allow both scheduling firm gas from Northern Pennsylvania down to the Gulf Coast or the traditional flow from Brownsville, Texas, to the New York Harbor, much of which is done by displacement. In effect, the pipeline became bi-directional. Because Transco was allowed to sell capacity in both directions, this provided Transco the opportunity, through the order of priorities in its tariff provisions, to declare backhauls no longer a firm type of nomination.

Piedmont had been using the backhaul nomination in its portfolio as a firm nomination because FERC had given it the same priority. Because backhauls were no longer a firm nomination provided by Transco, backhauls could be cut from daily nominations – especially on peak demand days. This created a firm capacity shortfall of approximately 200,000 dekatherms per day for Piedmont because of the loss of a firm backhaul. Therefore, Piedmont determined that backhauls on Transco were no longer the right solution for its firm customers. Piedmont then looked for an alternative solution to replace that portfolio shortfall from the change in Piedmont's contractual relationship with Transco. Piedmont determined that solution to be the development of incremental LNG peaking capacity within its North and South Carolina service territory footprint.

4.1.1 Piedmont Gas Supply Organization

The Piedmont Gas Supply organization comprises Pipeline Services, Gas Trading, and Gas Scheduling and Citygate Operations.

Pipeline Services forecasts the design day, monthly demand, and daily system demand. This group also contracts for long-term transportation and storage capacity on the upstream interstate and intrastate pipelines. Pipeline Services intervenes in interstate and interstate pipeline regulatory proceedings that may impact the upstream transportation and storage costs paid by Piedmont's customers. This group constantly monitors the issues in various docketed proceedings at FERC, intervening where applicable.

Gas Trading balances the pipeline system the same day, also called "intra-day," and then the day ahead, also called "next day." The Gas Trading team will dispatch Piedmont's gas supply contracts daily and monthly. Some of the contracts are monthly, while most are daily based, whereby Piedmont has the right to call on gas daily if needed to supplement storage or in lieu of storage if prices are favorable. The Gas Trading team administers the gas supply hedging plans, contracting for all gas supplies, releasing capacity where applicable, depending on the time of year, and negotiating and operating under asset management agreements.

Asset management agreements cover upstream pipeline assets, storage assets, and/or supply. Gas supply may be associated with the management agreement, but it's primarily the packaging of a certain amount of upstream assets, and releasing those assets to the asset manager. The asset manager will make deliveries to Piedmont's VAD or the various delivery points when Gas Trading calls for it. When the underlying gas supply or pipeline capacity is not needed for Piedmont's sales customers, the asset manager can optimize those resources in the market.

The asset manager pays Piedmont a monthly asset management fee allocated to the North Carolina and South Carolina jurisdictions.

City-gate Operations is the face of Piedmont for the brokers who nominate gas supplies on behalf of their customers to the city-gate delivery points. City-gate Operations also track imbalances on the transmission system.

4.1.2 Demand Forecasts

Piedmont's Pipeline Services group forecasts customer demand or contracts for forecasting demand in three ways. One forecast is Design Day, another is customer demand for a particular month, and the third is daily.

The Design Day forecast is the maximum daily demand using Piedmont's coldest weather scenarios, typically falling in December through February. For the monthly forecast, the maximum customer usage for a particular month is compiled, the average usage for that month of flow, and the minimum monthly usage. These three forecast scenarios determine how much capacity is available for release or off-system sales, versus how much capacity is to be held to serve customers during the particular month of flow.

This same method is used daily, as Gas Trading prepares for intra-day and next-day scheduling or weekends and holidays. The daily forecasted demand is used to inform how much open capacity is available to serve customers and any surplus capacity to be optimized for the benefit of customers.

For the prior winter (2021-2022), and prior winters, Piedmont had an internal design day forecast based on a linear regression. Piedmont is evaluating a design day forecast for the winter 2022-2023 and upcoming winters conducted by Marquette Energy Analytics (MEA).

4.1.3 Upstream Capacity and Supply Planning

Piedmont prepared a Design Day Demand and Supply Schedule Winter 2022-2023, filed annually in the Company's prudence cases in North and South Carolina.

a) Forecasted Design Day Demand

Piedmont forecasts the upcoming winter period based on the latest demand forecast and several subsequent winter periods, based on some general assumptions around forecasted growth, based on analytics from Marquette and the Company's sales-forecasted customer growth. Mid-year additions from customers electing to migrate to firm sales or firm transportation are incorporated. A portion of the special contracts load is also a firm sales component.

Piedmont also includes a 5% reserve margin to account for force majeure, interruptions, colder-than-normal weather, and circumstances outside the normal probability of outcomes from a statistical point of view. With the 5% reserve margin, the total demand for the Design Day is determined.

b) Forecasted Capacity and Supply

Piedmont's forecasted firm sales demand is approximately 1.44 BCF on a Design Day scenario for the 2022-2023 winter. From there, utilization of the upstream transportation and storage assets are modeled that provide supply to meet the forecasted demand.

The contribution of Piedmont's individual interstate pipeline firm transportation and storage contracts to serve the forecasted demand is modeled based on the type of contract and the number of days available, e.g., annual, seasonal, or winter-only (55 to 151 days).

Finally, Piedmont includes peaking resources, its LNG facilities (Robeson, Bentonville, and Huntersville), and contracted LNG from Transco, which are 5-10 day resources.

From the compilation of total capacity resources, a net position on a Design Day basis is determined. Approaching the winter of 2022-2023, Piedmont had approximately 150,000 dekatherms a day of surplus capacity, referred to as length. Based on Piedmont's anticipated system demand growth, that length is forecasted to decrease. This annually updated forecast will guide Piedmont's capacity planning, ensuring the continued evaluation of upstream capacity and associated delivered supply opportunities to reliably serve its customers' design day capacity requirements in the Carolinas.

c) Long-term Planning Considerations

Long-term supply and capacity planning involves consideration of several different factors. Generally, when excess capacity becomes shorter over time, the situation must be addressed at a certain point.

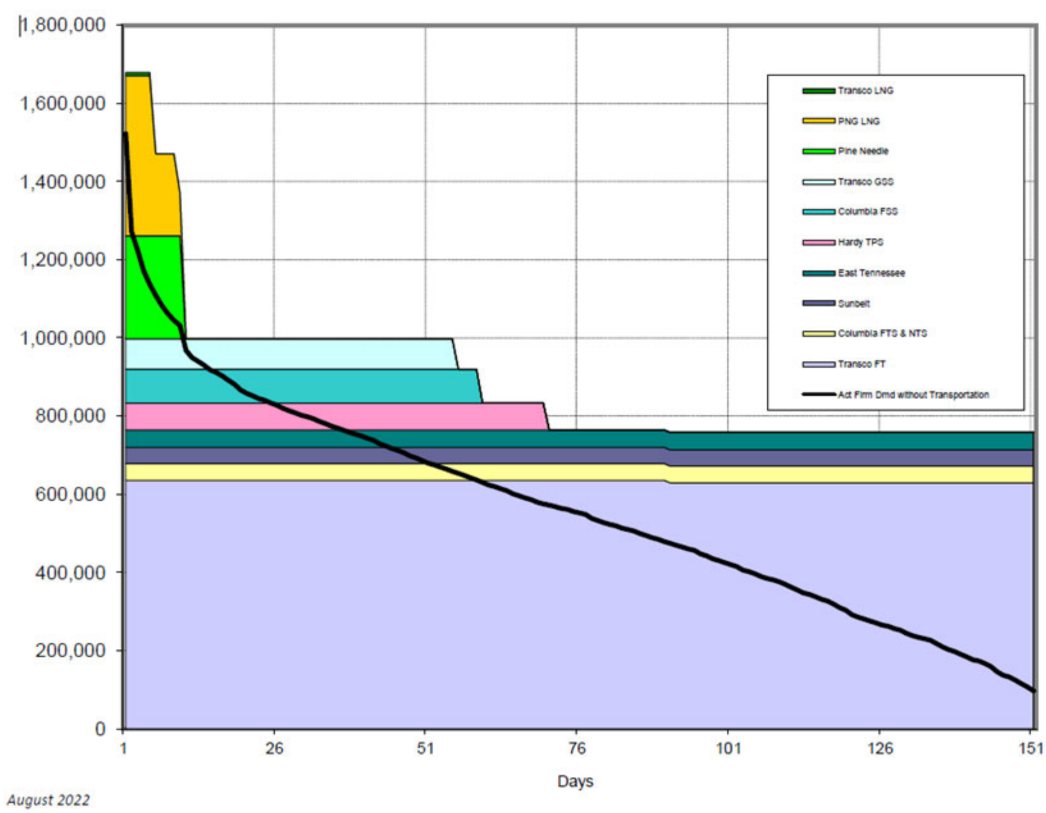
When considering the potential for an interstate upstream pipeline expansion process in the Carolinas, with a fully subscribed Transco pipeline as the main interstate pipeline resource, there may be times when capacity may be available. However, a pipeline expansion would be necessary during peak winter periods when firm capacity is needed, with delivery points to Piedmont delivery points, and the pipeline is fully subscribed.

Depending on the size, design, construction characteristics, and projected environmental impact, the pipeline expansion process can take four to five years under FERC's process. It starts when the contract is executed, and the FERC filing is prepared, through the regulatory approval process. Construction process could be one to two years, depending on the scope of the project; thus, dictating a prior four-to-five-year decision to proceed.

d) Forecasted Load Duration Curve

Piedmont's Load Duration Curve depicts supply planning for an entire winter period. It is part of Piedmont's annual prudence review that addresses the design winter. Piedmont determines whether it has the resources to meet the overall winter demand forecast by creating a load duration curve, as shown in Figure 1, below.

Figure 1 – Carolinas Forecasted Load Duration Curve – Winter 2022-2023



As typical in the industry, Piedmont evaluates design winter conditions that would be reasonably expected to occur over an entire winter. For example, the occurrence of an extreme peak day, where the rest of the winter could be relatively mild. This scenario analysis is an historical view of the experience of several winters, to determine what a design winter would look like. The analysis takes all the historical daily load data points and sorts them from highest to lowest, resulting in the load duration curve for the Piedmont system, the black line in Figure 1 (from the top left down to the bottom right).

As one might expect, there's just a few days where you might anticipate extremely cold weather, and then from there it declines. When the resources are stacked – firm transportation and storage, at the top are the green and orange blocks representing Piedmont's short duration LNG facilities. When comparing the top of the orange block, representing total capacity, to the endpoint of the black line at the upper left on the chart, the anticipated demand, the delta is roughly 150,000 Dth/day, showing some excess capacity going into winter 2022-2023.

When looking to add capacity resources, it's unlikely that it will match exactly with the expected load, due to the lumpiness of adding capacity resource investments. Piedmont can optimize those resource investments through asset management agreements, capacity releases, and other market opportunities to offset the costs of the resource investments in the interim until demand growth fills the gap, to the benefit of its customers and Piedmont.

e) Pipeline Services Annual Review

From a contracting perspective, Piedmont is periodically faced with two different decisions: whether to continue exiting contracts when up for renewal and/or pursue new pipeline or storage capacity resources.

Piedmont's pipeline system is constructed to receive gas at certain delivery points. When a contract is up for review, in anticipation of a pending notice period, system planning must consider how the downstream transmission system will be impacted absent the contract under review, and the associated supply at the specified delivery point. Drivers of whether to renew a contract include the load profile downstream of the delivery point, the expectation to receive supply at the specified delivery point, and any alternatives associated with the contract capacity, the reservation charges for the pipeline and/or storage resources, and the upstream gas commodity basis differential historically and the forward price curve. While Transco and Columbia are currently interconnected with Piedmont, alternatives are evaluated on a delivered cost basis (which includes the cost of gas at the receipt point).

Available alternatives are similarly evaluated for a new pipeline, or incremental pipeline and storage capacity. The cost of gas and the delivered supply are projected over several years, based on the forward supply price curve, against the forecasted load profile, to determine the best alternative to the need.

5.0 Allocation of Transmission Facilities Across Jurisdictions

5.1 Summary of Piedmont's Transmission Systems

This section summarizes Piedmont's transmission system with a more detailed overview in Confidential Overview of Piedmont's North Carolina and South Carolina System.

Piedmont Natural Gas operates a natural gas transmission system within North Carolina and another within South Carolina. Their transmission infrastructure consists of pipelines spanning multiple cities and counties in both states. Their North Carolina system serves over a million customers in North Carolina, including urban centers like Charlotte, Greensboro, and Winston-Salem. Their South Carolina system serves approximately 160,000 customers across various communities, including the greater Greenville area. Overall, Piedmont Natural Gas' transmission system forms the backbone of their operations in both North Carolina and South Carolina. Through its extensive network of pipelines, the Company delivers natural gas to customers.

Piedmont Natural Gas receives gas from the Transco interstate pipeline in both South Carolina and North Carolina through interconnections and delivery points along the pipeline system. The Transco pipeline, operated by Williams, is a major interstate pipeline that transports natural gas across several states, including North Carolina and South Carolina. Piedmont Natural Gas has established interconnections with the Transco pipeline at various points along Transco's route. These interconnections allow Piedmont Natural Gas to receive natural gas directly from the Transco pipeline and incorporate it into their transmission systems operating in North Carolina and South Carolina.

Piedmont does not have its transmission pipelines extending from North Carolina into South Carolina, as the Company has not found it economically feasible to extend a high-pressure transmission pipeline into the South Carolina service territory (or vice versa). Its service territory in South Carolina is uniquely situated near the Transco interstate pipeline and not contiguous to Piedmont's North Carolina service territory. A complicating factor is that crossing the state line between North and South Carolina could potentially subject the pipeline operation to FERC regulation as interstate commerce. An additional complicating risk factor is the difficulty in recent years to obtain right-of-way and the potential for intense federal, state and/or local opposition to new pipeline construction, as evidenced by the cancelation of several interstate pipeline construction initiatives up and down the mid-Atlantic and New England regions.

5.2 Current Method of Allocating Transmission Plant

In NC Docket No. G-9, Sub 781 and in its prior general rate cases, Piedmont did not allocate any transmission plant across jurisdictions. Piedmont currently allocates the costs of its respective transmission systems by directly assigning the costs of each of those transmission systems to the states in which they are physically located and operate (i.e., all of the transmission facilities located in North Carolina remained in the North Carolina jurisdictional revenue requirement and none were allocated to South Carolina).

5.3 Concerns Raised in Prior Rate Case

In NC Docket No. G-9, Sub 781, the debate between Public Staff and Piedmont revolves around the appropriateness of allocating a portion of North Carolina transmission assets to South Carolina ratepayers. Public Staff witness Dustin R. Metz's Direct Testimony suggested that the allocation method currently used by Piedmont is unfair to North Carolina and South Carolina ratepayers.

> "Piedmont's LNG facilities are allocated on a system demand basis, yet transmission facilities and ongoing transmission costs are not. The LNG facilities provide peaking and ancillary services (i.e. pressure regulation) which necessitate connection to the transmission system and which minimize costs to both North Carolina and South Carolina ratepayers. Therefore, it is apparent that the transmission system is an integral extension of the LNG facilities."[5]

Public Staff witness Metz suggested that the transmission system is an integral extension of the LNG facilities and should be considered in the allocation.

In response, Company witness Adam Long stated the LNG plants were built to support the transmission system, not vice versa. He argued that the transmission assets are operated independently from the LNG plants and are designed to meet customers' needs on a design day, regardless of the gas source. He further stated the transmission system in North Carolina is designed to serve the design day needs of Piedmont's firm customers in North Carolina.

The usage of the transmission system by the LNG facilities was also disputed, with Public Staff witness Metz stating that the LNG facilities utilize the transmission system throughout the entire year, and the usage of the transmission system is not isolated to a few discrete days during the winter or system peaking periods. Company witness Long contended that the LNG facilities injects gas into the transmission system only a few days a year. He also pointed out that while Piedmont plans for future capacity and storage resources to meet North Carolina and South Carolina demand on an aggregated basis, it is not true regarding on-system transmission.

[5] Direct Testimony of Dustin R. Metz, Docket No. G-9 Sub 722/781/786, at p. 16.

Piedmont plans for, designs, and constructs transmission capacity for its North Carolina and South Carolina systems separately and independently.

Mr. Long disagreed with Mr. Metz's contention that demand costs should be allocated based on analyzing historic system usage rather than design day requirements.

> "My problem with using actual historic usage as an allocator for fixed costs though is, as discussed above, the cause of incurring fixed costs is that we construct our system to meet the demand of our firm customers on the coldest day reasonably foreseeable. Accordingly, we believe the costs should be recovered on that basis (i.e. fixed) rather than on the basis of some historical usage."[6]

Mr. Long also disagreed with Mr. Metz's conclusions that Piedmont operates the North Carolina and South Carolina systems as a unified whole, that the North Carolina transmission system supports peak-day deliveries in both North Carolina and South Carolina, which justifies allocating some portion of the North Carolina transmission system to South Carolina.

> "Our North Carolina transmission system is not designed to deliver gas to customers in South Carolina and is, in fact, incapable of delivering gas outside of our North Carolina service territory … Piedmont's systems in North Carolina and South Carolina (and Tennessee) are not contiguous or connected, and are each wholly contained within the borders of their respective states."[7]

The Commission Order approving the Settlement between the Stipulating parties deemed the "study of whether Piedmont's current method of allocating its transmission plant assets to North Carolina and South Carolina is fair to each state's customers in light of the fact that the Company plans for future supply and capacity resources based on a combination of both North Carolina and South Carolina demands" is just, reasonable, and appropriate.[8]

5.4 Alternative Analysis – Allocation of Transmission Facilities Across Jurisdictions

5.4.1 Alternatives for the Allocation of Transmission Plant

Atrium evaluated the implication of allocating the costs associated with the lateral transmission lines dedicated to serving the Robeson LNG facility in the same manner as the LNG facility itself (line 456 and line 457). Atrium's Findings section below indicates the balance of the transmission system should not diverge from the current method of recovering 100% of the

[6] Rebuttal Testimony of Adam Long, Docket No. G-9 Sub 722/781/786, at p. 8.
[7] Rebuttal Testimony of Adam Long, Docket No. G-9 Sub 722/781/786, at p. 11-12
[8] State of North Carolina Utilities Commission, Order Approving Stipulation, Granting Rate Increase, and Requiring Customer Notice, Dated January 6, 2022, Docket No. G-9 Sub 722/781/786, at p. 53.

North Carolina transmission plant from North Carolina ratepayers and 100% of the South Carolina transmission plant from South Carolina ratepayers.

Piedmont indicated the two laterals from the Robeson LNG site are Lines 456 and 457. The gross utility plant amount for those transmission main facilities on Piedmont's books is approximately $31M. They are part of Piedmont's North Carolina rate base, which currently encompasses $3,026M of North Carolina transmission main assets - representing 1% of total main assets. As further detailed below, Atrium evaluated alternative methods of allocating the LNG facilities across jurisdictions, and the allocation to South Carolina ranged from 14.99% to 16.25%. Thus, the $31M associated with these laterals would result in $4.6M to $5.0M allocated to South Carolina, representing 0.15% to 0.16% of Piedmont's North Carolina transmission main assets.

5.4.2 Addressing the Concept of Annual Usage of the LNG Facilities

While transmission capacity costs are not related to throughput volumes, Atrium has evaluated LNG volumes to address the concept of the LNG facility operating throughout the year as a cited rationale for an allocation of the North Carolina Transmission Plant to South Carolina. Figure 2 below provides a summary of this analysis. Piedmont provided details on the total annual deliveries to North Carolina and South Carolina and LNG volumes relating to injection, withdrawal, and boil-off. Total throughput volumes associated with the LNG facility include LNG storage injections, withdrawals to meet demand requirements, and boil-off volumes, represent 0.57% of total deliveries across the last three years, 2020-2022. South Carolina deliveries represent approximately 12.75% of total deliveries. Multiplying 0.57% times 12.75% results in 0.07% of LNG related volumes associated with South Carolina deliveries.

Figure 2 – Annual Use of LNG Facilities

Year	NC East Deliveries	NC West Deliveries	SC Deliveries	Total NC and SC Deliveries	LNG Volumes (injection, withdrawal, boil-off)	LNG Volumes as % of Total Deliveries	SC Volumes as % of Total Deliveries	SC LNG Volumes as % of Total Deliveries
2019 (mths 7-12)	118,176,129	92,849,163	30,777,781	241,803,073	1,807,150	0.75%	12.7%	0.10%
2020	207,270,110	183,360,086	66,941,427	457,571,623	1,144,130	0.25%	14.6%	0.04%
2021	213,845,348	230,694,195	67,384,169	511,923,712	2,984,673	0.58%	13.2%	0.08%
2022	213,025,812	262,548,982	57,287,274	532,862,068	4,471,768	0.84%	10.8%	0.09%
Grand Total	**752,317,399**	**769,452,426**	**222,390,651**	**1,744,160,476**	**10,407,721**	**0.60%**	**12.75%**	**0.08%**
		3 Year Avg	**63,870,957**	**500,785,801**	**2,866,857**	**0.57%**	**12.75%**	**0.07%**

5.5 Atrium's Findings – Allocation of Transmission Facilities Across Jurisdictions

LNG benefits North Carolina by reducing required Transmission capacity investment (cost saving) and boosting capacity through pressure support in North Carolina, thus eliminating the need for reinforcing or expanding the Transmission System (cost saving). The system reinforcement role of LNG relates only to the North Carolina service area where pressure support is needed, and, at least in the case of Robeson, additional transmission line investments were avoided due to the LNG facility's location.

Moving on to South Carolina, LNG plays a pivotal role in reducing the required interstate pipeline capacity through displacement, as it also provides a stable peaking gas supply to both North and South Carolina. Importantly, the displacement occurring during system peak periods in South Carolina has no cost impact on the transmission system in North Carolina.

It's worth noting that South Carolina's beneficial use of LNG is entirely independent of its location within North Carolina's system. While an LNG facility could be directly connected to Transco, Piedmont's LNG facilities strategically occupy favorable locations within North Carolina, avoiding additional on-system transmission capacity costs. This advantageous placement is possible due to available sites where downstream pressure support was needed.

Lastly, while Virginia and North Carolina employ the A&E method for the allocation of electric production and transmission plants, it's important to note that the function of the LNG facility differs from that of an electric utility's production resources. Unlike an average demand-serving (base load) resource, the LNG facility serves a distinct purpose and operates differently. While Atrium has presented data on the annual use of LNG facilities in Figure 2 above, Atrium does not recommend using this as a basis for allocating transmission plant nor of the LNG facilities themselves.

One area of potential enhancement is to allocate the lateral transmission lines specifically built and dedicated to serve the Robeson LNG facility in the same manner as LNG facility (line 456 and line 457). However, this would need to be reevaluated if, in the future, a portion of these laterals' capacity were used to serve additional customers of Piedmont in North Carolina and is not fully dedicated to the LNG facility. It also represents a very small portion of total transmission plant, so the benefits of this granularity should be weighed with the need to monitor and change the allocation method if the use of the laterals change.

6.0 Rate Class Regressions

6.1 Current Method of Rate Class Regressions

Piedmont uses linear regression of rate class use per customer and weather to determine a design day demand by rate class for its weather sensitive rate classes. This design day demand is then used to develop a peak capacity allocation factor for cost allocation. Piedmont uses the same regression analysis for determining weather normalized billing determinants by rate class for the weather sensitive rate classes. Piedmont previously relied on the rate class regression analysis to determine class design day responsibility for cost recovery allocation.

6.2 Current methods

The current design day allocation method calculates the design day throughput for each firm service customer class based on a design day condition of 8.71 degrees Fahrenheit, or 56.29 HDDs[9]. Piedmont uses linear regression analysis of monthly use per customer and monthly HDDs to determine a Base Load Factor and Heat Sensitivity Factor for customers in each weather-sensitive customer class. The Base Load Factors, Heat Sensitivity Factors, number of customers, and design day HDDs are used to calculate the design day throughput by customer class.

Piedmont defines the Base Load Factor as the expected base usage per customer on days with zero HDDs. The Heat Sensitivity Factor is the expected additional use per customer for each increment of HDD.

Piedmont's regression analysis uses test year actual monthly throughput from billing data and HDDs. The analysis is run on 12 months of usage and HDD. Piedmont's regression analysis uses "15-15" HDDs for customer classes with cycle billing to account for the customer meter readings occurring on different days throughout the month. The "15-15" HDDs set the monthly HDDs based on the weather experienced from the 16th day of the prior month to the 15th day of the current month. This is done to better represent the HDDs experienced by the monthly cycle billing data (meter reads). For the large volume service rate classes, whereby all customer meters are read from the first of the month to the last day of the month, Piedmont uses calendar month HDDs for the regression analysis.

Piedmont determines which rate classes are weather sensitive by the significance of the results of the regression analyses.

Piedmont has incorporated forecasting support from MEA to address refinements to its methodology. Some of the input assumptions to this forecast may change. The transition from

[9] *Docket No. G-9, Sub 771*

the internal Piedmont Excel model to MEA, with a robust analytical and ensemble model approach, resulted in a step-change increase in demand, about 100,000 Dth per day on a Design Day. This increase in demand impacts upstream pipeline capacity requirements and the potential of the downstream transmission system's ability to manage the increased capacity efficiently. For this reason, Piedmont is reviewing the underlying assumptions from the new model and has indicated they are in the early stages of internally evaluating its pipeline system and the impacts of that review. Given the initial results of the transition to the MEA model, Piedmont has stated their intent not to get ahead of decisions on the new forecasting methodology by reacting to the capacity deficit in the near term.

6.3 Concerns Raised in Prior Rate Case

In NC Docket No. G-9, Sub 781, Piedmont agreed to conduct three studies following the conclusion of that rate case before the earlier of Piedmont's next general rate case or its 2023 annual review of gas costs. The issues raised in that case and the findings by the NCUC are discussed in this section.

6.3.1 Whether the Company's current regression analysis can be updated to determine a more accurate breakdown of system usage among the Company's customer classes and its North Carolina and South Carolina jurisdictions.

The origin of this issue in Public Staff witness Mr. Metz's testimony suggests that the Company's pro forma demand allocation methodology introduces errors into the regression analysis that calculates customer class usage based on temperature. Also, Witness Metz had "concerns that the predictive value of the Company's proposed regression, using all 12 months of annual usage, breaks down slightly when higher numbers of HDDs are used."[10] Excerpts from Mr. Metz's understanding of Piedmont's design day study and subsequent allocation method are summarized below.

- Uses an aggregate of 12 months of historic test year data and through linear regression analyses calculates customer class usage based on temperature.
- Evaluates the 2020 test year monthly usage for each individual customer class, and then compares that usage to cumulative hours in the same month in which the weighted average temperature was less than 65 degrees (i.e. HDDs) for the gas day. A simple regression is then performed and the base usage level (the starting point of expected usage at 65 degrees) and a heat sensitivity factor (the amount of natural gas used per customer class based on a decrease in temperature) are calculated.

[10] Direct Testimony of Dustin R. Metz, Docket No. G-9 Sub 722/781/786, at p. 26.

- Upon completion of the regression analyses, the design day temperature (“DDT”) is applied.

Mr. Metz identified components of the Company’s demand allocation methodology that appear to introduce errors into the regression analysis that relies upon a linear relationship between independent and dependent variables.

- The Company’s methodology utilizes test year usage (demand) but escalates the usage to represent a theoretical total volume demand that assumes the reoccurrence of an event that has occurred only once, in 1985. This theoretical usage is then allocated between North Carolina and South Carolina.
- The Company has proposed an allocation to North Carolina of 85.39% and to South Carolina of 14.61%, with an aggregate expected firm sales usage of 1,354,754 dekatherms (“Dths”), excluding electric generation usage.
- A key takeaway to approaches to cost allocation that rely on the use of regression analysis is that there are not enough data points to feel confident with the statistical equation. This is in part because improper data resolution (usage months) distorts projected loads and the relationship of base factor and heating coefficient are not consistent.

Based on his analysis, Mr. Metz proposed an allocation methodology based on recent peak usage data, which he contends is more reflective of how customers utilize the current system plant in service.

The Commission Order approving the Settlement between the Stipulating parties deemed just, reasonable, and appropriate the study of an “updated regression analysis to determine a more accurate breakdown of system usage among customer classes and the North Carolina and South Carolina jurisdictions before the earlier of Piedmont’s next general rate case or 2023 Annual Review.”[11]

6.4 Atrium’s Alternative Analysis – Rate Class Regressions

6.4.1 Alternatives for the rate class regression analysis

Atrium evaluated alternatives to Piedmont’s test year rate class regressions using 15-15 HDDs. Atrium believes that the 15-15 HDD method to represent the weather experienced during a billing cycle could be improved. Specifically, the 15-15 HDD method fails to align HDDs and usage for most customers’ billing cycles, and extreme weather early or late in the month is not captured with the associated usage. Additionally, based on our experience, Atrium believes that

[11] State of North Carolina Utilities Commission, Order Approving Stipulation, Granting Rate Increase, and Requiring Customer Notice, Dated January 6, 2022, Docket No. G-9 Sub 722/781/786, at p. 53.

using 12-month test year data for regression analyses is too limited and a more robust analysis would include additional years of data.

The first alternative was a rate class regression analysis using two independent variables for weather, the current and previous month's HDDs, as opposed to Piedmont's 15-15 HDD. This analysis will account for cycle billing HDDs in the regression analysis, which should be superior to splitting the HDDs mid-month. The second alternative proposed was a bill cycle HDD regression where the individual bill cycle HDDs are calculated, and the regression analysis is run for each bill cycle. However, this method is quite data intensive. Atrium's Findings section below indicates moving to a multi-year regression analysis with previous and current month HDDs strikes an appropriate balance between simplicity, ease of execution, and quality of results.

6.4.2 Addressing the Concept of Design Day using Winter Months Regressions

Based on issues raised in the prior rate case, Atrium also tested a regression analysis using only the peak winter months to determine the coefficients. The issue raised related to the test year regression results for winter months indicating a lower heat sensitivity factor than using all months of the year. Atrium reviewed this winter only analysis using the 2020 test year data and the 15-15 HDD and determined that the regression statistics were poor, and the resulting intercept and coefficients produced unreasonable results. Atrium conducted a multi-year regression analysis of the winter months using the previous and current HDDs and the regression statistics were vastly improved; however, the full data set results are still superior.

6.5 Atrium's Findings – Rate Class Regressions

Our preliminary comparison of regression alternatives was performed using the data available for the test year. The initial findings were that the previous and current month HDD regressions and the bill cycle specific regressions produced better statistical results than the 15-15 HDD method. The preliminary comparison also resulted in the previous and current month's HDD having better statistical results than the bill cycle HDD analysis. We therefore determined that the previous and current month's HDD analysis sufficiently accounted for the cycle billing and that the amount of data and analysis required to run the bill cycle HDD analysis was not necessary or practical. Our preliminary comparison further showed a closer back cast range, on a monthly basis, for the current and previous month's HDD analysis versus the others. Figure 3 shows the results of our preliminary comparison for the Residential rate class.

Figure 3 – Residential Rate Class Regressions Comparison

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	Current Method 15-15 HDD basis		Alternative 1 Previous/Current Month HDDs		Alternative 2 Billing Cycle HDDs	
Regression Statistics						
Corralation (R^2)	0 93859		0 99036		0 97418	
Standard Error	0 86848		0 36266		0 52942	
Observations	12		12		228	
F-statistic	152 84		462.41		8527 59	
p-value	2.21E-07		8.47E-10		1.89E-181	
Coefficients						
Base Factor	0 85361	dt/cust/mo	0 59620	dt/cust/mo	0.68733	dt/cust/mo
Heat Factor (current mo.)	0 01442	dt/HDD/cust	0 00490	dt/HDD/cust	0 01507	dt/HDD/cust
Heat Factor (previous mo.)	n/a		0 01068	dt/HDD/cust	n/a	
Forecast						
Normalized Annual Volume	38,727,358	dt	39,122,759	dt	38,788,259	dt
Test year volume vs. Normal	-13.0%		-13.8%		-13.1%	
Test year weather vs. Normal	-15.8%		-15.8%		-15.5%	
Design Day Forecast @ 56.29 HDD	589,311	dt	629,221	dt	610,808	dt
Load Factor	18.0%		17.0%		17.4%	

Modeled Test Year

Actual dekatherms by month		Current Method Modeled	Difference	%	Alternative 1 Modeled	Difference	%	Alternative 2 Modeled	Difference	%
January	6,545,032	5,102,453	(1,442,580)	-22.0%	6,519,806	(25,226)	-0.4%	6,312,860	(232,173)	-3.5%
February	6,444,001	6,659,332	215,331	3.3%	6,430,437	(13,564)	-0.2%	6,116,715	(327,286)	-5.1%
March	5,258,676	5,074,124	(184,552)	-3.5%	5,056,896	(201,780)	-3.8%	5,281,479	22,804	0.4%
April	2,613,438	2,567,653	(45,785)	-1.8%	3,000,875	387,437	14.8%	2,693,742	80,304	3.1%
May	1,845,550	2,319,794	474,244	25.7%	2,059,304	213,754	11.6%	2,164,004	318,454	17.3%
June	1,173,180	843,908	(329,271)	-28.1%	1,284,094	110,914	9.5%	1,072,830	(100,350)	-8.6%
July	761,432	643,498	(117,934)	-15.5%	493,092	(268,340)	-35.2%	544,153	(217,278)	-28.5%
August	641,393	591,230	(50,163)	-7.8%	412,940	(228,453)	-35.6%	476,058	(165,335)	-25.8%
September	698,433	591,673	(106,760)	-15.3%	543,744	(154,689)	-22.1%	565,178	(133,254)	-19.1%
October	1,003,533	1,263,327	259,795	25.9%	1,046,320	42,787	4.3%	1,152,376	148,843	14.8%
November	1,864,079	2,312,788	448,710	24.1%	2,215,919	351,840	18.9%	2,100,844	236,765	12.7%
December	4,856,013	5,759,762	903,749	18.6%	4,640,374	(215,639)	-4.4%	5,144,381	288,368	5.9%
TOTAL	33,704,759	33,729,542	24,783	0.1%	33,703,801	(959)	0.0%	33,624,621	(80,138)	-0.2%

	Current Method		Alternative 1		Alternative 2	
Maximum Monthly Difference - Long	903,749	December	387,437	April	318,454	May
Maximum Monthly Difference - Short	(1,442,580)	January	(268,340)	July	(327,286)	February

Atrium believes that an additional area of potential enhancement is to use multiple years of data for the regression analysis. Regressions with multiple years of data are superior for forecasting future outcomes and relationships between dependent and independent variables. Multiple years of data provide more variation, resulting in a regression that can better explain the relationships between usage and HDD. Atrium performed the previous and current HDD regression analysis using three years of data. While the resulting intercept and coefficients were close to the test year version, we recommend that Piedmont use multiple years to run future regression analyses for determining design day allocations for weather sensitive classes.

7.0 Allocation of LNG Facilities Across Jurisdictions

7.1 Summary of Piedmont's LNG Facilities

This section summarizes Piedmont's LNG facilities with a more detailed overview provided in Confidential Overview of Piedmont's North Carolina and South Carolina System.

Piedmont's three LNG facilities (Bentonville, Huntersville, and Robeson) are connected to Piedmont's natural gas transmission pipelines in North Carolina. They are utilized to provide peaking services to minimize costs to both North Carolina and South Carolina service territories in combination with the Transco interstate pipeline capacity.

7.2 Current Method of Allocating LNG Facilities

In NC Docket No. G-9, Sub 781, and in its prior general rate cases,, Piedmont allocated the LNG facilities from North Carolina to South Carolina based on the design day estimates resulting from the rate class regressions (i.e., a ratio based on North Carolina and South Carolina estimated peak design day demands).

7.3 Concerns Raised in Prior Rate Case

In NC Docket No. G-9, Sub 781, the debate between Public Staff and Piedmont revolves around the fairness of the method used to allocate LNG facilities between North Carolina and South Carolina. The origin of this issue in Public Staff witness Metz direct testimony described his concerns relating to Piedmont's current method of allocating LNG plant assets between North Carolina and South Carolina.

> *"This Pro Forma Design Day allocation is not a demand allocation based on actual test year data, but is escalated to an "expected" demand based on a 1985 winter event, which is the coldest temperature experienced to date on Piedmont's system. In other words, these test year costs are not allocated solely on the basis of historical test year system operating data, but rather, the historical data is extrapolated to a theoretical expectation that may or may not occur again at some future time. Therefore, I have concerns regarding the usage of the Pro Forma Design Day allocation proposed by the Company that I discuss later in my testimony. "*[12]

As described in this report's Rate Class Regression section, Public Staff witness Metz raised concerns about the regression used to estimate the design day allocation for each rate class that informs the jurisdictional split of the LNG facilities. As such, Public Staff witness Metz proposed an allocation methodology based on recent peak usage data, reflecting the use of the system.

In response to the testimony provided by Public Staff witness Metz, Company witness Long provided additional context on the current method.

> *"One of the incidental benefits of having LNG plants connected to the North Carolina transmission system is that it provides some flexibility in regard to scheduling deliveries off of Transco in South Carolina because gas flowing*

[12] Direct Testimony of Dustin R. Metz, Docket No. G-9 Sub 722/781/786, at p. 11.

> *toward North Carolina can be diverted to a delivery point in South Carolina. This occurs because the Company is injecting vaporized LNG into the North Carolina system (thereby reducing the need for flowing Transco gas in North Carolina). This combination of supply assets allows the utilization of the North Carolina LNG plants in conjunction with Transco delivery rights to benefit both States. This benefit is recognized by allocating a portion of the LNG plant costs to South Carolina."*[13]

Concerning the allocation method, Company witness Long stated the allocation is determined by comparing the design day obligations of both states, as the requirement for upstream capacity and peaking capacity is based upon projected design day demand in each state. Company witness Long stated, "we believe that this is the proper approach for the reasons discussed above."[14]

The Commission Order approving the Settlement between the Stipulating parties made the following finding:

> *"Given the benefits that are afforded to Piedmont's South Carolina service territory by Piedmont's LNG plants sited in North Carolina, the Commission finds it is reasonable and appropriate to require that, prior to the earlier of Piedmont's next general rate case or its 2023 Annual Review, that Piedmont study the allocation of its LNG plant assets between North Carolina and South Carolina for the purpose of determining whether its current method is fair to each state's customers in light of the fact that Piedmont plans for future supply and capacity resources based on demand created by Piedmont's North Carolina and South Carolina service territories."*[15]

7.4 Alternative Analysis – Allocation of LNG Facilities Across Jurisdictions

7.4.1 Actual Usage Alternatives for the Allocation of LNG Facilities

Atrium analyzed three alternative methods of allocating LNG facilities across North Carolina and South Carolina: (1) allocated based on the actual use of the LNG facilities during peak periods, (2) allocated based on the design day developed by MEA; and, (3) allocated using the updated recommended regressions discussed in Section 6.4.

[13] Rebuttal Testimony of Adam Long, Docket No. G-9 Sub 722/781/786, at p. 12-13.
[14] Rebuttal Testimony of Adam Long, Docket No. G-9 Sub 722/781/786, at p. 13.
[15] State of North Carolina Utilities Commission, Order Approving Stipulation, Granting Rate Increase, and Requiring Customer Notice, Dated January 6, 2022, Docket No. G-9 Sub 722/781/786, at p. 54.

Figure 4 – Actual Usage - July 2019 – 2022 (Top 10 Days Shown)

Date	Actual HDDs	Design Day HDDs	Difference in HDD	LNG Dispatched	Firm Sales Sendout North Carolina	Firm Sales Sendout South Carolina	Total Firm Sales Sendout	NC Percent	SC Percent
1/29/2021	31.2	56.29	(25.09)	152,243	634,122	107,145	741,267	85.5%	14.5%
1/3/2022	30.4	56.29	(25.89)	173,240	524,872	97,127	622,000	84.4%	15.6%
1/7/2022	34.3	56.29	(21.99)	149,036	615,490	113,024	728,513	84.5%	15.5%
1/11/2022	31.3	56.29	(24.99)	186,186	604,804	118,433	723,237	83.6%	16.4%
1/16/2022	36.2	56.29	(20.09)	188,603	703,613	144,623	848,236	83.0%	17.0%
1/17/2022	32.6	56.29	(23.69)	117,934	637,382	130,484	767,866	83.0%	17.0%
1/21/2022	38.8	56.29	(17.49)	203,239	785,939	141,544	927,483	84.7%	15.3%
1/22/2022	37.4	56.29	(18.89)	150,052	733,284	132,269	865,552	84.7%	15.3%
1/29/2022	38.8	56.29	(17.49)	170,480	754,628	144,646	899,274	83.9%	16.1%
2/14/2022	28.1	56.29	(28.19)	148,454	538,272	102,010	640,282	84.1%	15.9%
							All Days (7/19 - 11/22)		
							Max	85.9%	20.1%
							Min	79.9%	14.1%
							Average	83.5%	16.5%

Figure 4 above summarizes an analysis of peak day withdrawals across all LNG facilities from July 2019 through December 2022. The last two columns provided the percent of North Carolina and South Carolina send out for each day (with this figure only showing the top 10 days). The max for South Carolina across this period is 20.1%, with an average of 16.5%.

7.4.2 Design Day Alternatives for the Allocation of LNG Facilities

Figure 5 below summarizes the 2022-2023 design day forecast developed by MEA. The MEA results indicate South Carolina represents 16.25% of the expected design day requirements.

Figure 5 – Design Day Developed by MEA

	2022-2023 Estimate	% of Total
North Carolina East	307,058	21.25%
North Carolina West	903,072	62.50%
South Carolina	234,763	16.25%
SC and NC	1,444,893	

As described in more detail in the Rate Class Regression section, Atrium evaluated a regression method that results in more robust statistics. That regression method was performed for all weather sensitive rate classes to estimate the impact of this updated regression method on the allocation of the LNG facilities. Atrium kept the non-heat sensitive classes' design day the same as the Company's analysis in the last case to isolate the impact of changing the regression method. Rate schedule T10 migrated to Rate Schedule 103 in July 2022, so Atrium only ran regressions on 2.5 years of data for both classes. Figure 6 below summarizes the results, indicating South Carolina represents 14.99% of the expected design day requirements.

Figure 6 – Atrium's Design Day Rate Class Regressions

Jurisdiction	Rate Schedule	Docket No. G-9, Sub 781 Design Day Allocation	Percentage	Multi-Year PHDD/CHDD Design Day Allocation	Percentage
North Carolina					
	101 - Residen ial	589,311	50 9%	644,941	52.9%
	102 - Small General	296,759	25.7%	314,659	25.8%
	143/102 - Small General Motor Fuel	33	0.0%	33	0.0%
	152 - Medium General	39,305	3.4%	32,832	2.7%
	103, 113 - Firm Large General	145,206	12.6%	135,876	11.2%
	143/103, 143/113 - Firm Large General Motor Fuel	2,840	0.2%	2,840	0.2%
	T-10 - Firm Military	12,226	1.1%	12,600	1.0%
	Firm Municipals	71,199	6 2%	74,453	6.1%
Total North Carolina Dts for Design Day Allocation		**1,156,878**		**1,218,233**	
South Carolina					
	201 - Residen ial	120,153	60.7%	132,470	61.7%
	202 - Small General	56,415	28 5%	60,395	28.1%
	252 - Medium General	6,596	3.3%	6,188	2.9%
	203, 213 - Firm Large General	14,265	7.2%	15,279	7.1%
	Contract - Firm Service	446	0 2%	446	0.2%
Total South Carolina Dts for Design Day Allocation		**197,876**		**214,778**	
Grand Total Carolinas Design Day Dts for Design Day Allocation		**1,354,754**		**1,433,011**	
North Carolina Design Day Allocation %			**85.39%**		**85.01%**
South Carolina Design Day Allocation %			**14.61%**		**14.99%**

7.5 Atrium's Findings – Allocation of LNG Facilities Across Jurisdictions

The concerns raised in the prior rate case revolve around the method of allocating LNG facilities, not the appropriateness of allocating these facilities across jurisdictions. Atrium agrees with the logic for supporting the allocation of LNG facilities across jurisdictions. For example, with regard to the Robeson facility, a singular LNG facility of the size built by Piedmont in North Carolina provides economies of scale (i.e., cost per unit of capacity and deliverability) well beyond building two separate smaller LNG facilities in North and South Carolina, notwithstanding the reduced transmission pipeline capacity cost economies afforded the eastern North Carolina service territory from the strategic location of the Robeson LNG plant.

Atrium believes a Design Day Peak method is the most durable allocation method and is indicative of system planning. Below is a summary of the alternatives evaluated.

- Actual Use - Reviewing past use of the LNG facility resulted in ~16.5% allocation to South Carolina.
- Design Day MEA - Reviewing past use of the LNG facility resulted in ~16.5% allocation to South Carolina.
- Design Day Atrium Regressions – Multi-year regressions using previous and current months' HDDs resulted in ~15% allocation to South Carolina.

As noted above Piedmont is in the process of evaluating the MEA design day methods and as such, at this time, Atrium recommends relying on the recommended rate class regressions. If in the future Piedmont relies on the MEA design day estimates across jurisdiction for resource planning those would be appropriate for use in the allocation of the LNG facilities.

The challenge with actual usage is that actual usage can vary from year-to-year and would be best applied by relying on multiple years of data. Design Day Peak was the basis for the initial LNG investment and ongoing decisions relating to supply resources, which are acquired to serve both jurisdictions. It is reasonable to expect Design Day to vary significantly less across multiple years and result in a more durable allocation method. This allocation method is consistent with the allocation used for allocating upstream transmission pipeline capacity.

It is also worth noting that any ancillary pressure support provided by the LNG facilities only benefits customers in North Carolina. Inherently, allocating LNG facility costs across jurisdictions using either design day or actual peak day usage does not consider this additional ancillary service. Piedmont indicated that the newly added Robeson facility has not been specifically dispatched for pressure support outside of provided peak day supply. This may change over time and should be monitored to ascertain if an additional portion of the LNG facilities should be allocated to North Carolina for this localized benefit.

The cost efficiencies provided by the LNG facilities in North Carolina allowed Piedmont to redirect a portion of Transco firm pipeline capacity, and peaking supply provided by the LNG facilities, to South Carolina by displacement, thereby avoiding the cost of firming up, at forward haul rates, Transco pipeline capacity formerly firm under FERC back haul provisions.

Aside from the economies of scale inherent in the LNG facilities and Transco pipeline cost savings from avoided firm transportation rates, the true cost causation approach to cost allocation dictates the jurisdictional allocation of the LNG capacity cost on a design day peak basis. While Atrium's analysis of the alternative allocation methods demonstrates relatively small differences in the resulting proportional allocation of LNG facilities between the North and South Carolina jurisdictions, the approach that best reflects the true cost causative nature of this peak capacity resource and the most durable (i.e., long-term stability) allocation method is the design day peak based approach.

Finally, the fundamental approach to allocating the LNG facilities is grounded in the equitable cost sharing through minimizing resource costs through economies of scale and sharing of resources. All Piedmont customers benefit through this joint resource portfolio. The joint portfolio costs are based on the expected design day peak capacity requirements, the principal guiding criteria for Piedmont's resource planning and procurement processes. The Transco pipeline contracts are not unique to the two state jurisdictions; they are Piedmont contracts, not Piedmont North Carolina-only or South Carolina-only contracts. Likewise, the inherent risks of performance of these pipeline and LNG resources and the associated financial impacts are also shared between the two jurisdictions according to the allocation methodology underlying the gas supply portfolio. This point can be underscored through a hypothetical. If the LNG facilities in North Carolina are unable to perform during peak periods, Piedmont would require incremental gas supply and upstream transmission pipeline capacity, almost assuredly at a higher cost than long-term gas contracts, which would then be recorded as costs recoverable through the gas supply portfolio and shared between both North Carolina and South Carolina. The inverse is also true; the LNG facilities' operation allows Piedmont to manage its gas supply costs in a manner that benefits both North Carolina and South Carolina ratepayers.

Appendix A-1 - Public Staff's Comments & Atrium's Responses

Comments and Recommendations of the Public Staff on the June 9, 2023, Draft of the Piedmont Natural Gas Cost Allocation and Regression Review by Atrium Economics

Based on its review of the June 9, 2023, draft of the Piedmont Natural Gas Cost Allocation and Regression Review by Atrium Economics (Draft Report), the Public Staff provides its comments and recommendations below.

The Public Staff notes at the outset that the issues to be studied, as agreed upon by Piedmont Natural Gas Company, Inc. (Piedmont or Company) and the Public Staff, and as ordered by the North Carolina Utilities Commission (Commission) are as follows:

1. Whether the Company's current method of allocating its transmission plant assets to North Carolina and South Carolina is fair to each state's customers in light of the fact that the Company plans for future supply and capacity resources based on a combination of both North Carolina and South Carolina demand;

2. Whether the Company's current regression analysis can be updated to determine a more accurate breakdown of system usage among the Company's customer classes and its North Carolina and South Carolina jurisdictions; and

3. Whether the Company's current allocation of its LNG plant assets between North Carolina and South Carolina is fair to each state's customers in light of the fact that the Company plans for future supply and capacity resources based on a combination of both North Carolina and South Carolina demand.

Section 1.2 Allocation of Transmission Facilities Across Jurisdictions

1. The Draft Report states on page one, "Atrium finds that the LNG facilities benefit North Carolina by reducing required Transmission Capacity investment (cost saving) and boosting capacity through pressure support in eastern North Carolina, thus eliminating the need for reinforcing or expanding the Transmission System (cost saving)."

Public Staff Comments:

The Public Staff does not believe this finding falls within the scope of the issues to be studied, and does not believe Atrium has provided analysis to support this finding. Further, the Public Staff notes that Piedmont's LNG facilities are located throughout the State of North Carolina, not just Eastern North Carolina. Also, the Public Staff notes that compression is a component of demand and one aspect of demand is natural gas electric generators, which have special contracts and do not pay directly for LNG plants.

Public Staff Recommendation:

The Public Staff recommends that Atrium revise this finding to reflect that Piedmont's LNG facilities benefit North Carolina through pressure support in North Carolina and through supplying capacity to North and South Carolina.

Atrium's Response:

The referenced sentence is based on the information provided by Piedmont to Atrium and Public Staff during the information gathering stage of this engagement described in section 2.3.1 of the report, as further detailed in Appendix B – Confidential – Overview of Piedmont's North Carolina and South Carolina Systems. Contrary to Public Staff's opinion, Atrium believes the referenced finding is well within the scope of its review, as the LNG facilities and the Transmission system to which the LNG facilities are connected are interrelated. As described in the section of Appendix B labeled, Overview of Piedmont's LNG Facilities, the Robeson LNG facility was under consideration during a time when the Piedmont transmission pipeline corridor originating at Transco and extending toward eastern North Carolina was capacity constrained as the system approached a Design Day, which would equate to Piedmont's peak winter flow rates. Piedmont evaluated several options to mitigate the capacity constraint. One option was to expand the transmission corridor with pipeline and compression. Piedmont compared the costs and benefits of that option to creating and storing LNG in eastern North Carolina in order to vaporize that LNG during high-demand days when the Piedmont transmission system becomes a bottleneck for eastern North Carolina. Piedmont determined the Robeson LNG facility was the best solution.

Atrium has not analyzed to what degree the LNG facilities reduce required transmission capacity investment. Such an analysis is not required to support Atrium's conclusion that the North Carolina intrastate transmission system should not be allocated to South Carolina, since there are no cost implications for South Carolina relating to any cost causative association between the North Carolina LNG facilities and the North Carolina transmission system. In the instance in which incremental pipeline facilities were required to connect the Robeson LNG facility to the North Carolina transmission system, Atrium indicated the costs could be allocated similar to the LNG facilities (see section 5.5).

Atrium's conclusions relating to the allocation of the Piedmont's LNG facilities is documented in section 7.5 of the report.

2. The Draft Report states on pages one and two, "With regards to the proposal by Public Staff to allocate a portion of the North Carolina transmission system on the average usage by comparison with electric production facilities, the function of LNG facilities differs from that of electric production resources, and using annual usage data for allocation is not recommended."

Public Staff Comments:

The Public Staff has not proposed that Piedmont, a natural gas LDC, be likened to an electric utility on a one-to-one basis. Electric utilities utilize a variety of methodologies to evaluate cost responsibility, including peak demands, average demand, and/or energy. For example, electric transmission is allocated using a demand allocator, but not energy or average demand. The Public Staff believes Atrium evaluated rate design, but not allocation proxies.

Public Staff Recommendation:

Because this finding is based on a misinterpretation of the Public Staff's position, and because Atrium did not perform a detailed review of demand and/or production-based cost allocation in the Carolinas, the Public Staff recommends omission of this passage from the final report.

Atrium's Response:

Atrium updated the Report to contain a footnote to the position of Public Staff and clarified the referenced sentence. Atrium's conclusion that using annual usage data for the allocation of these transmission lines does not require a detailed review of demand and/or production-based cost allocation in the Carolinas. Further, Atrium is well versed in the allocation methods used across the United States and is familiar with those methods used across the Carolinas. Further, Public Staff's testimony states, "Therefore, it is apparent that the transmission system is an integral extension of the LNG facilities. I also would like to note that the LNG facilities utilize the transmission system throughout the entire year, and the usage of the transmission system is not isolated to a few discrete days during the winter or system peaking periods." This was directly addressed by Atrium in section 5.4 finding that, "transmission capacity costs are not related to throughput volumes" and that only "0.07% of LNG related volumes [are] associated with South Carolina deliveries."

Section 1.3 Rate Class Regressions

3. The Draft Report states on page two, "It is not appropriate to use the recent experience as a method to allocate costs that were incurred based on design day. Atrium finds that the Company's regression analysis would be improved by using multiple independent variables for the previous and current month's HDDs. Atrium also believes that a regression analysis utilizing multiple years of historical data would improve the stability of the analysis."

Public Staff Comments:

It is not clear whether Atrium is discussing the design day calculation in this passage or the rate class regression within the context of a general rate case. The Public Staff requests that Atrium provide more context and clarity.

Atrium notes that the system is designed to design day, but asserts that the annual regression should be used and not the winter period. The Public Staff understands this as Atrium's recommendation that the system should be designed to a "peak" demand, but that regressions should be based on annual usage. If the Public Staff's understanding is correct, Atrium's recommendation conflicts with how Piedmont determines design day, which is by using only winter data to determine the regression. Atrium's recommendation also conflicts with its statement that "It is not appropriate to use the recent experience as a method to allocate costs," and its recommendation in Section 1.4 of the Draft Report to use the design day peak method.

In addition, the Draft Report does not distinguish what analysis the Company used in the last rate case (i.e., present rates) and how the recommendation may or may not be different than what is already being used.

Public Staff Recommendation:

The Public Staff recommends that, order to resolve the issues discussed above, Atrium omit from the final report the statement "It is not appropriate to use the recent experience as a method to allocate costs that were incurred based on design day," or that Atrium omit the word "not" from the quoted sentence.

Atrium's Response:

As the referenced text is under the heading "Rate Class Regressions", Atrium believes that the context is clear that the discussion is about the rate class regressions.

Regarding the Public Staff's sentence, "The Public Staff understands this as Atrium's recommendation that the system should be designed to a "peak" demand, but that regressions should be based on annual usage.", Atrium does not make a recommendation regarding how the system should be designed, rather Atrium states the fact that natural gas distribution systems are constructed to a design day standard.

Regarding the use of twelve months of data in comparison to only a winter period for regression analysis Atrium is recommending using a regression of all months of the year as it informs determining a base load coefficient because there are months with zero or close to zero HDDs (i.e., more datapoints, or degrees of freedom in statistical terminology), helps inform the relationship between weather and usage). A design day peak is calculated using regression coefficients times design day HDDs and the intercept designates zero HDDs or base load conditions. Atrium further believes that the consistency of the analyses performed as the basis of the Company's normalized billing determinants and its rate class design day allocation is a benefit. Atrium acknowledges that a multi-year winter-period-only regression analysis for design day allocation would likely produce reasonable results, and that these results would not differ substantively from a multi-year regression using twelve months of data in the analysis.

Atrium believes that the distinction made between analyses is clear and without confusion. The draft report explicitly states Atrium's understanding that in the last rate case Piedmont used a 15-15 HDD regression analysis of the test year's twelve months of usage and weather, while the Public Staff advocated actual test year usage data as a representation of design conditions (which it is not). Atrium's recommendations are to consider the use of a previous and current month HDD regression against usage per customer for a period of longer than twelve months.

Section 1.4 Allocation of LNG Facilities Across Jurisdictions

4. The Draft Report states on page three, "Actual usage of the LNG facility varies from year to year, making it less suitable for allocation without multiple years of data. Design Day Peak, which formed the basis for the initial investment and resource planning decisions, is expected to be more consistent across multiple years, making it a more durable allocation method. It is important to note that ancillary pressure support from the LNG facilities benefits only NC customers, and any changes in its usage should be monitored for potential adjustments in the allocation. "

Public Staff Comments:

It is unclear what Atrium means by "multiple years of data." Atrium should clarify whether it is recommending multiple years of winter-only data, or multiple years of annual data, and how many years of data Atrium believes are required.

The Draft Report also does not comprehensively address the benefits of displacement to the Carolinas. The Public Staff also notes that discharging stored LNG mitigates the need to source gas for North Carolina usage from Piedmont city gate on the Transco pipeline and allows supplies to instead be delivered to South Carolina.

Atrium's Response:

Multiple years of monthly data. See our response above to item three.

Regarding the issue of displacement, Atrium edited section 7.5 'Atrium's Findings – Allocation of LNG Facilities Across Jurisdictions' to state our findings more clearly relating to the benefits of displacement. The final report now reads, "The cost efficiencies provided by the LNG facilities in North Carolina allowed Piedmont to redirect a portion of Transco firm pipeline capacity, and peaking supply provided by the LNG facilities, to South Carolina by displacement, thereby avoiding the cost of firming up, at forward haul rates, Transco pipeline capacity formerly firm under FERC back haul provisions."

5. The Draft Report also states on page three, "Atrium recommends relying on rate class regressions for now and suggests that if future resource planning relies on MEA design day estimates; the MEA estimates would be appropriate for the allocation of LNG facilities."

Public Staff Comments:

The MEA design day estimates are not within the scope of the study. The MEA Design Day Study Report is dated July 27, 2022, over six months after the Commission issued its final order in Docket No. G-9, Sub 781, which included the requirement to conduct the three studies that are the subject of the Draft Report. In addition, it is the Public Staff's understanding that Piedmont is still reviewing how the MEA analysis will be utilized in its long-term capacity and supply planning decisions as well as in the planning of Piedmont's distribution and transmission systems.[16]

Public Staff Recommendation:

The Public Staff recommends omission of any discussion of the MEA design day estimates from the final report for the reasons cited above.

Atrium's Response:

The MEA design day estimates were the subject of multiple meetings with Piedmont and Public Staff. Specifically, the MEA design day estimates may provide a viable method to allocate LNG facility costs across NC and SC in the future and should be considered. No changes were made to the report.

Section 5.3 Concerns Raised in Prior Rate Case

[16] See Rebuttal Testimony of Jeffrey Patton and Todd Breece on Behalf of Piedmont Natural Gas Company, Inc. filed in Docket No. G-9, Sub 811 on September 29, 2022.

6. Page 18 of the Draft Report summarizes the Public Staff's and Piedmont's respective positions on the appropriateness of allocating a portion of North Carolina transmission assets to South Carolina rate payers.

Public Staff Comments:

The Public Staff believes the information set out in Section 2.0 provides sufficient background for the studies and is concerned that Section 5.3 does not present the Public Staff's and Piedmont's respective positions in a balanced manner.

Public Staff Recommendation:

For the reasons stated above, the Public Staff recommends that Atrium omit Section 5.3 from the final report.

Atrium's Response:

Atrium included the details in Section 5.3 for completeness of the Report and to ensure any reader can gain a full understanding of the issues that were raised in Docket No. G-9, Sub 781, and resulted in Atrium's investigation, analyses, and conclusions. No changes were made to the report.

Section 5.5 Atrium's Findings – Allocation of Transmission Facilities Across Jurisdictions

7. On pages 20 and 21 of the Draft Report, Atrium continues to reference Eastern North Carolina.

Public Staff Comments:

Atrium's repeated reference to Eastern North Carolina suggests that Atrium did not address the intended scope of the analysis, which was all of North Carolina, and instead focused on just one portion of Piedmont's service territory in North Carolina.

In addition, the Public Staff notes that there are other methods of maintaining pressure (e.g., building new pipelines and compressor station upgrades) that the Draft Report does not address in any detail.

Atrium's Response:

Atrium confirms that the scope of its analysis and the findings in the report relate to all of Piedmont's service territory in North Carolina. To clarify instances of the term 'eastern', the following changes were made:

- Deleted the term 'eastern' on page 1.
- Added the term 'For example, with regard to the Robeson facility' on page 2-3 and page 30.
- Deleted the term 'eastern' on page 20. Deleted the term 'the eastern portion of' and

added 'at least in the case of Robeson' to page 21.

Section 6.5 Atrium's Findings – Rate Class Regressions

8. Figure A-1 shows Atrium's Residential Rate Class Regression Comparison.

Public Staff Recommendation:

The Public Staff requested that Atrium perform additional regression analyses. The Public Staff recommends that Atrium provide the results of those analyses in Figure A-1.

Atrium Response:

Atrium provided the Excel workbook to Public Staff via email on April 19, 2023. In addition, all workpapers are provided with the Final Report.

Section 7.5 Atrium's Findings – Allocation of LNG Facilities Across Jurisdictions

9. The Draft Report states on page 30, "In short, a singular LNG facility of the size built by Piedmont in North Carolina provides economies of scale (i.e., cost per unit of capacity and deliverability) well beyond building two separate smaller LNG facilities in North and South Carolina, notwithstanding the reduced transmission pipeline capacity cost economies afforded the eastern North Carolina service territory from the strategic location."

Public Staff Comments:

The Draft Report does not provide any analysis conducted by Atrium or by Piedmont of the sizing or optimal location of "smaller" LNG facilities.

Public Staff Recommendation:

The Public Staff recommends omission of this section from the final report as no supporting analysis was provided for Atrium's conclusion.

Also, as discussed in the Public Staff's comments on Section 1.4 of the Draft Report, the MEA design day estimates are not within the scope of the studies and should, therefore, be omitted from the final report.

Atrium's Response:

The referenced statement is based on Atrium's experience and no analysis was necessary. Certain LNG facility costs would be duplicated with two locations including, but not limited to, engineering and construction costs related to metering and pressure regulation, liquefication equipment, storage container, vaporization equipment, site acquisition, permitting and development, and interconnection with existing systems. Regarding, the MEA design day estimates please see Atrium's Response to Item 5.

10. The Draft Report states on pages 31 and 32, "Finally, the fundamental approach to allocating the LNG facilities is grounded in the equitable cost sharing through minimizing resource costs through economies of scale and sharing of resources."

Public Staff Comments:

The Public Staff supports cost causation principles and, to the greatest extent possible, the reduction of class/jurisdiction subsidization.

Public Staff Recommendation:

The Public Staff recommends that Atrium provide more detail on resource sharing, economies of scale, and why the current method of cost sharing is equitable.

Atrium's Response:

Section 7.5 Atrium's Findings – Allocation of LNG Facilities Across Jurisdictions discusses resource sharing via displacement and economies of scale supporting Atrium's conclusions.

11. The Draft Report states on page 32, "The inherent risks of performance of these pipeline and LNG resources and the associated financial impacts are also shared between the two jurisdictions according to the allocation methodology underlying the gas supply portfolio."

Public Staff Comments:

This statement is not supported by any analysis or discussion.

Public Staff Recommendation:

For the reason stated above, the Public Staff recommends that this statement be omitted from the final report.

Atrium's Response:
Atrium added an additional sentence to provide further discussion of the referenced statement. No analyses are required to support the statement.

Appendix A-2 – Piedmont's Comments & Atrium's Responses

	Referenced Section & Comment	Atrium Notes
1	Page 3, paragraph one, first sentence: "Pay" should be changed to "Day"	Change made
2	Page 3, paragraph one, first sentence: It's unclear here what is meant by the statement "the past use of LNG facility and regression analysis based on heating degree days as alternatives"	Updated sentence to clarify - see section 7.5 for more details.
3	Page 4, section 2.1.1, first paragraph, second sentence: the word "directly" seems unnecessary in this sentence and should be struck because Piedmont (neither directly nor indirectly) owns any natural gas transmission lines that connect its North Carolina and South Carolina systems.	The word directly reflects the ownership and is not necessary and has been stricken.
4	Page 5, section 2.1.3, last sentence with parenthesis: "regulation" should be changed to "support"	Change made
5	Page 8, section 3.1, second paragraph, second sentence: "relat" should be changed to "relate"	Change made
6	Page 12, section 4.1.1, second paragraph, last sentence: replace "applicable" with "needed to address our customers' best interests"	The word applicable is broad and demonstrates the point without needing an edit.
7	Page 13, section 4.1.2, second paragraph, last sentence: add "and determines how much Piedmont will baseload for the month of flow"	Sentence is not intended to be exhaustive of all use of forecast.
8	Page 13, section 4.1.2, third paragraph, last sentence: insert the phrase "is used to determine/calculate" after the word "demand"	Sentence edited for clarity.
9	Page 13, section 4.1.2, fourth paragraph, last sentence: strike the phrase "current (2022-2023) winter" and replace it with "winter 2022-2023 and upcoming winters"	Change made
10	Page 14, section 4.1.3, third paragraph, first sentence: add "forecasted design" after "colder-than-normal". Add "/demand" after "weather"	The sentence would read: Piedmont also includes a 5% reserve margin to account for force majeure, interruptions, colder-than-normal forecasted design weather/demand, and circumstances outside the normal probability of outcomes from a statistical point of view. Atrium does not find these changes to increase the clarity of the sentence.

11	Page 14 section 4.1.3, fourth paragraph, first sentence: replace the sentence "Piedmont's forecast gas supply is approximately 1.44 BCF on a Deisgn Day scenario." with the sentence "Piedmont's forecasted firm sales demand is approximately 1.44 BCF on a Deisgn Day scenario for the 2022-2023 winter."	Change made
12	Page 14, section 4.1.3, first paragraph: change "prepares" to "prepared"	Change made
13	Page 14, section 4.1.3, fifth paragraph, first sentence: after "individual" add "interstate pipeline". Replace "serving" with "serve"	Change made
14	Page 15, second paragraph, last sentence: add approximately" before "four"; replace "five" with "six"	Atrium acknowledges the period could be longer.
15	Page 15, third paragraph, second sentence: add "scenario/forecast" after "winter"	Added the term 'demand forecast' to clarify sentence.
16	Page 16, fourth paragraph: replace the phrase "when up for renewal or" with the phrase "when up for renewal and/or"	Change made
17	Page 16, paragraph three, last sentence: add "and Piedmont" at the end of the sentence	Change made
18	Page 16, fifth paragraph, last sentence: add at the end of the sentence this phrase "(which includes the cost of gas at the receipt point)."	Change made
19	Page 17, second paragraph: strike the reference to "Raleigh", because that market it not part of Piedmont's service territory.	Change made
20	Page 18, first paragraph: After the phrase "In NC Docket No, G-9, Sub 781", add the statement "and in its prior general rate cases,"	Change made
21	Page 22, fourth paragraph, last sentence: modify sentence to say "For the large volume service rate classes where all customer meters are read from the first of the month to the last day of the month, Piedmont uses calendar month HDDs for the regression analysis."	Change made
22	Page 26, first paragraph, last sentence: strike the phrase "for normalized billing determinants" since that portion of the recommendation in this sentence is outside the scope of this study	Change made. Section 1.3 states that Atrium believes additional issues may arise from using different analyses for design day and normalized billing determinants.
23	Page 27, section 7.2: After the phrase "In NC Docket No, G-9, Sub 781", add the statement "and in its prior general rate cases,"	Change made

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24	Page 30, last paragraph over bullets: “Pay” should be “Day”	Change made
25	Section 7.5: Piedmont refreshes in each NC general rate case the rate class regressions used to develop the Design Day Allocator used for LNG plant and fixed gas costs, effective with new billing rates approved in each NC general rate case. The Company is amenable to developing and presenting an updated computation of the Design Day Allocator utilizing Atrium's recommended methodology from Section 7.5 as part of Piedmont's application in its next NC general rate case.	No edit requested or needed.
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Appendix B - Confidential - Overview of Piedmont's North Carolina and South Carolina Systems

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