NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

September 19, 2022

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. G-9, Sub 811

Dear Ms. Dunston:

In connection with the above-referenced docket, we transmit herewith for filing on behalf of the Public Staff the following:

1. Direct Testimony of Sonja R. Johnson, Financial Manager, Accounting Division;

2. Direct Testimony and Exhibits of Dustin R. Metz, Utilities Engineer, Energy Division; and

3. Direct Testimony and Exhibit of Jordan A. Nader, Utilities Engineer, Energy Division.

By copy of this letter, we are forwarding copies to all parties of record by electronic delivery.

Sincerely,

Electronically submitted
/s/ Elizabeth D. Culpepper
Staff Attorney
elizabeth.culpepper@psncuc.nc.gov

/s/ Megan Jost
Staff Attorney
megan.jost@psncuc.nc.gov

Attachments

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 811

In the Matter of		
Application of Piedmont Natural Gas	)	**TESTIMONY OF**
Company, Inc., for Annual Review of Gas	)	**SONJA R. JOHNSON**
Costs Pursuant to N.C.G.S. § 62.133.4(c)	)	**PUBLIC STAFF –**
and Commission Rule R1-17(k)(6)	)	**NORTH CAROLINA**
	)	**UTILITIES COMMISSION**

PIEDMONT NATURAL GAS COMPANY, INC.

DOCKET NO. G-9, SUB 811

TESTIMONY OF

SONJA R. JOHNSON

ON BEHALF OF

THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 19, 2022

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Sonja R. Johnson. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Financial Manager for Natural Gas and Transportation Section of the Public Staff's Accounting Division.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications and experience are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to: (1) present the results of my review of the gas cost information filed by Piedmont Natural Gas Company, Inc. (Piedmont or Company); in accordance with N.C. Gen. Stat. § 62-133.4(c) and Commission Rule R1-17(k)(6); (2)

provide my conclusions regarding whether the gas costs incurred by Piedmont during the 12-month review period ended May 31, 2022, were properly accounted for; and (3) discuss the Public Staff's investigation and conclusions regarding the prudence of Piedmont's hedging activities during the review period.

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR REVIEW.

A. I reviewed: (1) the testimony and exhibits of the Company's witnesses; (2) the Company's monthly Deferred Gas Cost Account reports; (3) monthly financial and operating reports; (4) the gas supply, pipeline transportation, and storage contracts; (5) the reports filed with the Commission in Docket No. G-100, Sub 24A; and (6) the Company's responses to Public Staff data requests. The data request responses contained information related to Piedmont's gas purchasing philosophies, customer requirements, and gas portfolio mixes. The Public Staff and the Company also had several virtual meetings.

Each month the Public Staff reviews the Deferred Gas Cost Account reports filed by the Company for accuracy and reasonableness, and performs several audit procedures on the calculations, including the following:

(1) Commodity Gas Cost True-Up – The actual commodity gas costs incurred are verified, the calculations and data supporting the

commodity gas costs collected from customers are checked, and the overall calculation is reviewed for mathematical accuracy;

(2) Fixed Gas Cost True-Up – The actual fixed gas costs incurred are compared with pipeline tariffs and gas contracts, the rates and volumes supporting the calculation of collections from customers are verified, and the overall calculation is reviewed for mathematical accuracy;

(3) Negotiated Losses – Negotiated prices for each customer are reviewed to ensure that the Company does not sell gas to the customer below the cost of gas to the Company or below the price of the customer's alternative fuel;

(4) Temporary Increments and/or Decrements – Calculations and supporting data are verified for the collections from and/or refunds to customers that have occurred through the Deferred Gas Cost Accounts;

(5) Interest Accrual – Calculations of the interest accrued on the various deferred account balances during the month are verified in accordance with N.C.G.S. § 62-130(e) and the Commission's Order Approving Merger Subject to Regulatory Conditions and Code of Conduct issued September 29, 2016, in Docket Nos. G-9, Sub 682, E-2, Sub 1095, and E-7, Sub 1100 (Merger Order);

(6) Secondary Market Transactions – The secondary market transactions conducted by the Company are reviewed and verified to the financial books and records, asset management arrangements, and other deferred account journal entries;

(7) Uncollectibles – The Company records a journal entry each month in the Sales Customers' Only Deferred Account for the gas cost portion of its uncollectibles write-offs. The calculations supporting those journal entries are reviewed to ensure that the proper amounts are recorded; and

(8) Supplier Refunds – Unless ordered otherwise, supplier refunds received by Piedmont should be flowed through to ratepayers in the All Customers' Deferred Account or, in certain circumstances, applied to the NCUC Legal Fund Reserve Account. Documentation is reviewed to ensure that the proper amount is credited to the correct account in a timely fashion.

Q. HAS THE COMPANY PROPERLY ACCOUNTED FOR ITS GAS COSTS DURING THE REVIEW PERIOD?

A. Yes.

ANALYSIS OF GAS COSTS

Q. HOW DOES THE COMPANY'S FILED GAS COSTS FOR THE CURRENT REVIEW PERIOD COMPARE WITH THOSE FOR THE PRIOR REVIEW PERIOD?

A. As shown in Tomlinson Exhibit_(MBT-1), Schedule 1, the Company filed total gas costs of $415,672,939 for the current review period as compared with $296,068,509 for the prior twelve-month review period. The components of the filed gas costs for the two periods are as follows:

	12 Months Ended		Increase	%
	May 31, 2022	May 31, 2021	(Decrease)	Change
Demand & Storage	$148,828,701	$140,936,239	$7,892,462	5.6%
Commodity	307,719,348	189,219,220	$118,500,128	62.6%
Other Costs	($40,875,109)	($34,086,950)	($6,788,159)	19.9%
Total	$415,672,939	$296,068,509	$119,604,430	40.4%

Q. PLEASE EXPLAIN ANY SIGNIFICANT INCREASES OR DECREASES IN DEMAND AND STORAGE CHARGES.

A. The Demand and Storage Charges for the current review period and the prior twelve-month review period are as follows:

		Actual Amounts for the 12 Month Periods Ended			
				Increase	%
		April 30,2022	April 30,2021	(Decrease)	Change
Transco	FT	$100,254,972	$101,790,787	($1,535,815)	(1.5%)
Transco	GSS	4,073,323	4,048,876	24,447	0.6%
Transco	ESS	2,965,975	3,014,126	(48,150)	(1.6%)
Transco	WSS	2,187,014	2,198,540	(11,525)	(0.5%)
Transco	LNG Servi	650,182	650,182	-	0.0%
Columbia	Firm Stora	6,911,138	4,500,498	2,410,640	53.6%
Columbia	SST	8,637,966	6,637,721	2,000,245	30.1%
Columbia	FTS	4,502,954	3,343,945	1,159,009	34.7%
Columbia	No Notice	1,391,880	1,152,604	239,276	20.8%
Dominion	GSS	596,164	575,584	20,580	3.6%
Dominion	FT - GSS	944,333	960,704	(16,372)	(1.7%)
ETN	FT	4,856,110	4,645,440	210,670	4.5%
Texas Eastern		796,976	796,976	-	0.0%
Midwestern	FT	1,069,200	1,069,200	-	0.0%
Hardy Storage		18,015,139	15,582,884	2,432,255	15.6%
Pine Needle LNG		7,409,584	7,359,425	50,159	0.7%
Cardinal	FT Deman	6,209,018	6,206,644	2,373	0.0%
LNG Processing		2,940,807	787,801	2,153,006	273.3%
Property Taxes		29,559	18,559	11,000	59.3%
Other		0	0	-	-
NC/SC Costs Expensed		174,442,294	165,340,496	9,101,798	5.5%
NC Demand Allocator		85.32% 1/	85.24%		
NC Costs Expensed		$148,828,701	$140,936,239	$7,892,462	5.6%

1/ Weighted average demand allocator due to change in rate case effective November 1, 2021.

Note: Actual amounts lag one-month behind the accounting period. The May 31 review periods reflect actual amounts for the 12-month

The decreases in the **Transcontinental Gas Pipe Line Company, LLC (Transco) Firm Transportation (FT), the Transco Eminence Storage Service (ESS), the Transco Washington Storage Service (WSS), and Dominion FT - GSS** charges are due to decreases related to Transco's general rate case and fuel tracker filings pursuant to FERC Docket Nos. RP21-1160-000 and RP21-579-000, effective November 1, 2021, and April 1, 2021, respectively, which were in effect during the current review period.

The increase in the **Columbia Gas Transmission, LLC (Columbia), Firm Storage Service, Columbia Storage Service Transportation (SST), Columbia Firm Transportation Service (FTS), and No Notice Transportation FT Service** charges is due to a general rate case filing in FERC Docket No. RP20-1060-000, effective February 1, 2021, and a Capital Cost Recovery Mechanism compliance filing under Columbia's Modernization Program in FERC Docket No. RP22-654-000, effective April 1, 2022.

The **East Tennessee Natural Gas (ETN) FT** charges increased due to various FERC amendments involving filings with ETN and Texas Eastern Transmission, LP (TETCO), including rate increases from a TETCO Section 4 general rate case proceeding in FERC Docket No. RP21-1001-003, effective February 1, 2022.

The **Hardy Storage** charges increased by 15.6% as a result of changes in tariff rates in several Modernization Cost Recovery Mechanism (MCRM) FERC filings as well as a supplier refund issued to the Company in April 2022.

The **Liquefied Natural Gas (LNG) Processing** charges are the electric bills associated with the liquefaction expense for Piedmont's three on-system LNG facilities. These charges increased as a result of a higher level of LNG withdrawal volumes when compared to the withdrawal volumes from the prior review period due to the addition of the Robeson County LNG facility being included in Piedmont's supply and capacity portfolio.

The increase in **Property Taxes** for the current review period is due to the inclusion of an improperly excluded property tax bill in the prior review period that was corrected during the current review period. A corrective journal entry was made in July 2021 and recorded to the deferred account to properly account for the interest.

Q. PLEASE EXPLAIN THE CHANGE IN COMMODITY GAS COSTS.

A. Commodity gas costs for the current review period and the prior twelve-month review period are as follows:

	Actual Amounts for the 12 Month Periods Ended			
	April 30, 2022	April 30, 2021	Increase (Decrease)	% Change
Gas Supply Purchases	$372,958,391	$215,808,826	$157,149,565	72.8%
Reservation Charges	7,130,598	4,314,080	2,816,518	65.3%
Storage Injections	(85,673,782)	(35,336,498)	(50,337,284)	142.5%
Storage Withdrawals	77,407,071	40,957,517	36,449,554	89.0%
Electric Compressor Costs	2,226,290	1,937,100	289,190	14.9%
Banked Gas Usage	(5,380)	(10,126)	4,746	(46.9%)
Cash Out Brokers (Long)	2,335,054	1,726,180	608,874	35.3%
NC/SC Commodity Costs	$376,378,242	$229,397,079	$146,981,163	64.1%
NC Commodity Costs	$307,719,348	$189,219,220	$118,500,128	62.6%
NC Dekatherms Delivered	69,831,424	73,026,991	(3,195,567)	(4.4%)
NC Cost per Dekatherm	$4.4066	$2.5911	$1.8155	70.1%

Note: Actual amounts lag one-month behind the accounting period. The May 31 review periods reflect actual amounts for the 12-months ended April 30.

Gas Supply Purchases increased by $157,149,565 primarily due to a higher level of wellhead gas prices in the current review period compared to the prior review period, even while delivered volumes decreased.

Reservation Charges are fixed or minimum monthly charges a local distribution company (LDC) may pay a supplier in connection with the supplier providing the LDC an agreed-upon quantity of gas, regardless of whether or not the LDC takes it. The increase in reservation charges reflects a market-driven increase in prices in the current review period as compared to the prior review period.

The increase in **Storage Injections** is due to both a higher cost of gas supply injected into storage and increased volumes injected into storage. The average cost of gas injected into storage during the current review period was $3.9240 per dt as compared with $1.9560 per dt for the prior period. Piedmont injected 21,833,460 dts into storage in the current review period as compared to 18,065,354 dts for the prior period.

The increase in **Storage Withdrawals** reflects both a higher average cost of supply withdrawn from storage and higher volumes withdrawn from storage. Piedmont's average cost of gas withdrawn was $3.5351 per dt for this review period as compared to $2.1790 per dt in the prior period. Piedmont withdrew 21,896,446 dts from storage in the current review period as compared to 18,796,497 dts for the prior period.

Electric Compressor Costs are associated with electric compressors related to power generation contracts. There is no impact on the deferred accounts since these costs are recovered through contract payments.

Banked Gas Usage is the cost of gas associated with the month-end volume imbalances that are not cashed out with customers. Piedmont currently has four banked gas customers, all former NCNG customers, who may exercise the right per contract to carry forward their monthly volume imbalances instead of cashing out monthly. The change in the banked gas represents the difference in the cost of gas supply of the volume imbalances carried forward from month to month.

Cash Out Brokers (Long) represents the purchases made by Piedmont from brokers that brought too much gas to the city gate. The increase in Cash Out Brokers (Long) was due to the increase in volumes purchased during the current review period as compared to the prior review period. During the current review period, the volumes purchased from Cash Out Brokers (Long) was 1,690,318, while the previous review period's volumes purchased was 1,670,091.

Q. PLEASE EXPLAIN THE CHANGE IN OTHER GAS COSTS.

A. Other gas costs for the current review period and the prior twelve-month review period are as follows:

	Actual Amounts for the 12 Month Periods Ended		
	April 30, 2022	April 30, 2021	Increase (Decrease)
Total Deferred Acct Activity COG Items	($23,689,266)	($16,411,813)	($7,277,453)
Actual vs. Estimate Reporting Month Adj.	9,960,129	2,440,975	7,519,154
Total Other Costs	(27,145,971)	(20,116,112)	(7,029,859)
Total NC Other Cost of Gas Expense	($40,875,109)	($34,086,950)	($6,788,159)

Total Deferred Acct Activity COG Items reflect offsetting journal entries for the cost of gas recorded in the Company's Deferred Gas Cost Accounts during the review periods. This amount includes offsetting journal entries for the commodity true-up, fixed gas cost true-up, negotiated losses, and increments/(decrements).

Actual vs. Estimate Reporting Month Adj. amounts result from the Company's monthly accounting closing process. Each month, the Company estimates its current month's gas costs for financial reporting purposes and adjusts the prior month's estimate to reflect the actual cost incurred for that month.

Total Other Costs are primarily the North Carolina ratepayers' portion of capacity release margins and the allocation factor differential for bundled sales. The allocation factor differential is due to the utilization of the NC/SC sales allocation factor in the commodity gas cost calculation and the demand allocation factor utilized in the secondary market calculation.

SECONDARY MARKET ACTIVITIES

Q. PLEASE SUMMARIZE THE COMPANY'S SECONDARY MARKET ACTIVITIES DURING THE REVIEW PERIOD.

A. During the review period, the Company earned actual margins of $78,491,679 on secondary market transactions, and credited the All Customers' Deferred Account in the amount of $52,494,333 (($78,491,679 – 100% Duke secondary market sales) x (NC demand allocator x 75% ratepayer sharing percentage) + (100% Duke secondary market sales x NC demand allocator)) for the benefit of ratepayers, in accordance with the Commission's Order Approving Stipulation issued on December 22, 1995, in Docket No. G-100, Sub 67. This dollar amount is slightly different from the amount recorded on Tomlinson Exhibit_(MBT-1), Schedule 9, since the Company's deferred account includes estimates for the May 2022 secondary market transactions. Presented below is a chart that compares the actual Total Company margins earned by Piedmont on the various types of secondary market transactions in which it was engaged during the review period and the prior review period.

	Actual Amounts for the 12 Month Periods Ended			
	April 30, 2022	April 30, 2021	Increase (Decrease)	% Change
Asset Management Arrangements	20,870,389	18,312,648	$2,557,741	14.0%
Capacity Releases	23,638,737	15,465,438	8,173,299	52.8%
Off System Sales	33,982,553	10,333,778	23,648,775	228.8%
Total Company Margins on Secondary Market Transactions	$78,491,679	$44,111,864	$34,379,815	77.9%

Note: Actual amounts lag one-month behind the accounting period. The May 31 review periods reflect actual amounts for the 12-months ended April 30.

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Asset Management Arrangements (AMAs), according to the FERC,[1] are contractual relationships in which a party agrees to manage gas supply and delivery arrangements, including transportation and storage capacity, for another party. Typically, a shipper holding firm transportation and/or storage capacity on a pipeline or multiple pipelines temporarily releases all or a portion of that capacity along with associated gas production and gas purchase agreements to an asset manager. The asset manager uses that capacity to serve the gas supply requirements of the releasing shipper. When the capacity is not needed for that purpose, it is used to make releases or bundled sales to third parties.

Piedmont had seven AMAs during the current review period and the prior review period. The 14.0% increase in net compensation from AMAs is due to an increase in the value of the interstate

[1]Promotion of a More Efficient Capacity Release Market, Order No. 712, 123 FERC ¶ 61,286, Paragraph 110 (June 19, 2008).

pipeline and storage capacity that Piedmont has subject to the AMAs.

Capacity Releases are the short-term postings of unutilized firm capacity on the electronic bulletin board that are released to third parties at a biddable price. The overall net compensation from capacity release transactions primarily increased due to a higher level of released volumes as well as a higher value being received for the capacity as compared to the previous period.

Off System Sales on Piedmont's system are also referred to as bundled sales. Bundled sales are gas supplies delivered to a third party at a specified receipt point in the Transco market area. Because bundled sales move gas from the production area to the market area, these sales involve both gas supply and pipeline capacity. The net compensation from off system sales increased during the current review period by approximately 228.8% as compared to the prior review period. This was due to an increased level of off system sale transactions entered into during the current review period as compared to the prior period, as well as an increase in the value of the transactions.

Q. PLEASE PROVIDE A FURTHER DESCRIPTION OF PIEDMONT'S OFF SYSTEM SALES TRANSACTIONS.

A. During the current review period, Piedmont entered into multi-month and daily off system sales transactions with approximately 35 shippers. Approximately 32% of these off system sales transaction volumes consisted of daily transactions and 68% were multi-month transactions.

HEDGING ACTIVITIES

Q. PLEASE EXPLAIN HOW THE PUBLIC STAFF CONDUCTED ITS REVIEW OF THE COMPANY'S HEDGING ACTIVITIES.

A. The Public Staff's review of the Company's hedging activities is performed on an ongoing basis and includes the analysis and evaluation of the following information:

(1) The Company's monthly hedging deferred account reports;

(2) Detailed source documentation, such as broker statements, that provide support for the amounts spent and received by the Company for financial instruments;

(3) Workpapers supporting the derivation of the maximum hedge volumes targeted for each month;

(4) Periodic reports on the status of hedge coverage for each month (Hedging Position Report);

(5) Periodic reports on the market values of the various financial instruments used by the Company to hedge (Mark-to-Market Report);

(6) The monthly Hedging Program Status Report;

(7) The monthly report reconciling the Hedging Program Status Report and the hedging deferred account report;

(8) Minutes from meetings of Piedmont's Gas Market Risk Committee;

(9) Minutes from the Board of Directors and its committees pertaining to hedging activities;

(10) Reports and correspondence from the Company's external and internal auditors pertaining to hedging activities;

(11) Hedging plan documents that set forth the Company's gas price risk management policy, hedge strategy, and gas price risk management operations;

(12) Communications with Company personnel regarding key hedging events and plan modifications under consideration by Piedmont's Gas Market Risk Committee; and

(13) Testimony and exhibits of the Company's witnesses in the annual review proceeding.

Q. WHAT IS THE STANDARD SET FORTH BY THE COMMISSION FOR EVALUATING THE PRUDENCE OF A COMPANY'S HEDGING DECISIONS?

A. In its February 26, 2002 Order on Hedging in Docket No. G-100, Sub 84 (Hedging Order), the Commission stated that the standard for reviewing the prudence of hedging decisions is that the decision "must have been made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or should have been known at that time." Hedging Order at 11-12.

Q. PLEASE DESCRIBE THE ACTIVITY REPORTED IN THE COMPANY'S HEDGING DEFERRED ACCOUNT DURING THE REVIEW PERIOD.

A. The Company experienced net benefits of $18,021,467 in its Hedging Deferred Account during the review period. This net benefit amount in the account as of May 31, 2022, is composed of the following items:

Economic (Gain)/Loss - Closed Positions	(18,106,560)
Premiums Paid	345,980
Brokerage Fees & Commissions	11,612
Interest on Hedging Deferred Account	(272,499)
Hedging Deferred Account Balance	($18,021,467)

The Company proposed that the ($18,021,467) credit balance in the Hedging Deferred Account as of the end of the review period be transferred to its Sales Customers' Only Deferred Account.

The first item shown in the chart above, Economic (Gain)/Loss - Closed Positions, is the gain on hedging positions the Company realized during the review period. Premiums Paid is the amount spent by the Company on futures and options positions during the current review period for contract periods that closed during the review period or that will close after May 31, 2022. As of May 31, 2022, this amount includes call options purchased by Piedmont for the May 2023 contract period, a contract period that is 12 months beyond the end of the current review period and 12 months beyond the May 2022 prompt month. Brokerage Fees and Commissions are the amounts paid to brokers to complete the transactions. The Interest on Hedging Deferred Account is the amount accrued by the Company on its Hedging Deferred Account in accordance with N.C.G.S. § 62-130(e) and the Merger Order, effective October 1, 2017.

The hedging costs incurred by the Company during the review period represent approximately (4.34%) of total gas costs or ($0.2581) per dt. The average monthly cost per residential customer for hedging is approximately ($1.27) per dt.

Q. DID THE COMPANY MODIFY ITS HEDGING PLAN DURING THE REVIEW PERIOD?

A. No. The Company did not modify its hedging plan during the current review period.

Q. WHAT IS YOUR CONCLUSION REGARDING THE PRUDENCE OF THE COMPANY'S HEDGING ACTIVITIES?

A. Based on the Public Staff's analysis and what was reasonably known or should have been known at the time the Company made its hedging decisions affecting the review period, as opposed to the outcome of those decisions, I conclude that the Company's decisions were prudent. I recommend that the ($18,021,467) credit balance in the Company's Hedging Deferred Account as of the end of the review period be transferred to Piedmont's Sales Customers' Only Deferred Account.

DEFERRED ACCOUNT BALANCES

Q. BASED ON YOUR REVIEW OF GAS COSTS IN THIS PROCEEDING, WHAT ARE THE APPROPRIATE DEFERRED ACCOUNT BALANCES AS OF MAY 31, 2022?

A. The appropriate All Customers' Deferred Account balance is a credit balance of $36,906,871, owed by the Company to the customers, as filed by the Company.

The appropriate Sales Only Customers' Deferred Account balance is a debit balance of $32,917,295, owed by the customers to the Company, as filed by the Company.

The Public Staff recommends transferring the credit balance of ($18,021,467) in the Hedging Deferred Account as of the end of the review period to the Sales Customers' Only Deferred Account. The recommended balance for the Sales Customers' Only Deferred Account as of May 31, 2022, is a net debit balance owed to the Company of $14,895,828, determined as follows:

Balance per Exhibit MBT-1 Sch 8	$32,917,295
Transfer of Hedging Balance	(18,021,467)
Balance per Public Staff	$14,895,828

Q. HAS THE COMPANY APPLIED THE CORRECT INTEREST RATE IN THE DEFERRED ACCOUNTS?

A. Yes. The Company's requirement regarding the appropriate interest rate to use in the deferred gas cost accounts was established in the Merger Order. Ordering Paragraph 9 of the Merger Order states that

> [B]eginning with the month in which the merger closes, Piedmont shall use the net-of-tax overall rate of return from its last general rate case as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in its Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts.

The Public Staff believes that the Company has complied with Ordering Paragraph 9 of the Merger Order.

Q. WHAT IS THE PUBLIC STAFF'S POSITION REGARDING CHANGES IN THE INTEREST RATE APPLIED TO PIEDMONT'S DEFERRED ACCOUNTS?

A. The Public Staff believes that any changes in the overall rate of return from a general rate case and in the federal and state income tax rates should lead to changes in the interest rate. As stated earlier in my testimony, each month the Public Staff reviews the Deferred Gas Cost Account reports filed by the Company for accuracy and reasonableness, and performs several audit procedures on the calculations, including, but not limited to, the interest calculations. During the first seven months of the review period, June 1, 2021, through December 31, 2021, Piedmont utilized an interest rate of 6.66% consistent with the net-of-tax overall rate of return from its general rate case in Docket No. G-9, Sub 743. During the remaining five months of the review period, January 1, 2022, through May 31, 2022, the Company utilized an interest rate of 6.45% consistent with the net-of-tax overall rate of return from its general rate case in Docket No. G-9, Sub 781.

The Public Staff has reviewed the Company's interest rate calculations and found that it was appropriate for Piedmont to use the 6.66% and 6.45% interest rates. The Public Staff will continue to review the interest rate each month to determine if an adjustment is needed.

OTHER ISSUES

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS?

A. Yes. Given the volatility of natural gas prices experienced over the past 12 months, the Public Staff recommends that Piedmont, as part of its testimony in the next review period, provide the Commission with detailed testimony and analysis as to how the Company mitigated and/or stabilized the current volatility in gas prices for the benefit of ratepayers utilizing hedging, secondary market transactions, and supply and capacity contracts, including, but not limited to, changes or renegotiations in any of the above based on the volatility of the market.

Q. DOES THIS CONCLUDE THE PUBLIC STAFF'S TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

SONJA R. JOHNSON

I am a graduate of North Carolina State University with Bachelor of Science and Master of Science degrees in Accounting. I was initially an employee of the Public Staff from December 2002 until May 2004 and rejoined the Public Staff in January 2006. I became the Accounting Division's Financial Manager for Natural Gas and Transportation in May 2022.

As a Financial Manager, I am responsible for the performance and supervision of the following activities: (1) the examination and analysis of testimony, exhibits, books and records, and other data presented by utilities and other parties under the jurisdiction of the Commission or involved in Commission proceedings; and (2) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings.

Since joining the Public Staff in December 2002, I have filed testimony or affidavits in several water and sewer general rate cases. I have also filed testimony in applications for certificates of public convenience and necessity to construct water and sewer systems and noncontiguous extension of existing systems. My experience also includes filing affidavits in several fuel clause rate cases and Renewable Energy and Energy Efficiency Portfolio Standard (REPS) cost recovery cases for the utilities currently organized as Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Virginia Electric and Power Company d/b/a Dominion North Carolina Power. I have performed numerous audits and/or presented testimony and exhibits before the Commission addressing a wide range of natural gas topics.

While away from the Public Staff, I was employed by Clifton Gunderson, LLP. My duties included the performance of cost report audits of nursing homes, hospitals, federally qualified health centers, intermediate care facilities for the mentally handicapped, residential treatment centers and health centers.

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PIEDMONT NATURAL GAS COMPANY, INC.

DOCKET NO. G-9, SUB 811

TESTIMONY OF

DUSTIN R. METZ

ON BEHALF OF

THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 19, 2022

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am an engineer in the Electric Section – Operations and Planning of the Public Staff's Energy Division.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications and experience are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide the Commission with a summary of my review and investigation of the design day (DD) demand requirements and capacity planning of Piedmont Natural Gas Company, Inc. (Piedmont or Company).

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. I summarize the activities of the Public Staff and Piedmont in response to the Commission's Order On Annual Review of Gas Costs issued on December 22, 2021, in Docket No. G-9, Sub 791 (Sub 791 Order), the Company's previous annual review proceeding, to address the Company's design day (DD) planning. I conclude that the Piedmont Natural Gas Company Design Day Study Report prepared by Marquette Energy Analytics (MEA) at the request of Piedmont in response to the Sub 791 Order (MEA Report)[1] is inconclusive, and it is not clear how Piedmont used the MEA Report. Therefore, I recommend that the Company promptly determine a final DD planning methodology and provide the results in next year's annual review proceeding.

Q. DID YOU FILE TESTIMONY IN PIEDMONT'S PREVIOUS ANNUAL REVIEW?

A. Yes. On October 1, 2021, I filed joint testimony with Utilities Engineer James M. Singer and then Staff Accountant Sonja R. Johnson in the Sub 791 docket. My testimony specifically addressed Piedmont's DD demand requirement study and made recommendations for the Company's future annual review proceedings.

[1] The MEA Report is attached hereto as Public Staff Metz Exhibit 1.

Q. DID THE COMMISSION AGREE WITH YOUR RECOMMENDATIONS REGARDING THE COMPANY'S DD DEMAND METHODOLOGY IN THE SUB 791 ORDER?

A. Yes. In the Evidence and Conclusions for Finding of Fact Nos. 12-16 the Commission stated as follows:

> The Commission also directs Piedmont to work with the Public Staff prior to filing its next annual review to consider, and possibly implement, the refinements to the Company's design day demand methodology, and to include in its direct testimony next year an update on its discussions with the Public Staff regarding the Company's design day demand estimation methodology and Design Winter Load Duration Curve calculations. The Commission further directs the Company to include a description of any changes Piedmont has made to its demand forecasting and capacity planning as a result. The Commission finds it would serve the interests of everyone to reach resolution on these topics, and the matter of continued evaluation is uncontested between the Public Staff and Piedmont.

Sub 791 Order at 13.

Ordering Paragraphs 7 and 8 of the Sub 791 Order state:

> 7. That Piedmont and the Public Staff shall work together to address, and to the extent practicable, resolve and incorporate within Piedmont's next annual review filing in 2022, the five refinements to the Company's design day demand methodology identified by Public Staff witness Metz in the Public Staff Panel testimony;
>
> 8. That Piedmont shall include an update on its discussions with the Public Staff regarding the Company's design day demand estimation methodology and Design Winter Load Duration Curve calculations, and include a description of any changes Piedmont has made to its demand forecasting and

> capacity planning as a result of these discussions in its direct testimony in its next annual review filing in 2022[.]

Id. at 15.

Q. PLEASE PROVIDE A SYNOPSIS OF THE MEETINGS BETWEEN PIEDMONT AND THE PUBLIC STAFF IN RESPONSE TO ORDERING PARAGRAPH 7.

A. With regard to the Company's DD planning methodology used in the 2020-2021 review period, the Public Staff notified Piedmont of additional issues the Public Staff believed should be evaluated in the current annual review proceeding, including the Company's: (1) regression to highest usage events; (2) system response at different temperatures; (3) risk evaluation for design conditions; and (4) design to an average of the top events and not the absolute worst event. The Public Staff and Piedmont met four times between March and May of 2022. On May 22, 2022, Piedmont advised the Public Staff that it had decided to utilize MEA to perform the DD study and that MEA would look at the broader topic of system planning, not just DD planning. On July 27, 2022, Piedmont provided the MEA Report to the Public Staff. On July 28, 2022, Piedmont, MEA, and the Public Staff had a technical meeting during which MEA provided a presentation titled Piedmont Natural Gas Design Day Study & Forecast (MEA Presentation), which is attached hereto as Public Staff Metz Exhibit 2.

Given the number and magnitude of new elements[2] utilized by MEA in its analysis, as well as the cumulative impact of new capacity identified, it was impossible for the Public Staff to review and provide feedback on the new modeling techniques deployed by MEA in the four calendar days between the Public Staff's receipt of the MEA Report and Piedmont's filing in this proceeding. While MEA's insight and advanced analytics were informative, more research and analysis are necessary before the Public Staff can have an informed opinion.

Q. PLEASE PROVIDE A SUMMARY OF THE JULY 28, 2022 TECHNICAL MEETING BETWEEN MEA, THE COMPANY, AND THE PUBLIC STAFF.

A. The most significant issue discussed was the material changes to the DD calculation resulting from the modification to the DD temperature. Piedmont's initial methodology used 8.69 (not wind adjusted) degrees Fahrenheit, which is a simple average of the high and low temperature on the historic absolute coldest day. The Public Staff recalculated the DD temperature, aligning it to gas day and hourly averages, resulting in a temperature of 12.71 (not wind

[2] The new elements utilized by MEA in its analysis are wind adjusted temperatures, changes in weather station weighting, synthetic (artificial) weather distribution shapes, multiple model runs for load duration curve analysis, study criteria, and recommendations.

adjusted) degrees Fahrenheit for the same day.[3] MEA's methodology calculated a temperature of 6.7 (wind adjusted) degrees Fahrenheit for purposes of DD planning.

MEA's research, including the wind factor adjustment, resulted in its use of January 20, 1985, as the coldest day, versus January 21, 1985, the date utilized by both the Company and the Public Staff. With that insight and adjusting to the same time intervals as gas day for January 20, 1985, my recalculation resulted in a temperature of 6.37 (not wind adjusted) degrees Fahrenheit, compared to the 12.71 degrees Fahrenheit stated previously.[4]

MEA's methodology for determining a wind adjusted design temperature is more advanced than solely considering historical ambient temperatures. In other words, the MEA methodology plots a curve of wind adjusted temperatures on a system weighted basis[5] against the number of temperature occurrences, and then overlays a distribution curve on those results to determine the percentage of times the wind adjusted temperature occurred.

[3] Both of these methods utilized the January 21, 1985 cold weather event, but did not account for wind temperature (i.e., wind chill) correction.

[4] Some weather station data was not readily available and the data for some hours was erroneous. My analysis accounted for these observations and adjusted to the nearest weather station.

[5] MEA's system weighting goes well beyond the scope of the weighting methodology Piedmont has historically utilized in its DD analysis.

This process is illustrated in the graphs from the MEA Presentation shown below. Figure 1 shows the temperature distribution for the last 73 years of winter data.

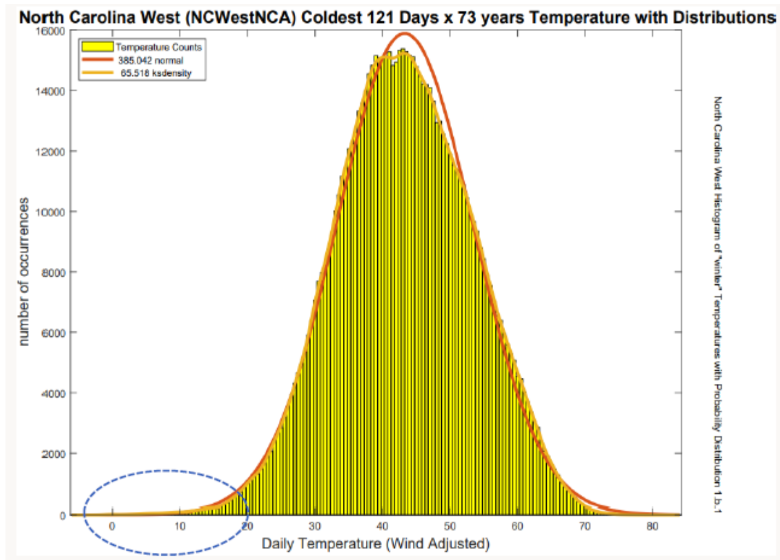

Figure 1: Total Synthetic Distribution

Figure 2 is a detailed view of the blue oval appearing on the far-left x-axis on Figure 1. Note that the far left of the x-axis starts at near zero degrees. The graph then overlays a percentage curve, highlighting the percentage of times that the weighted temperature occurred historically.

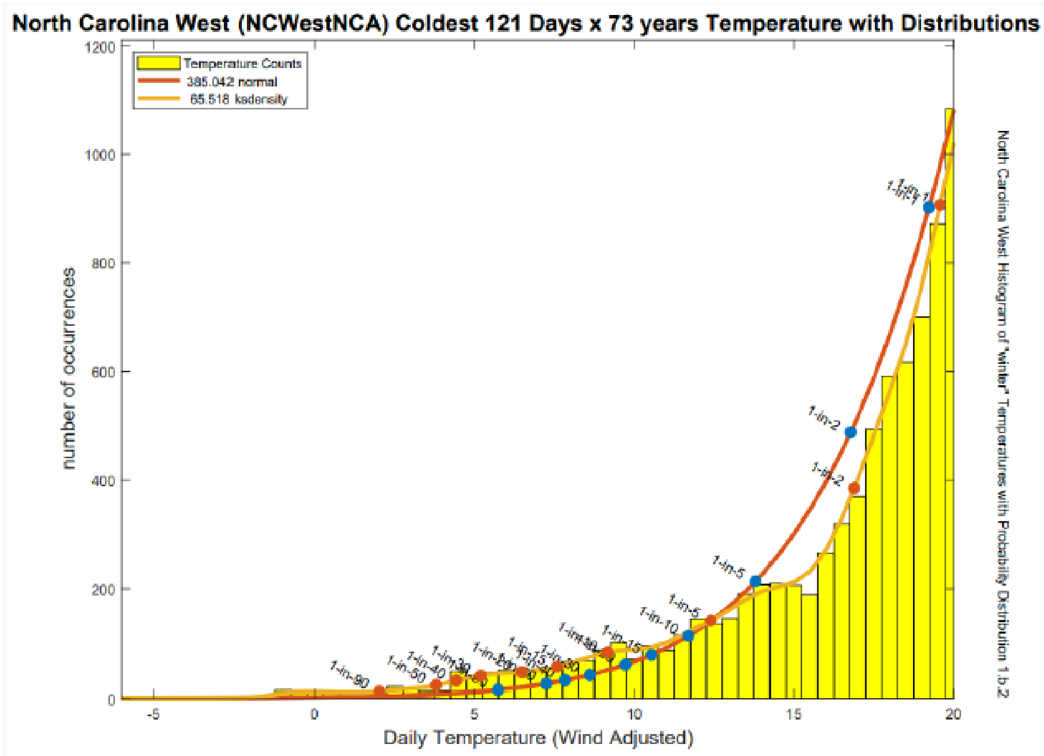

Figure 2: Coldest Temperature Synthetic Distribution

The "1-in-'x'" labels for the blue and red points denote the percentage of times an occurrence has taken place. For example, a 1-in-100-year storm is not really one storm that occurred in 100 years; it is simply an expression to denote that the storm has a 1% chance of occurring in any given year.

I believe MEA is statistically correct in its representation of the data and the chance of occurrence of the temperatures shown in the figure. However, 73 years' worth of data illustrates that the actual occurrence of cold weather events of this magnitude is very rare. This calls into question the reasonableness of basing planning decisions and decisions about adequacy of supply on the MEA representation of historic events.

MEA also used a synthetic load shape to produce complete data.[6] Figure 3 below shows the actual occurrences of cold weather events over the last 73 years.

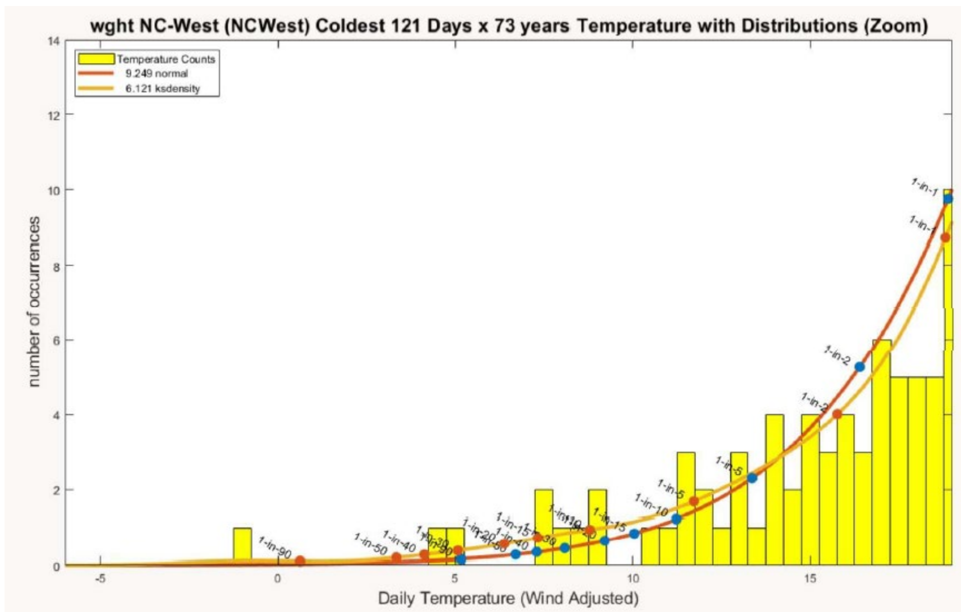

Figure 3: Coldest Temperature Distribution (Actual Events)

The number of historical extreme cold weather events is arrived at using the calculation 73 years x 121 winter days a year = nearly 9000 events. If MEA's, and by extension Piedmont's, DD temperature is accepted as correct, just 3 events out of nearly 9,000 that occurred in Piedmont's Carolinas service territory drive the DD decisions. At

[6] Given the absence of data points, MEA performed a post-processing analysis to fill in the gaps of missing data. This post-processing event may be referred to as a "synthetic" load shape.

this time, I have significant concerns about recommending approval of MEA's proposed "1-in-30" planning criteria given its reliance on a synthetic load shape as opposed to actual occurred system usage data.

Q. PLEASE DISCUSS THE COMPANY'S USE OF RESERVE MARGIN IN ITS RESOURCE PLANNING.

A. Piedmont has historically included a 5% reserve margin in its DD demand calculation to, among other reasons, account for windchill effects on usage across its service territory. Despite the incorporation of MEA's wind-adjusted temperature calculation, the Company has continued its use of the reserve margin in the current annual review. Utilization of MEA's wind adjusted temperature in combination with a 1-in-30 planning criteria seems to duplicate, i.e., double count, cold weather attributes that the Company has used to justify its reserve margin in the past.

Q. TO YOUR KNOWLEDGE, HAS THE COMPANY PERFORMED ANY ANALYSIS TO EVALUATE THE COST IMPACT TO RATEPAYERS OR ANY RELIABILITY ANALYSIS TO MEET THE CAPACITY NEEDS AS DETERMINED BY MEA?

A. No. The Company used MEA's DD temperature and forecasted design peak load for planning purposes for the 2022-2023 winter period in this docket, but has yet to determine if it is necessary for the Company to acquire additional resources in the future as a result of the MEA analysis, or what the impact of such resources would be on the rates paid by its customers.

Q. BASED ON MEA'S RESULTS AND PIEDMONT WITNESS PATTON'S EXHIBITS IN THE CURRENT REVIEW PERIOD, WOULD PIEDMONT'S DD DEMAND SIGNIFICANTLY INCREASE?

A. Yes, which is a significant concern for the Public Staff. An annual increase of approximately 100,000 dekatherms (dts) for design demand purposes is significant as compared to the potential impacts of a capacity shortfall if such an increase were not undertaken. If Piedmont were to use MEA's analysis, as demonstrated in Company witness Patton's Exhibit_(JCP-5C), Piedmont would need new capacity resources, most likely a peaking resource given historic demand response in the last five years. At this time, however, Piedmont has not indicated that it plans to obtain additional peaking resources, nor has it provided adequate analysis and support demonstrating an imminent supply shortfall in the next five-year horizon. If such a supply shortfall is accepted and planned for, a multi-year process will be required to site, design, build, and commission new supply resources (such as an LNG facility). Based on Public Staff discovery submitted to the Company in this proceeding, it is not clear whether Piedmont is adopting MEA's analysis at this time, thus calling into question witness Patton's Exhibit_(JCP-5C) results.

Q. PLEASE SUMMARIZE YOUR CONVERSATION WITH PIEDMONT AND FORMAL DISCOVERY AS IT RELATES TO THE MEA REPORT.

A. The Public Staff served formal discovery on the Company and participated in a teleconference to discuss the Public Staff's concerns with the MEA Report. The Company stated that it continues to evaluate the increased DD requirement and the underlying DD conditions from the MEA analysis, and has not yet determined if it is necessary for the Company to acquire additional resources in the future as a result of the MEA analysis. While Piedmont's testimony and accompanying exhibits make no mention of its future use of the MEA results, the DD planning filed in this proceeding is inconsistent with the Company's statement that it has not yet determined if it needs to acquire additional resources in the future as a result of the MEA analysis.

Q. DOES THE PUBLIC STAFF HAVE ANY CONCERNS OR RECOMMENDATIONS REGARDING THE COMPANY'S FILING?

A. Given Piedmont's annual review filing in Sub 791, coupled with the addition of the Robeson County LNG facility and the Company's transportation contracts in this year's filing, it does not appear to the Public Staff that Piedmont has an immediate capacity shortfall.

I recommend that the Commission order Piedmont to file testimony and accompanying exhibits in next year's annual review proceeding that definitively select a DD plan, a DD temperature, and a reserve margin, and provide sufficient justification for any change. The selection of the DD plan should include: (1) a DD temperature appropriately weighted for the Carolinas service areas; (2) detailed discussion; (3) analysis to support the "1-in-'x'" events planning criteria; and (4) evaluation of loss of service costs versus cost of transportation supply to support the planning reserves.

I also recommend that, given the challenges in this proceeding and the time constraints on the Public Staff's review, Piedmont be required to promptly begin work on the four issues listed above and provide an update to the Commission with preliminary results within six months of the issuance of the Commission's order in this proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associate of Applied Science degrees in Electronics and Electrical Technology (*Magna Cum Laude*) in 2011 and 2012 respectively, and an Associate of Arts in Science in General Studies (*Cum Laude*) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I completed engineering graduate course work in 2019 and 2020 at North Carolina State University.

I have over 12 years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience. My general construction experience includes six years of employment with Framatome, where I provided onsite technical support, craft oversight, and engineer design change packages, as well as participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion. I also worked for six years for an industrial and commercial construction company, where I provided field fabrication and installation of electrical components that ranged from low voltage controls to medium voltage equipment, project planning and coordination with multiple work groups, craft oversight, and safety inspections.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on both electric and natural gas matters including general rate cases, fuel cases, annual gas costs reviews, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations), avoided costs and PURPA, interconnection procedures, integrated resource planning, and power plant performance evaluations. I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

Marquette Energy Analytics

Design Day Demand Study & Forecast

July 27, 2022

Prepared for Piedmont Natural Gas Company
by Marquette Energy Analytics

Piedmont Natural Gas

Piedmont Natural Gas Company
Design Day Study Report

July 27, 2022

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Executive Summary

Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company") retained Marquette Energy Analytics ("MEA") to perform a Design Day Demand Study. The purpose of a design day study and forecast is to determine the quantity of natural gas expected to be used during an extreme cold winter day, a "Design Day".

MEA forecasted Piedmont's Design Day demand for the upcoming 2022-2023 winter, and through the 2026-2027 winter for North Carolina East, North Carolina West, and South Carolina service territories, which sum to the total service territory, or Total Carolinas. The Total Carolinas *Design Day Demand Forecast* for 2022-2023 is 1,444,893 dekatherms ("Dth").

Table 1 – Design Day Forecast (Dth)

Piedmont Design Day Forecast

Design Day Forecast (Dth)	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
North Carolina East	307,058	308,325	310,925	313,317	316,035
North Carolina West	903,072	923,178	944,543	965,262	986,489
South Carolina	234,763	239,835	245,396	250,852	256,391
Total Carolinas	**1,444,893**	**1,471,338**	**1,500,864**	**1,529,431**	**1,558,914**
99% Confidence Forecast	**1,512,026**	**1,538,471**	**1,567,997**	**1,596,564**	**1,626,047**

The assumed weather conditions on a Design Day are the Design Day Conditions ("DDC"). DDC are often stated as a "1-in-N-year" condition, meaning that the condition is expected to occur once every 'N' years. MEA states DDC as a wind-adjusted temperature ("TempW"), or equivalently a Wind-Adjusted Heating Degree Day ("HDDW").

Piedmont elected to use 1-in-30-year DDC which are shown in *Table 2*. The 1-in-30-year DDC is commonly used by Local Gas Distribution Companies ("LDC"), and in fact is the most chosen DDC by LDCs as reported in the AGA publication, *LDC Supply Portfolio Management During the 2018-2019 Winter Heating Season* (Dec. 20, 2019).

The weighted average DDC for Total Carolinas service territory is a wind-adjusted temperature of 6.7°F (HDDW of 58.3), meaning that a wind-adjusted temperature of 6.7°F is expected to occur once every 30 years. Although the individual service territories have different TempW and HDDW, each is a 1-in-30-year DDC for that territory. DDC will be discussed in more detail later in the report.

Table 2 – Design Day Conditions (°F)

1-in-30 Year Design Day Conditions

Service Territory	TempW	HDDW
North Carolina East	9.5	55.5
North Carolina West	5.2	59.8
South Carolina	8.6	56.4
Total Carolinas (wgt. avg.)	**6.7**	**58.3**

This report reviews the details of MEA's design day estimation and forecasting methodology; including the collection of data, the inclusion of wind, calculation of the DDC, detrending of historical demand data to account for customer growth and changes in customer composition and behavior, and the models used to calculate and forecast Design Day demand.

Standard versus 99% Confidence Forecasts

In *Table 1*, the Design Day Demand Forecast is presented in two ways – a standard *Design Day Forecast* of the expected level of demand, and a *99% Confidence Forecast*.

The standard forecast is the expected level of demand if a 1-in-30-year weather event (the DDC) occurs, implying there is a 50% probability that demand will exceed the forecast, and accordingly, a 50% chance that demand will be below the forecast.

The *99% Confidence Forecast* includes an upward adjustment of the *Design Day Forecast* by 2.5 forecast standard deviations, which produces a forecast with an approximately 99% confidence level. This means, if a 1-in-30 weather event occurs (the DDC), there is an 99% probability that actual demand will not exceed the *99% Confidence Forecast*, or alternatively, only a 1% chance that the *99% Confidence Forecast* will be exceeded.

The *99% Confidence Forecast* accounts for factors that are not directly incorporated into the design day forecast, such as prior day effects, as well as other random sources of error. The prior day effect is significant. If a design day occurs "out of nowhere" and the day prior to the design day is much warmer, this will produce a lower demand than if the design day occurs in the middle or end of a string of very cold days.

The *99% Confidence Forecast* is a similar concept to a reserve margin added to a forecast. In this analysis, the Total Carolinas *99% Confidence Forecast* for 2022-2023 is 1,512,026 Dth, or 67,133 Dth (4.65%) greater than the standard 2022-2023 *Design Day Forecast*. The use of the standard *Design Day Forecast* or the *99% Confidence Forecast* depends on the level of reliability needed from the forecast in the event of design day weather conditions.

Marquette Energy Analytics Background

MEA specializes in energy demand modelling, forecasting and analytics, and for over twenty-five years has provided services to more than forty gas distribution companies accounting for over 20% of gas consumption in the United States. Dr. Ronald Brown is the founder of MEA and leads the development of all products and analysis.

Process & Methodology

MEA's design day peak demand forecast is a multi-step analytical process. The analysis and resulting forecast are based on relationships between natural gas demand, and factors including temperature, wind, prior day temperature and wind, day-of-week and day-of-year variables as well as persistent trends in these variables.

A critical component in MEA's analysis is the inclusion of wind in addition to temperature as a factor in modelling demand, recognizing that wind plays a significant role in the demand for natural gas, especially during cold temperatures. MEA calculates wind-adjusted temperature and wind-adjusted Heating-Degree Days ("HDDW") for use the analysis and calculates design day conditions ("DDC") as wind-adjusted temperature and HDDW.

At the inception of a design day study, MEA first acquires and validates all data necessary for the analysis. This includes historical demand data for each service territory, and weather data relevant to the service territory or territories. The weather data, potentially from multiple weather stations, is then optimally weighted to best represent the service territories' demand, and then used to develop the DDC.

MEA then adjusts, or "detrends," historical load data to make past data "look like" current data to ensure that forecasts are based on data that reflects the current customer levels and characteristics. This detrending process adjusts or "normalizes" past data to account for customer growth (or decrease) and changes in baseload and heatload (use per HDDW) demand.

In Piedmont's design day study and forecast, MEA first calculated historical per-customer load from past load and number of customers, then detrended the resulting per-customer load to account for historical changes in per-customer baseload and heatload demand.

In developing the design day demand forecast, MEA uses an ensemble of eight regression models, each considering different factors that affect demand. MEA first calculates an estimate of design day demand for the past winter, then using historical trends in demand uncovered by the regression models, forecasts design day demand to the next winter. The final forecast is a weighted average of the eight individual models. Assumptions about customer growth as well as additional techniques incorporating economic variables are employed to forecast design day demand for the next five winters.

Demand Data

The demand (referred to equivalently as load or sendout) data used in MEA's analysis was provided by Piedmont. MEA's analysis and forecast is of firm sales (FS) loads only, and Piedmont communicated that the provided data appropriately allocates FS customers only their share of LAUF.

Weather Data

The weather data used in the analysis is from WeatherBank/AccuWeather and the US National Oceanic and Atmospheric Administration ("NOAA") back to 1950. When the geographic size of a service territory is large or does not have a centrally located weather station, MEA uses data from an optimally weighted combination of weather stations to represent the service territory and minimize error in the modelling of demand. The weather stations used for North Carolina East, North Carolina West, and South Carolina, with the optimal weights are shown in *Table 3*.

Table 3 – Weather Stations & Weights

North Carolina East

Weather Station		Weight
Greensboro, NC	KGSO	18.3%
Charlotte, NC	KCLT	29.8%
Pope AFB, NC	KPOB	14.1%
Elizabeth City, NC	KECG	6.4%
Goldsboro, NC	KGWW	9.1%
Wilmington, NC	KILM	22.3%

North Carolina West

Weather Station		Weight
Greensboro, NC	KGSO	52.2%
Charlotte, NC	KCLT	47.8%

South Carolina

Weather Station		Weight
Charlotte, NC	KCLT	8.3%
Greenville, SC	KGSP	91.7%

Heating Degree-Days (HDD)

Temperature, specifically low temperature, represented as Heating Degree Days ("HDD"), is the most basic and primary factor affecting the firm demand for natural gas from natural gas utilities. HDD is a measure of the "need for heating" and is based on the extent to which the daily average temperature falls below a reference temperature (most often, 65°F).

For example, on a day when the average temperature is 35°F, there are 30 HDD. On a day when the average temperature is 65 or higher, there are zero HDD, reflecting that there is no (assumed) need for heating. HDD is expressed by *Equation 1*.

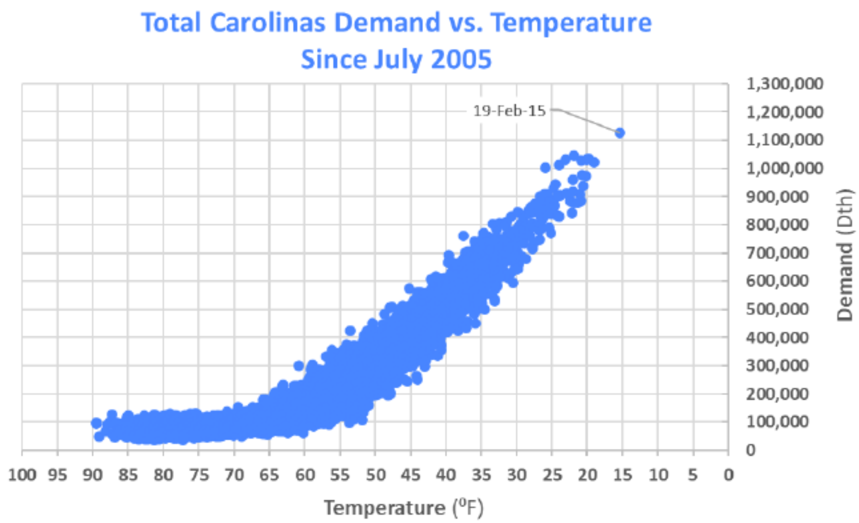
Equation 1 – Heating Degree Days (HDD)

$$HDD = \max(0, T_{ref} - T_k)$$

Where T_k is the average temperature for the kth day and T_{ref} is the reference temperature, generally, 65^{o}F.

Figure 1 is an X-Y plot that shows the historical relationship between the Total Carolinas demand and Temperature for the same gas day, with data from July 2005 to March 2022. There is a clear linear relationship between gas demand and HDD. MEA considers several other factors to improve the modelling of demand, the most important of which being wind and the temperature from the previous day.

Figure 1 – Total Carolinas Demand vs Temp



Inclusion of Wind

Wind is included in the modelling and forecasting of natural gas demand as MEA has found that wind significantly improves the accuracy of demand estimates and forecasts, especially at colder temperatures. Whereas wind creates a "wind chill" felt on exposed skin, buildings lose more heat on a windy day than on a day without wind, leading to a "wind-chill for buildings" effect. Wind-Adjusted Heating Degree Day ("HDDW") approximates this "wind-chill for buildings" effect and is expressed in *Equation 2*, where $Wind$ is wind speed in Miles Per Hour ("MPH"). This methodology for incorporating wind, i.e., *Equation 2* was developed internally by MEA.

Equation 2 – Wind-Adjusted Heating Degree Days (HDDW)

$$HDDW = \begin{cases} HDD \times \dfrac{72 + Wind}{80}, Wind > 8 \\ HDD \times \dfrac{152 + Wind}{160}, Wind \leq 8 \end{cases}$$

Wind-adjusted temperature ("TempW"), T_w, is expressed in *Equation 3*, again, where T_k is the actual average temperature on the kth day and T_{ref} is the reference temperature used to calculate HDD and HDDW.

Equation 3 – Wind-Adjusted Temperature

$$T_w = T_{ref} - HDDW, when\ T_k \leq T_{ref};\ otherwise\ T_k.$$

Table 4 shows combinations of temperature and wind speed that result in wind-adjusted temperature, calculated by applying *Equations 1*, *2* and *3* to temperature and wind. Two different combinations of temperature and wind are shown that result in a wind-adjusted temperature of 6.7°F; the Total Carolinas DDC.

Table 4 – Wind-Adjusted Temperature or "Wind-Chill for Buildings"

Wind-Adjusted Temperature

		Temperature (°F)						
		35	30	25	20	15	10	5
Wind (MPH)	10	34.3	29.1	24.0	18.9	13.8	8.6	3.5
	12.8	33.2	27.9	22.6	17.3	12.0	6.7	1.4
	15	32.4	26.9	21.5	16.1	10.6	5.2	-0.3
	20	30.5	24.8	19.0	13.3	7.5	1.8	-4.0
	21.3	30.0	24.2	18.4	12.5	6.7	0.9	-5.0
	25	28.6	22.6	16.5	10.4	4.4	-1.7	-7.8
	30	26.8	20.4	14.0	7.6	1.3	-5.1	-11.5
	35	24.9	18.2	11.5	4.8	-1.9	-8.6	-15.3
Potential Temp-Wind Combinations for the 1-in-30 DDC, 6.7°F / 58.3 HDDW								

Applying *Equations 1*, *2* and *3* (below) to 10°F and a wind of 12.8 MPH, yields a HDDW of 58.3 and a TempW of 6.7. Applying the equations to 15°F and a wind of 21.3 MPH yields the same TempW and HDDW.

$$HDD = 65 - 10 = 55,$$

$$HDDW = 65 \times \frac{72 + 12.8}{80} = 65 \times 1.06 = \mathbf{58.3},$$

$$T_w = 65 - 58.3 = \mathbf{6.7}$$

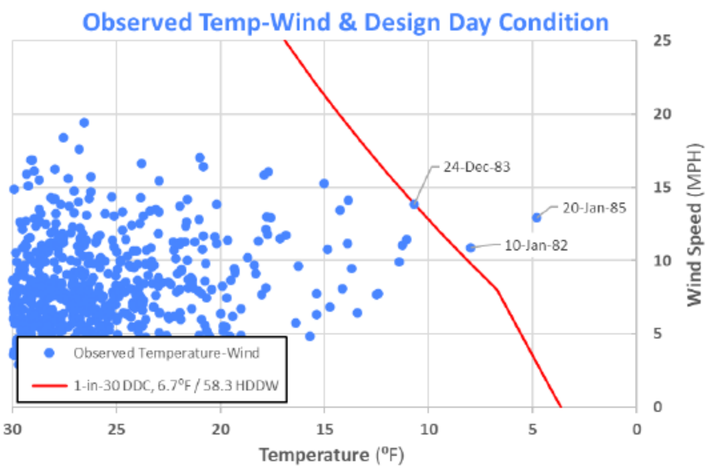
Design Day Conditions

MEA's calculation of the DDC, that is, the TempW and HDDW associated with a 1-in-N-year condition, is based on statistical methods applied to the 121 days of the year with the coldest, wind-adjusted, normal daily average temperature, approximately late-November through late-March, back to 1950.

A 1-in-30-year design day condition ("DDC") is a weather event (HDDW in this case) that you would expect to occur once every 30 years. For a 1-in-30-year event, there is a 3.3% chance of it occurring each year, and an approximately 64% chance of it occurring in a 30-year period. Equivalently, there is a 36% chance of a 1-in-30- year event NOT occurring in a 30-year period. It is also possible for more than one 1-in-30-year event to occur in a 30-year period.

Figure 2 is an X-Y plot that shows historically observed combinations of temperature and wind for the Total Carolinas service territory from 1950 to May 2022 (● in the plot). The red line in the plot represents all combinations of temperature and wind (within the temperature and wind ranges in the figure) that produce the 1-in-30 DDC.

Figure 2 – Total Carolinas Observed Temp-Wind & Design Day Condition



Two days since 1950 have exceeded the 1-in-30-year DDC, Jan. 10, 1982 and Jan. 20 1985, and a third day, Dec. 24, 1985 is the same as the DDC. This is actually close to what should be expected; on average, in a 72-year period, there should be 2.4 (72 / 30 = 2.4) 1-in-30 events.

Applying *Equations 1*, *2* and *3* to the temperature (4.8˚F) and wind (12.9 MPH) observed on Jan. 20, 1985, yields a HDDW of 63.9 and a TempW of 1.1.

$$HDD = 65 - 4.8 = \mathbf{60.2},$$

$$HDDW = 60.2 \times \frac{72 + 12.9}{80} = 60.2 \times 1.06 = \mathbf{63.9},$$

$$T_w = 65 - 63.9 = \mathbf{1.1}$$

Applying *Equations 1*, *2* and *3* to the temperature (10.7˚F) and wind (13.8 MPH) observed on Dec. 24, 1983, yields a HDDW of 58.3 and a TempW of 6.7, the Total Carolinas DDC

Adjusting or “Detrending” Past Load Data

Historical load data is adjusted or “detrended” to make it have the same characteristics as the most recent year of sendout data. Older load data may not be a good indication of the current customer base due to growth in customer base, energy efficiency, changes in customer behavior, changes in customer class composition of load, etc. The purpose of detrending historical load data is to ensure that forecasts based on that data reflect the current customer base characteristics.

Five different linear regression models are used in the detrending process of past load data. In addition to weather variables, the models use different combinations of days of the week and day-of-week and day-of-year cyclical coefficients. The base detrending model is a five-parameter linear regression model with the parameters:

1) ***Constant***,
2) ***HDDW65*** – Wind-Adjusted HDD with a reference temperature of 65⁰F,
3) ***HDDW55*** – Wind-Adjusted HDD with a reference temperature of 55⁰F,
4) ***ΔMHDDW*** – Day-to-Day change in the average of HDDW55 and HDDW65, and
5) ***CDD65*** – CDD (Cooling Degree Day) with a reference temperature of 65⁰F (CDD = $\max(0, T_k - T_{ref})$.

The five different detrending models are:

1) The detrending model on all days,
2) The detrending model on Monday through Thursday,
3) The detrending model with day-of-week coefficients (13-parameter model),
4) The detrending model with day-of-year coefficients (13-parameter model), and
5) The detrending model with day-of-week and day-of-year coefficients (21-parameter model).

To detrend the historical load data, the five regression models are fit to windows of historical data. Each window contains one year of data and is offset one month from the previous window. From the change in estimated parameter coefficients through time (month-to-month), the temporal change in several demand characteristics is determined: primarily, baseload and heatload (use per HDD) demand. Older data is adjusted by the change in the regression parameter coefficients to detrend the data and make it “look like” current data.

Final Design Day Load Forecast

The process for forecasting the design day load is 1) estimate a design day for the last heating season, 2) use historical trends in baseload and heatload to project design day demand for the next heating season, and 3) forecast design day demand out over future heating seasons.

Estimate Design Day Demand for the Last Heating Season – Winter 2021-22

Each of the five component detrending models above is fit to the detrended data and evaluated at the DDC. Additionally, using detrended data, a line fit through a scatterplot of the 20% coldest days, and through the 20% coldest Mondays through Thursdays of Model #1 and through the coldest Mondays through Thursdays of Model #2 is evaluated at the DDC to provide three additional design day estimates, for a total of 8 estimates of the past heating season, in this case winter 2021-22. Combining forecasts derived from different methods, often called "ensemble forecasting", has been shown to be more accurate and is a well-accepted practice in the forecasting field. The models are weighted according to their statistical confidence.

Table 5 – Total Carolinas Design Day Estimates - Winter 2021-22

Design Day Estimates (Dth) - Winter 2021-2022

Design Day Model	North Carolina East	North Carolina West	South Carolina	Total Carolinas
Model 1	298,400	886,133	226,714	1,411,247
- Line fit 20% Coldest Days	312,000	908,910	235,685	1,456,595
- Line fit 20% Coldest Mon-Thur	308,809	905,615	239,022	1,453,445
Model 2	301,091	894,741	228,542	1,424,373
- Line fit 20% Coldest Days	303,744	904,055	236,545	1,444,344
Model 3	293,005	846,761	218,896	1,358,662
Model 4	299,710	889,458	228,224	1,417,392
Model 5	296,839	858,366	223,567	1,378,772
Weighted Average Estimate	**301,456**	**889,144**	**229,418**	**1,420,018**

Forecast Design Day Demand to the Next Heating Season – Winter 2022-23

Trends in baseload and heatload are determined for the five detrending models and evaluated at the DDC, then applied to the prior winter Design Day Estimate to produce a Design Day Forecast for the next winter. Assumptions about customer growth are also incorporated.

Additionally, the design day forecast is adjusted upwards by 2.5 forecast standard deviations to produce another forecast with an approximately 99% confidence level, the *99% Confidence Forecast*, meaning, if a 1-in-30 weather event occurs, there is an 99% probability that actual demand will not exceed the 99% Confidence Forecast, or alternatively, only a 1% chance that the forecast will be exceeded.

MEA adds a Winter Severity Adjustment when forecasting design demand in warmer climates. MEA has found that in warmer regions, demand per HDDW is larger during colder than average winters relative to warmer winters. In colder climates, demand per HDDW tends to be constant regardless of the severity of the winter.

Table 6 – Total Carolinas Design Day Forecasts - Winter 2022-23

Design Day Forecasts (Dth) - Winter 2022-2023

Design Day Forecast	North Carolina East	North Carolina West	South Carolina	Total Carolinas
Estimate for Winter 2020-21	301,456	889,144	229,418	1,420,018
- Winter Severity Adjustment	1,794	1,684	1,054	4,532
- Baseload Growth	-1,000	-1,000	-625	-2,625
- Heatload Growth	0	-897	0	-897
- Customer Growth Adjustment	4,808	14,142	4,915	23,865
Design Day Forecast	**307,058**	**903,072**	**234,763**	**1,444,893**
2.5 Forecast Standard Deviations	38,171	42,595	11,082	67,133 *
99% Confidence Forecast	**345,229**	**945,667**	**245,845**	**1,512,026**

* Total forecast standard deviations and 99% confidence forecasts are not additive across service territories.

Five-Year Design Day Demand Growth Forecast

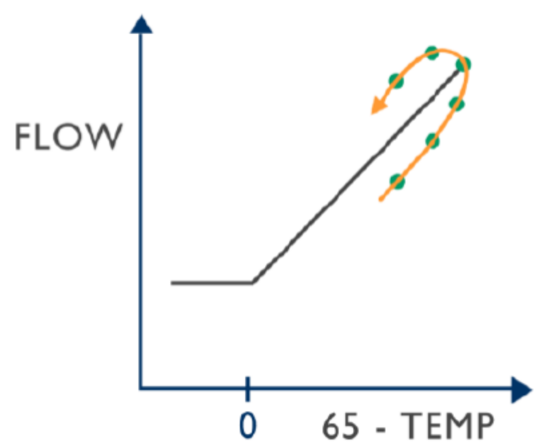
MEA forecasts design day growth out five years using a different methodology, including directly incorporating assumptions about customer growth. A long-term forecasting model is used to forecast changes in baseload and heatload out one to five years. This is accomplished with an ensemble of models that fit the historical data with linear and exponential trends of both the baseload and heatload demand.

Appendix A – Other Factors Affecting Demand

The Heck-with-it-Hook

An upturn in usage is often observed during long extreme cold weather events. On a sequence of colder days, people tend to tolerate the first few days, but then decide, "I'm cold, I'm turning up the thermostat, I don't care what it costs, the heck with it."

The sample scatter plot figure below illustrates this effect. It shows how higher-demand days that occur later in a cold stretch tend to 'hook' over lower-demand earlier days. Two days with the same weather conditions might have significantly different demand, depending on where they fall within the sequence of days in the cold event.



One possible result of the "heck-with-it-hook" phenomenon is that the highest demand may not occur on the coldest day.

Previous Day Effects

While the most important factor in estimating today's demand is today's HDDW, the second most important factor is yesterday's HDDW, or the change in HDDW from the prior day (ΔHDDW). The regression coefficient for ΔHDDW is typically negative, meaning on days with the prior day warmer than the current day (ΔHDDW > 0), there is typically a negative effect on demand (less demand that if the prior day's HDDW were the same, i.e., ΔHDDW = 0), and on days with the prior day colder than the current day, there is typically a positive effect. This is likely due to thermodynamics of heating buildings, and possibly some behavioral heck-with-it-hook effect.

Day-of-Week and Day-of-Year Effects

Another significant factor affecting demand can be the day-of-week ("DoW") or day-of-year ("DoY") on which the demand occurs. For example, on weekends residential demand increases, but this demand tends to be offset by decreases in commercial and residential demand; the total effect on demand being determined by the residential, commercial, and industrial composition of demand. Periodic factors such as day-of-week and day-of-year can be represented by Fourier series. The days of the year are periodic, with a period of 365 days. A DoY factor can be used to represent this 365-day frequency:

$$sin\left(\frac{2\pi DoY}{365}\right), \quad cos\left(\frac{2\pi DoY}{365}\right).$$

Holidays and days around holidays can also have an effect on demand like that of weekends. There can also be a Friday effect. Given the industry definition of a gas day is 9am to 9am (for much of Piedmont's territory), a Friday includes Saturday morning, and it is often observed that Friday demand is lower than the other weekdays, yet higher than Saturday and Sunday demands. Similarly for Sunday gas day, which includes Monday morning.

There are countless different factors and combinations of factors that affect the demand for natural gas, and these vary by gas utility, climate, season, and geographic region. When conduction a design day study and forecast, MEA makes every attempt to include, given practicality and data availability, all statistically significant and meaningful variables.

Marquette
Energy
Analytics

Piedmont
Natural Gas

Piedmont Natural Gas

Design Day Study & Forecast

July 28, 2022

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Milwaukee, WI 53202

Marquette Energy Analytics

Natural Gas Industry Experience

Marquette Energy Analytics ("MEA") specializes in energy demand modelling, forecasting and analytics, and for over twenty-five years has provided services to more than forty gas distribution companies accounting for over 20% of gas consumption in the United States.

Design Day Forecasting

MEA forecasts natural gas demand for peak or "design" day under extreme weather conditions.

- ✓ Single and Multiple Service Territories
- ✓ Customer-Class Studies
- ✓ Sales and Transport Load

Natural Gas Demand Forecasting

MEA's Flagship product, MCast GasDay, delivers real-time daily and hourly natural gas demand forecasts.

- ✓ 25 Years of Experience
- ✓ 20% of United States Gas Consumption
- ✓ Forecasts Cover Over 20 Million Customers

Regulatory Support

MEA supports our analysis and forecasts in State regulatory proceedings, including expert testimony.

- ✓ Gas Cost Adjustment (GCA) filings
- ✓ Capacity Adequacy Proceedings
- ✓ Regulatory Investigations & Workshops

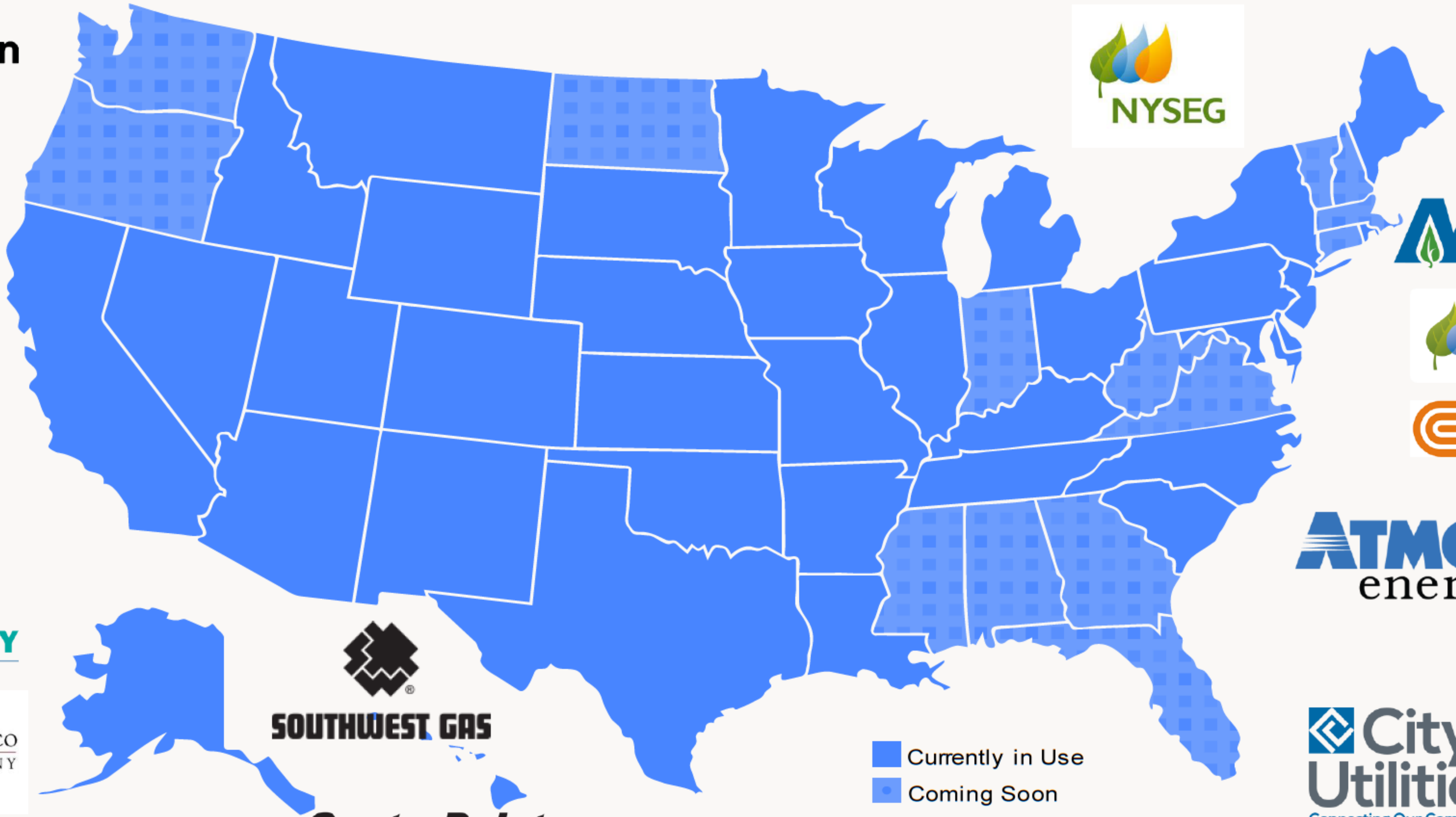
Custom Analytics & Consulting Services

MEA expands on our core forecasting services to address customers specific needs and forecasting requirements, e.g.,

- ✓ Evaluation of Energy Efficiency Programs
- ✓ Design Day by Zip-Code or Neighborhood

Marquette Energy Analytics

National Presence



Washington Gas A WGL Company

DUKE ENERGY

ONE Gas

SoCalGas

SEMCO ENERGY GAS COMPANY

PG&E

New Mexico GAS COMPANY

MEC MIDWEST ENERGY & COMMUNICATIONS

ENSTAR Natural Gas Company

SOUTHWEST GAS

CenterPoint Energy

HEARTHSTONE UTILITIES, INC.

UGI

NYSEG

AltaGas

Black Hills Corporation Ready

AmeriGas

Dominion Energy

New Jersey Natural Gas

People. Power. Possibilities. Central Hudson A FORTIS COMPANY

AVANGRID

Orange & Rockland

nationalgrid

ATMOS energy

conEdison

City Utilities Connecting Our Community

Piedmont Natural Gas

delmarva power

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Marquette Energy Analytics

MEA Experts

Dr. Ronald Brown is the Chief Science Officer and founder of MEA and leads the development of all products and analysis. Dr. Brown founded Marquette University's GasDay Laboratory in 1993 to undertake research into energy demand forecasting. In late 2018 Dr. Brown worked with Marquette University to establish Marquette Energy Analytics as a private company focused on growing the portfolio of energy demand forecasting tools and consulting services.

Greg Merkel is the Lead Data Scientist at MEA. In this role Greg leads the Data Science team, which monitors and improves the performance of MEA's hundreds of live models producing thousands of energy demand forecasts a day. Greg also supervises the infrastructure that supports all the data and analytics engines maintained by MEA.

Public Staff Design Day Methodology Issues

MEA recognizes that the NCUC Public Staff requested that Piedmont address five issues with Piedmont's Design Day methodology. MEA's Design Day Study & Forecast address all the issues.

1. Appropriate Allocation of Lost and Unaccounted For (LAUF) Gas to Firm Sales (FS) customers,
   - ✓ The load data used in the analysis appropriately allocates FS customers only their share of LAUF.
2. Timing Inconsistencies between Temperature (and Wind) data and Metered Demand Data,
   - ✓ MEA uses hourly temperature and wind data to construct Wind-Adjusted Temperature ("TempW") and Wind Adjusted HDD ("HDDW") consistent with the NAESB Gas Day (10am – 10am Eastern Time) and metered gas load.
3. Appropriately Adjust Past Data for Customer Growth to Reflect Current Demand,
   - ✓ Past data its detrended to account for customer growth and changes in baseload and heatload (use per HDD) demand. This is a major component of MEA's design day analysis.
4. Evaluation of Linear versus Non-Linear Regression and Explaining Extreme Occurrences,
   - ✓ MEA has found linear modelling appropriate (with wind and prior-day parameters) but some non-linear concerns are addressed.
5. Addressing Weekend Demand and Accounting for the Low Usage on Weekends.
   - ✓ MEA's uses an "ensemble" modelling approach where some models only use Monday – Thursday data, and Day-of-Week cyclical variables are included in other models.

Marquette Energy Analytics

Design Day Forecast & Design Day Conditions

Piedmont Natural Gas Company, Inc. retained MEA to perform a Design Day Demand Study. The purpose of a design day study and forecast is to determine the quantity of natural gas expected to be used during an extreme cold winter day, a "Design Day".

Piedmont Design Day Forecast

Design Day Forecast (Dth)	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
North Carolina East	307,058	308,325	310,925	313,317	316,035
North Carolina West	903,072	923,178	944,543	965,262	986,489
South Carolina	234,763	239,835	245,396	250,852	256,391
Total Carolinas	**1,444,893**	**1,471,338**	**1,500,864**	**1,529,431**	**1,558,914**
99% Confidence Forecast	**1,512,026**	**1,538,471**	**1,567,997**	**1,596,564**	**1,626,047**

1-in-30 Year Design Day Conditions

Service Territory	TempW	HDDW
North Carolina East	9.5	55.5
North Carolina West	5.2	59.8
South Carolina	8.6	56.4
Total Carolinas (wgt. avg.)	**6.7**	**58.3**

Wind-Adjusted Temperature and HDD

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Piedmont Design Day Forecast vs. MEA Forecast

Total Firm Sales Demand Comparison

(All Values in Dt/d)

2022-2023 DEMAND	**Previous Methodology**	**Updated Methodology**	**Variance**	**%**
System Design Day Firm Sendout	**1,349,408**	**1,444,893**	**95,485**	**7.08%**
Mid Year Firm Sales Pick Up	1,379	1,379	0	0.00%
Mid Year Firm Sales Deduct (move to Firm Transport)	(3,776)	(3,776)	0	0.00%
Subtotal Sendout plus Mid Year Pickup	**1,347,011**	**1,442,497**	**95,485**	**7.09%**
Special Contract Firm Sales Commitment	7,233	7,233	0	0.00%
Total Firm Design Day Demand	**1,354,244**	**1,449,730**	**95,485**	**7.05%**
Reserve Margin on Design Day Demand (5%)	**67,712**	**72,486**	**4,774**	**7.05%**
Total Firm Sales Demand	**1,421,957**	**1,522,216**	**100,260**	**7.05%**

Note: Updated Methodology utilizes Marquette Energy Analytics forecast for 2022-2023 system design day firm sendout

Previous Design Day Condition (Jan. 21, 1985): **8.69°F / 56.31 HDD**

Updated MEA Design Day Condition: **Wind-Adjusted 6.7°F / 58.3 HDDW**

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Design Day Demand Methodology

Design day demand estimates and forecasts are based on relationships between natural gas demand and factors including temperature, wind, prior-day temperature and wind, day-of-week and day-of-year variables.

MEA Design Day Forecast Methodology

- Collect and Validate Data for Analysis
- Calculate Wind-Adjusted Temperature and HDD
- Optimize Weather Station Data for Specific LDC Service Territory(s)
- Determine Design Day Conditions (“DDC”)
- Detrend Historical Demand Data
- Forecast Design Day Demand
- Calculate a 99% Confidence Forecast
- Extend Forecast Five to Ten Years

Marquette Energy Analytics

Wind-Adjusted Temperature – Total Carolinas

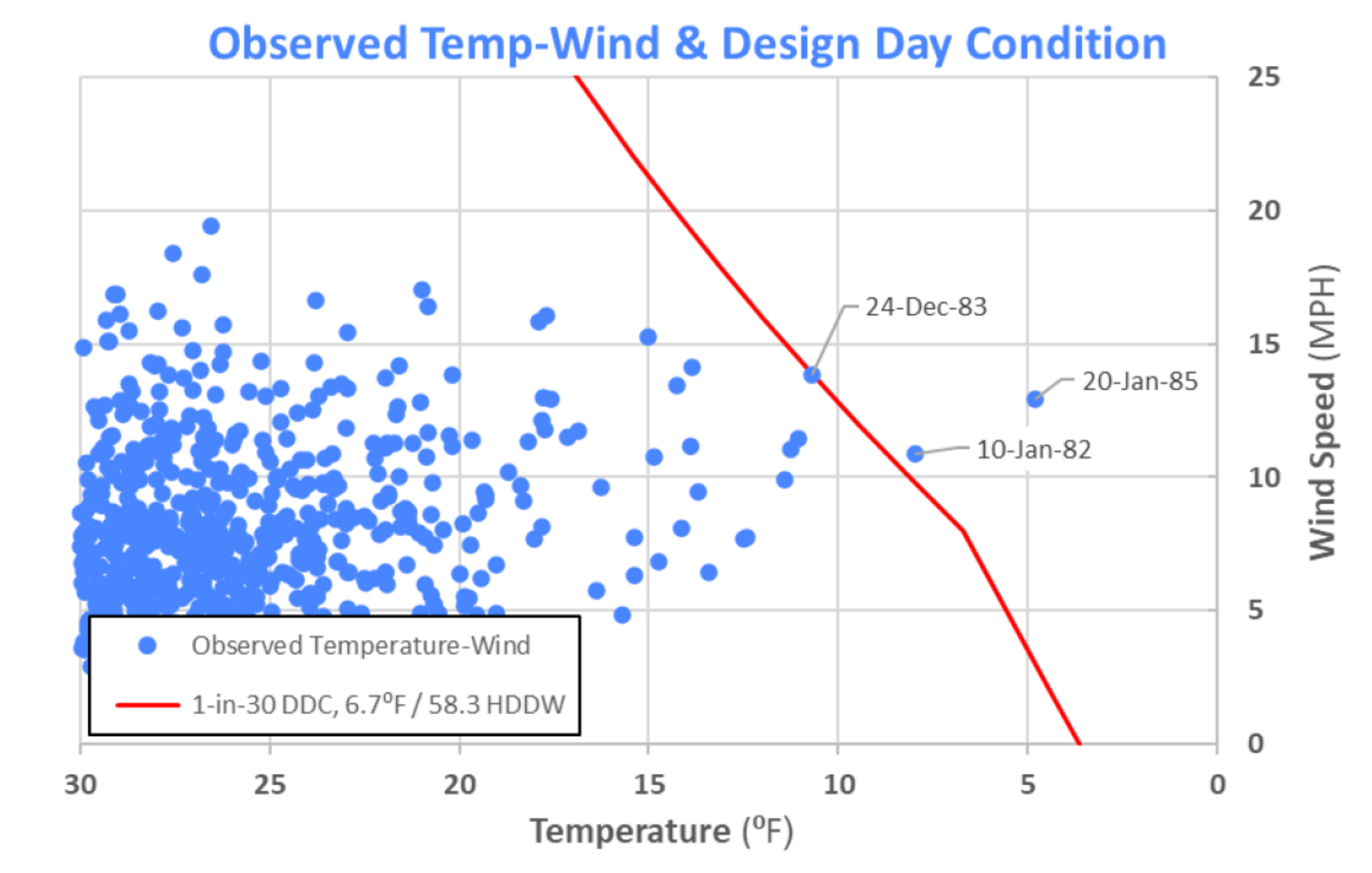
MEA has found that the inclusion of wind significantly improves estimates and forecasts of Design Day Demand. The effect of wind is included through an adjustment of HDD. Design conditions are stated as wind adjusted temperature or wind-adjusted HDD (HDDW).

$$HDDW = \begin{cases} HDD\dfrac{72 + Wind}{80}, Wind > 8 \\ HDD\dfrac{152 + Wind}{160}, Wind \le 8 \end{cases}$$

Wind-Adjusted Temperature

Wind (MPH)	Temperature (°F) 35	30	25	20	15	10	5
10	34.3	29.1	24.0	18.9	13.8	8.6	3.5
12.8	33.2	27.9	22.6	17.3	12.0	6.7	1.4
15	32.4	26.9	21.5	16.1	10.6	5.2	-0.3
20	30.5	24.8	19.0	13.3	7.5	1.8	-4.0
21.3	30.0	24.2	18.4	12.5	6.7	0.9	-5.0
25	28.6	22.6	16.5	10.4	4.4	-1.7	-7.8
30	26.8	20.4	14.0	7.6	1.3	-5.1	-11.5
35	24.9	18.2	11.5	4.8	-1.9	-8.6	-15.3

Potential Temp-Wind Combinations for the 1-in-30 DDC, 6.7°F / 58.3 HDDW



Any Temp-Wind combination along the red line, or 6.7°F / 58.3 HDDW locus, equates to the DDC.

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Weather Station Optimization

MEA uses data from an optimally weighted combination of weather stations to represent the service territory and minimize error in the modelling of demand.

North Carolina East

Weather Station		Weight
Greensboro, NC	KGSO	18.3%
Charlotte, NC	KCLT	29.8%
Pope AFB, NC	KPOB	14.1%
Elizabeth City, NC	KECG	6.4%
Goldsboro, NC	KGWW	9.1%
Wilmington, NC	KILM	22.3%

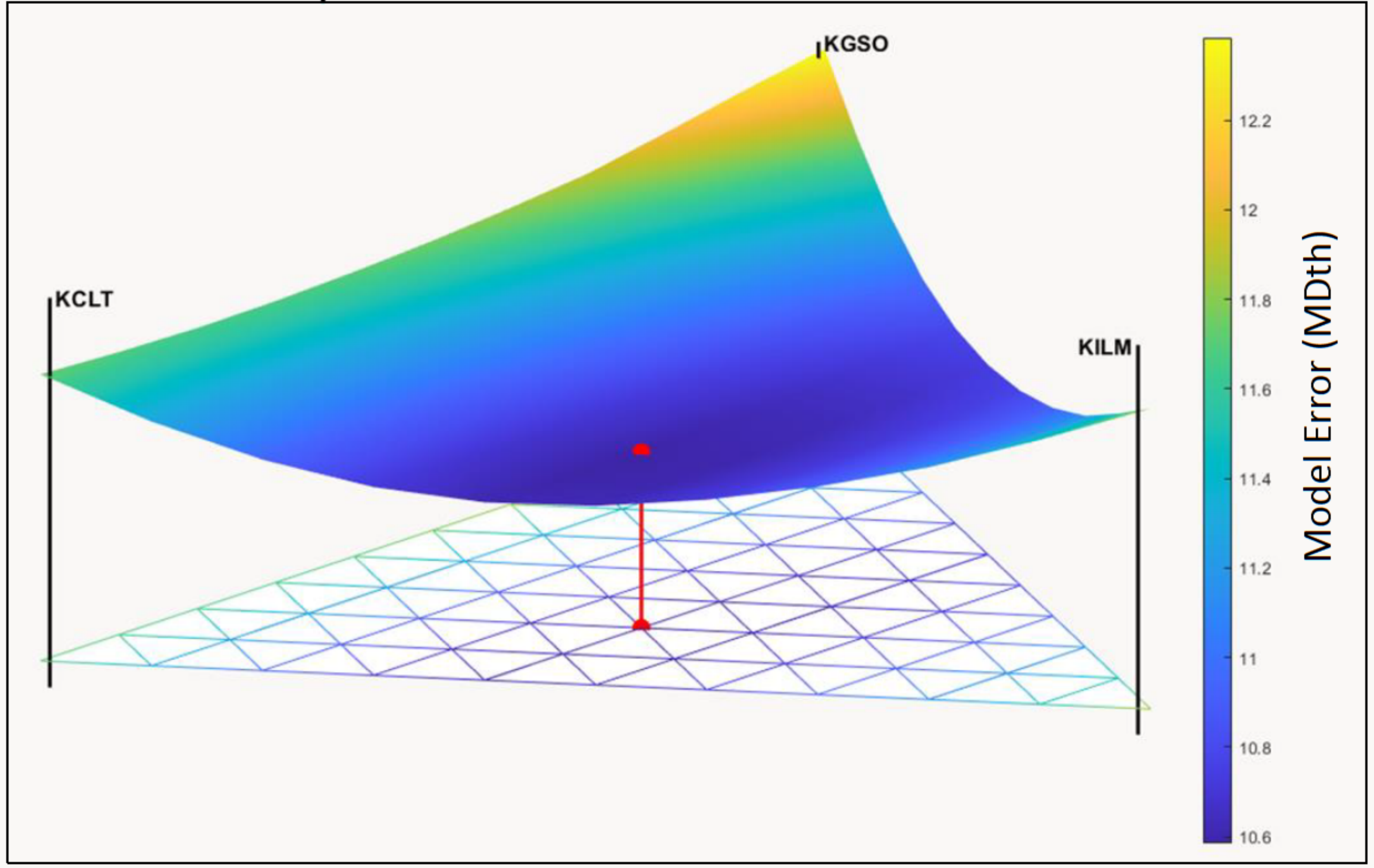
North Carolina West

Weather Station		Weight
Greensboro, NC	KGSO	52.2%
Charlotte, NC	KCLT	47.8%

South Carolina

Weather Station		Weight
Charlotte, NC	KCLT	8.3%
Greenville, SC	KGSP	91.7%

NC East Example with 3 Weather Stations



Previous Design Day Condition

The previous design day condition of 8.69°F / HDD 56.31 was based on the average of calendar day high and low temperatures for various weighted weather stations on January 21, 1985.

DESIGN DAY WINTER 21-22

Calculated Weighted Average Temperature - 1/21/1985 - Carolinas

With 2021 Weights Across Weather Stations

High Temp	Low Temp	Avg Temp **	Weather Station	Weighting *	Weighted Avg
1	-12	-5.5	GEV	0.00514303	-0.0282866
21	-8	6.5	GSO	0.28427454	1.84778452
24	-5	9.5	CLT	0.32105776	3.05004869
23	-8	7.5	HKY	0.05605177	0.42038831
26	-4	11	GSP	0.16999264	1.86991904
16	-2	7	ECG	0.00871322	0.06099256
18	-1	8.5	POB	0.05343834	0.45422593
18	-1	8.5	GWW	0.08028799	0.6824479
27	5	16	ILM	0.02104071	0.3366513
			Weighted Average Temperature		**8.69**
					56.31

* Using calculated weightings based on data from 4/1/20 to 3/31/21

** Average of high and low temperatures

Differences due to Averaging and Wind-Adjustment:

Charlotte (CLT)

	January 21, 1985	January 20, 1985
Temperature		
Calender Day High	24.0	41.0
Calender Day Low	-5.0	-1.0
Average	**9.5**	20.0
Gas Day Hourly Avgerage	15.0	5.2
Wind-Adjusted Temperature		
Gas Day Hourly Average	14.3	1.4

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MEA Design Day Conditions

Although LDCs use a variety of DDC in Developing Design Days Forecasts, many use a "1-in-N-Year" DDC representing a weather condition expected to occur once every 'N' Years.

MEA uses a Proprietary Methodology to Determine a 1-in-N Year Condition

- Statistically Sound and Defensible
- Validated in multiple geographic areas and climates across the Unites States
- Supports the validity of the Design Day Estimate and Forecast
- Although MEA recommends the 1-in-N DDC methodology, other DDC can be used as the basis of a Design Day Forecast.

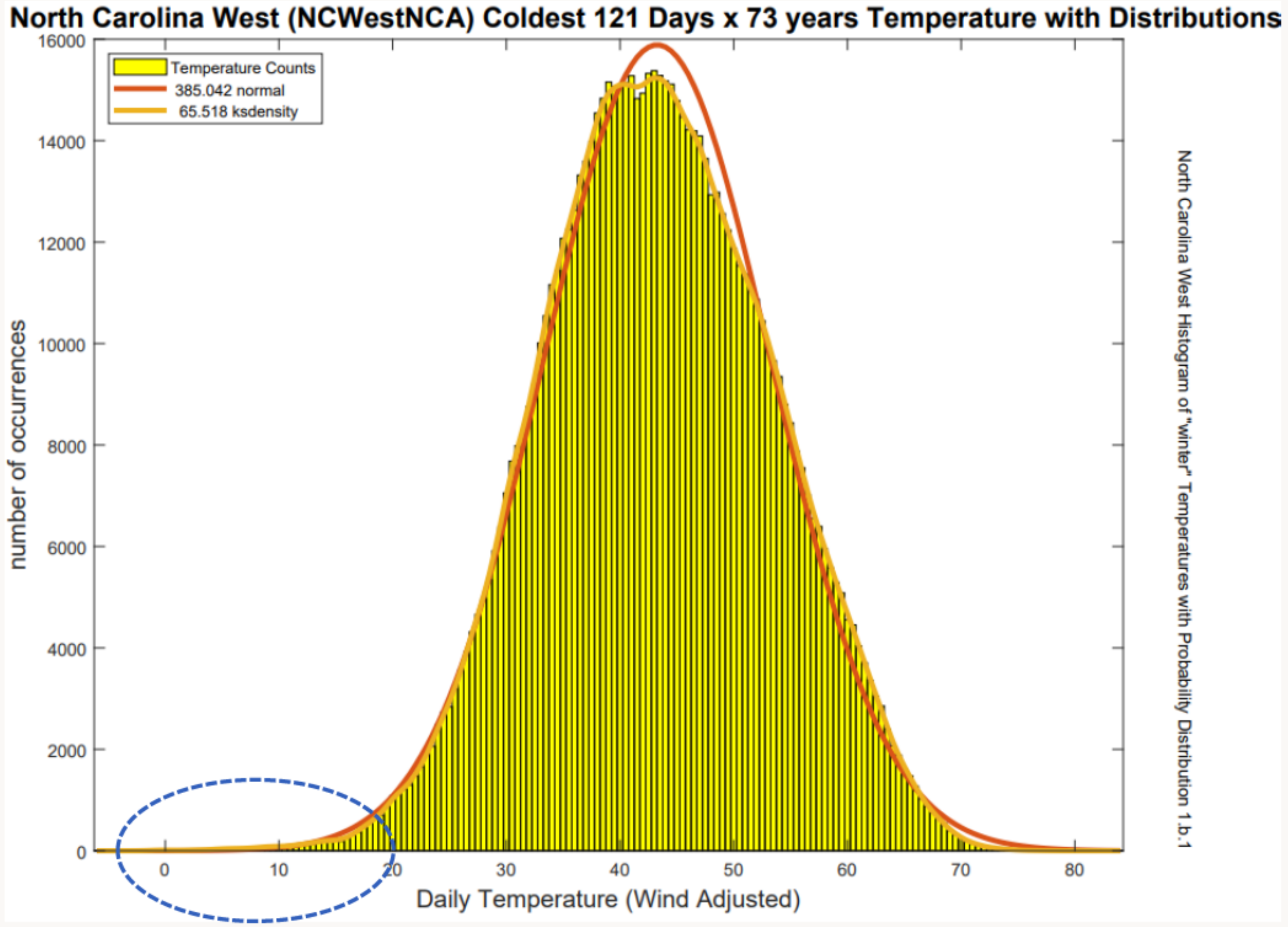
From AGA Survey of LDCs DDC Methodology

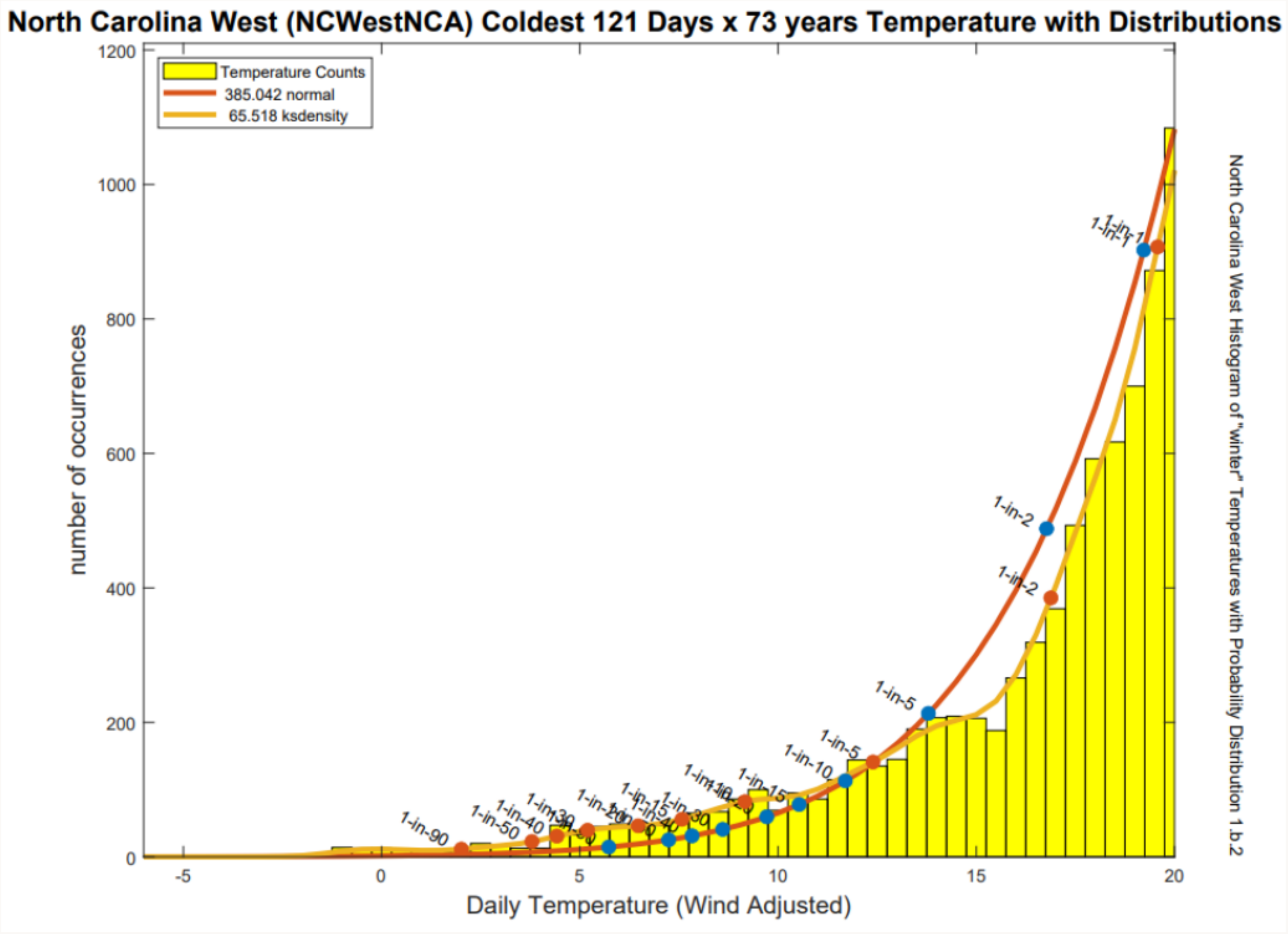
Design Day Condition*	# and % of LDCs
1-in-50 Years	3 (4%)
1-in-30	24 (36%)
1-in-20	4 (6%)
1-in-15	2 (3%)
1-in-10	4 (6%)
Other : '…from 20 years to 1-in-90 years …"	14 (21%)
Other : Hist. Peak, specific day/event, regression, etc.	16 (24%)

* AGA Report, 'LDC Supply Portfolio Management During the 2018-2019 Winter Heating Season," Dec. 20, 2019

"1-in-N Year" Design Weather Methodology *

MEA's 1-in-N year design weather methodology provides a statistically sound and defensible methodology for the determination of design day conditions.





* Kaftan, D.; Corliss, G.F.; Povinelli, R.J.; Brown, R.H. *A Surrogate Weather Generator for Estimating Natural Gas Design Day Conditions*. Energies 2021, 14, 7118. https://doi.org/10.3390/en14217118

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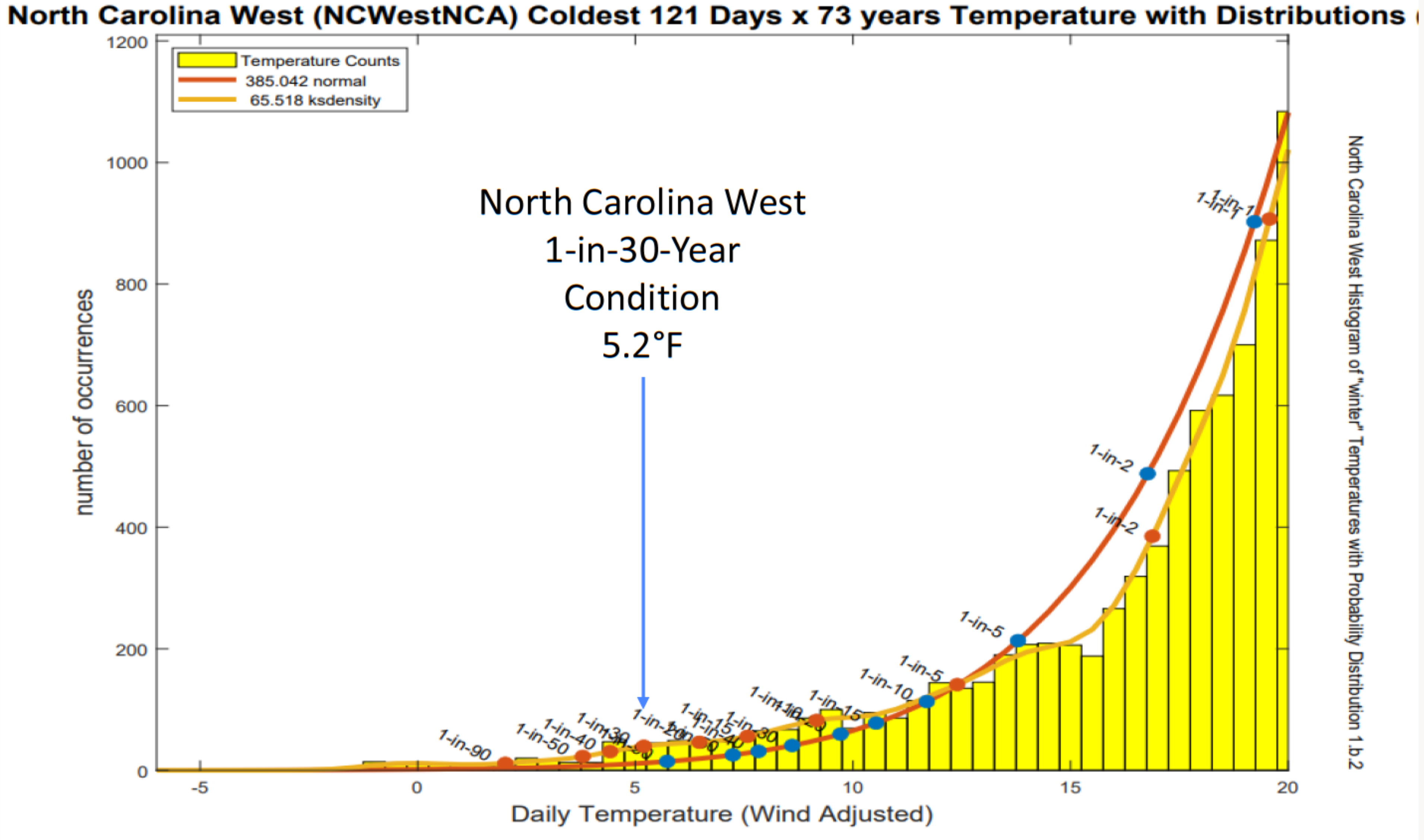
MEA's 1-in-N year design weather methodology provides a statistically sound and defensible methodology for the determination of design day conditions.



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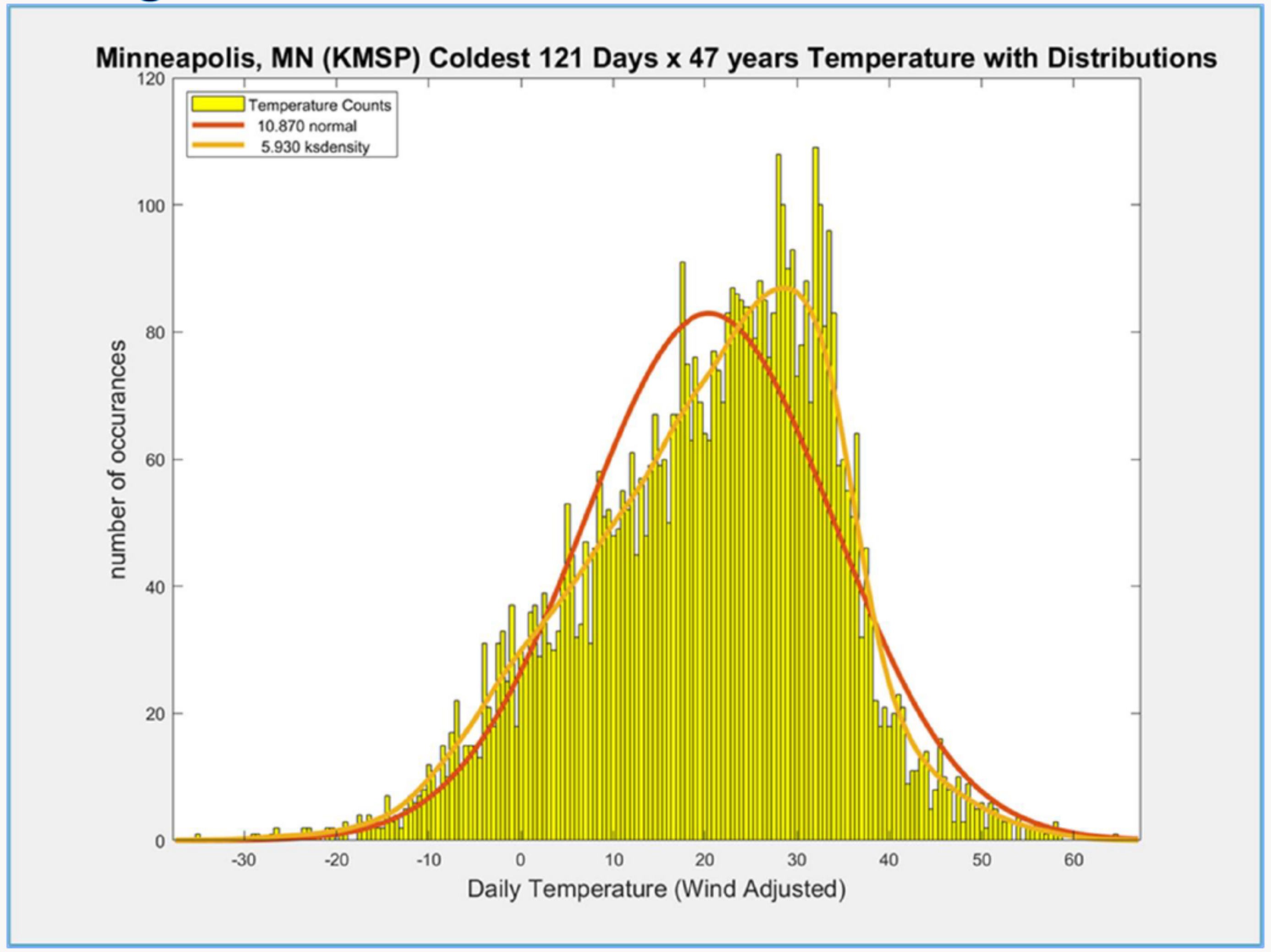
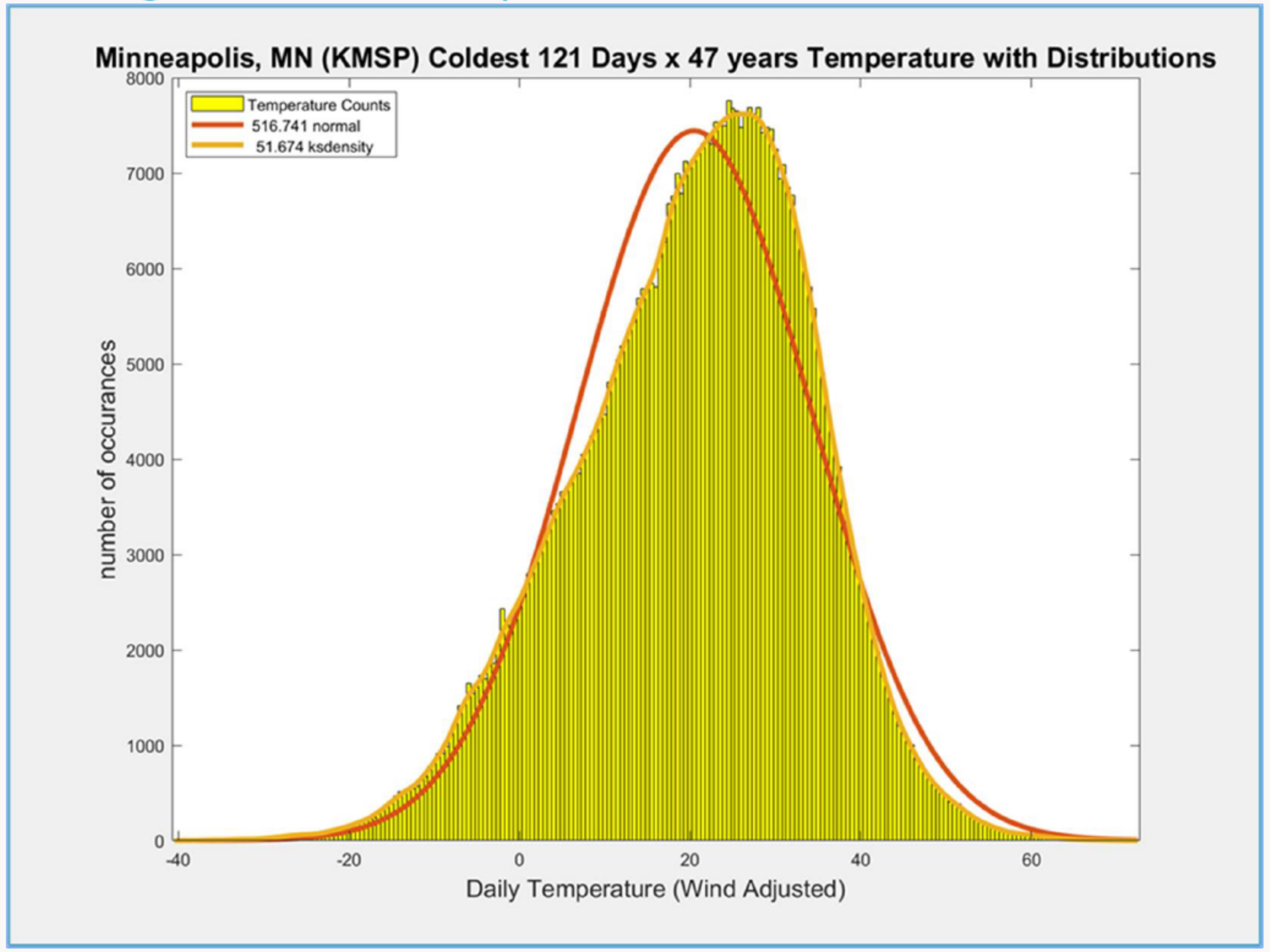
Digression: Surrogate Weather Generator *

MEA's Surrogate Weather Generation uses characteristics of actual historical data to generate additional plausible weather data to calculate extreme 1-in-N values.

Histogram – Historical Weather Data



Histogram – "Resampled" Weather Data



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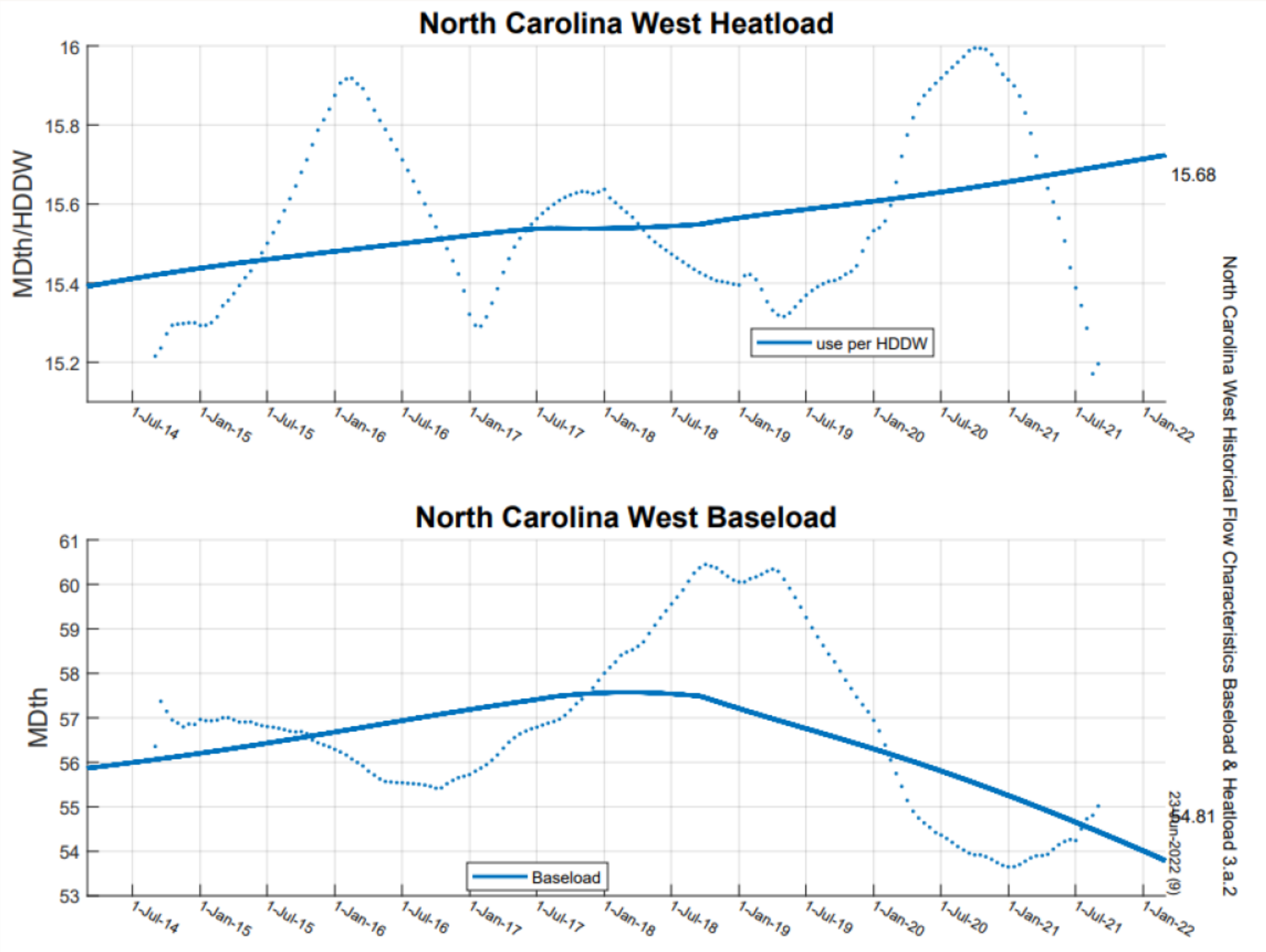
Marquette Energy Analytics

Modelling & Detrending Past Data

Historical sendout data is adjusted or “detrended” to make it have the same characteristics as the most recent year of sendout data. This detrending process adjusts or normalizes past data to account for customer growth (or decrease) and changes in baseload and heatload (use per HDDW) demand per Customer.



In Piedmont’s Updated Design Day Analysis:

- MEA first calculated historical per-customer load from past load and number of customers,
- Then detrended the resulting per-customer load to account for historical changes in per-customer baseload and heatload demand.

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Modelling & Detrending Past Data

Five different linear regression models are used in the detrending process of past load data. In addition to weather variables, the models use different combinations of days of the week and day-of-week and day-of-year cyclical coefficients.

The base detrending model is a five-parameter linear regression model with the parameters:

1) Constant,
2) HDDW65 – Wind-Adjusted HDD with a reference temperature of 65^{o}F,
3) HDDW55 – Wind-Adjusted HDD with a reference temperature of 55^{o}F,
4) ΔMHDDW – Day-to-Day change in the average of HDDW55 and HDDW65, and
5) CDD65 – Cooling Degree Day with a reference temperature of 65^{o}F.

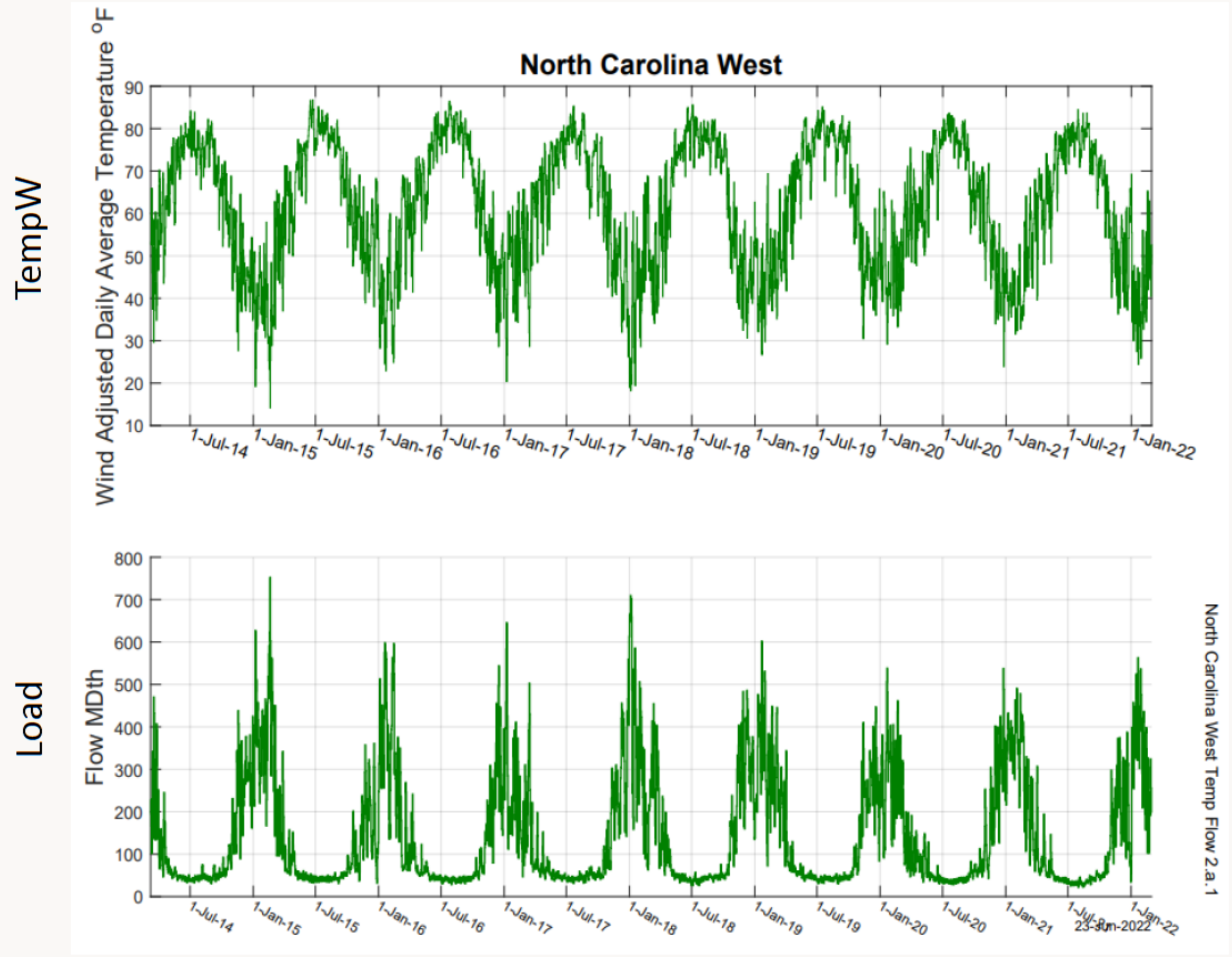
The five detrending models are:

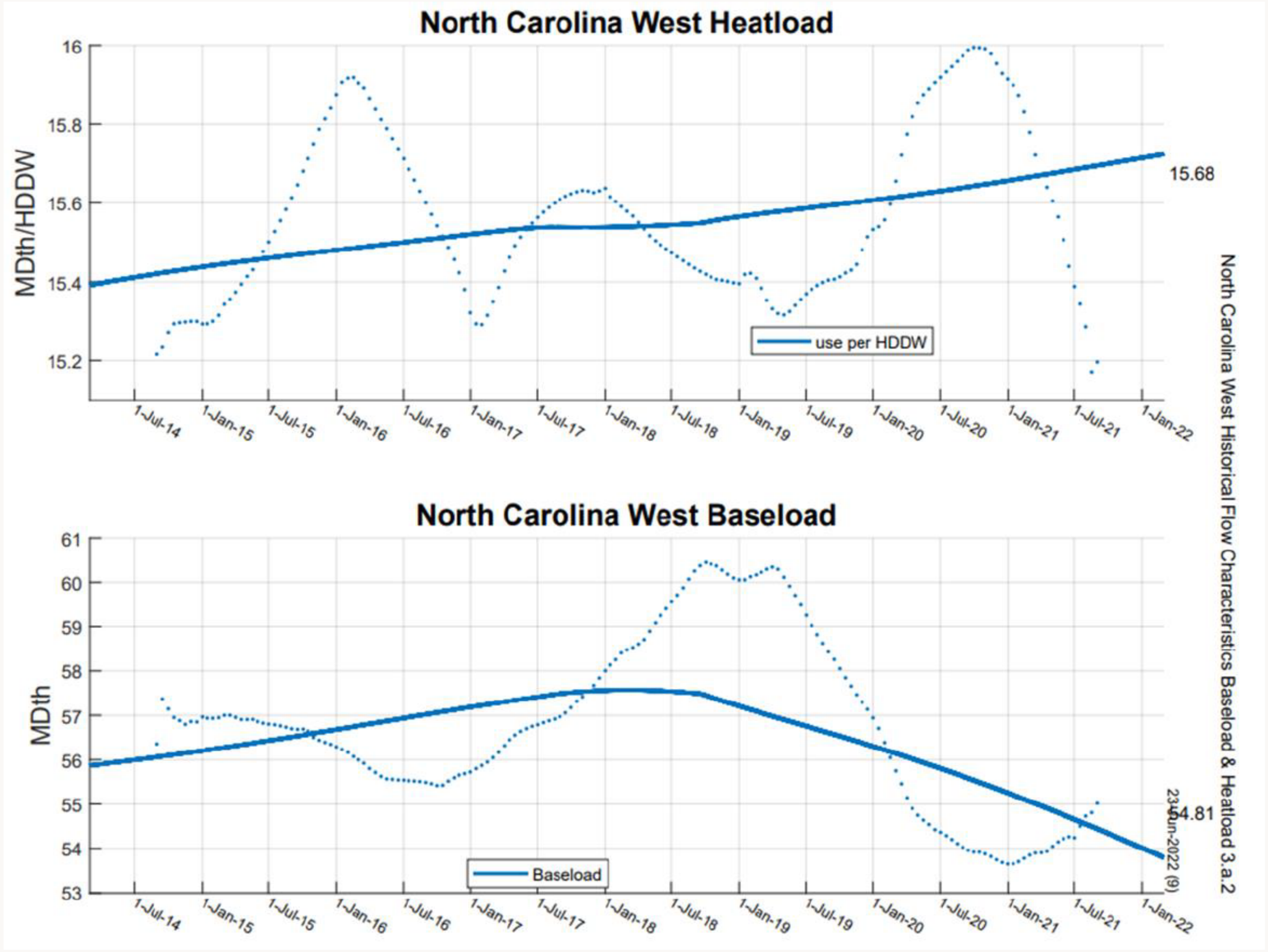
1) The base detrending model on all days,
2) The base detrending model on Monday through Thursday,
3) The base detrending model with day-of-week coefficients (13-parameter model),
4) The base detrending with day-of-year coefficients (13-parameter model) and
5) The base detrending with day-of-week and day-of-year coefficients (21-parameter model).

Marquette Energy Analytics

Modelling & Detrending Past Data

Historical sendout data is adjusted or “detrended” to make it have the same characteristics as the most recent year of sendout data. Trends in baseload and heatload (demand per HDD) are determined.





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Marquette Energy Analytics

Estimating Design Day for The Prior Year

Each of the five component detrending models above is fit to the detrended data and evaluated at the DDC.

1) The base detrending model on all days,
2) The base detrending model on Monday through Thursday ,
3) The base detrending model with day-of-week coefficients (13-parameter model),
4) The base detrending with day-of-year coefficients (13-parameter model) and
5) The base detrending with day-of-week and day-of-year coefficients (21-parameter model).

An additional three models are evaluated at the DDC and used in forecasting design day demand:

1) With Model #1
   - ✓ A line fit through the 20% coldest days, and
   - ✓ A line fit through the 20% coldest Mondays through Thursdays.
2) With Model #2
   - ✓ A line fit through the 20% coldest days.

Marquette Energy Analytics

Estimating Design Day for the Prior Year

Design Day Estimates (Dth) - Winter 2021-2022

Design Day Model	North Carolina East	North Carolina West	South Carolina	Total Carolinas
Model 1	298,400	886,133	226,714	1,411,247
- Line fit 20% Coldest Days	312,000	908,910	235,685	1,456,595
- Line fit 20% Coldest Mon-Thur	308,809	905,615	239,022	1,453,445
Model 2	301,091	894,741	228,542	1,424,373
- Line fit 20% Coldest Days	303,744	904,055	236,545	1,444,344
Model 3	293,005	846,761	218,896	1,358,662
Model 4	299,710	889,458	228,224	1,417,392
Model 5	296,839	858,366	223,567	1,378,772
Weighted Average Estimate	**301,456**	**889,144**	**229,418**	**1,420,018**

Ensemble Modelling & Forecasting – Combining forecasts derived from different methods, often called "ensemble forecasting", has been shown to be more accurate and is a well-accepted practice in the forecasting field. The models are weighted according to their statistical confidence.

Marquette Energy Analytics

Forecasting Design Day for the Next Year

Design Day Forecasts (Dth) - Winter 2022-2023

Design Day Forecast	North Carolina East	North Carolina West	South Carolina	Total Carolinas
Estimate for Winter 2020-21	301,456	889,144	229,418	1,420,018
- Winter Severity Adjustment	1,794	1,684	1,054	4,532
- Baseload Growth	-1,000	-1,000	-625	-2,625
- Heatload Growth	0	-897	0	-897
- Customer Growth Adjustment	4,808	14,142	4,915	23,865
Design Day Forecast	**307,058**	**903,072**	**234,763**	**1,444,893**
2.5 Forecast Standard Deviations	38,171	42,595	11,082	67,133
99% Confidence Forecast	**345,229**	**945,667**	**245,845**	**1,512,026**

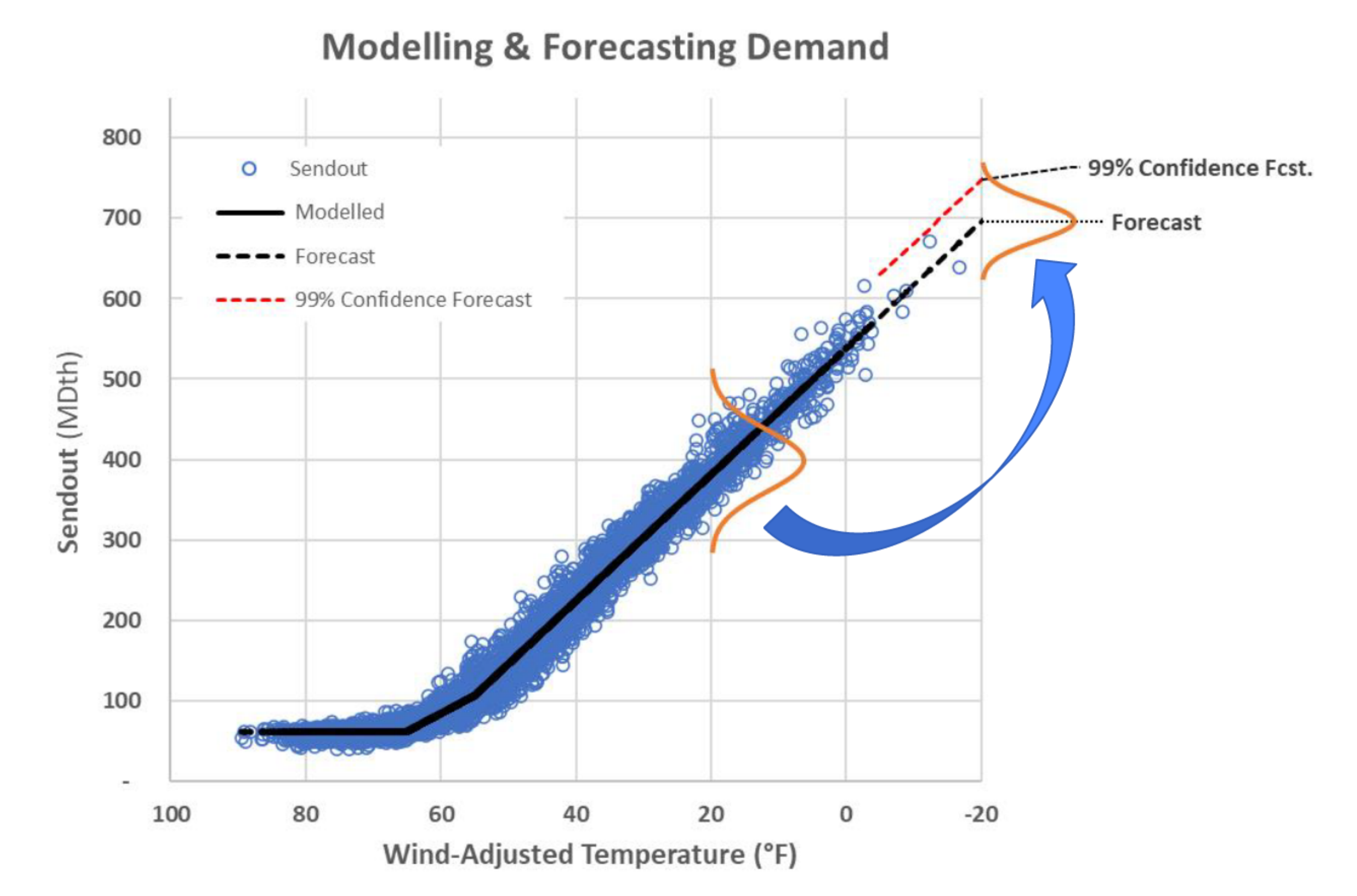
Winter Severity Adjustment – MEA has found that in warmer regions, demand per HDDW is larger during colder than average winters relative to warmer winters. In colder climates, demand per HDDW tends to be constant regardless of the severity of the winter. The Winter Severity Adjustment corrects for a potential non-linearity in demand per HDD in warmer climates.

99% Confidence Forecast – The 99% Confidence Forecast includes an upward adjustment of the Design Day Forecast by 2.5 forecast standard deviations, which produces a forecast with an approximately 99% confidence level.

Marquette Energy Analytics

99% Confidence Forecast – Illustration

99% Confidence Forecast – The 99% Confidence Forecast includes an upward adjustment of the Design Day Forecast by 2.5 forecast standard deviations, which produces a forecast with an approximately 99% confidence level.



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Forecasting Design Day for Five Years

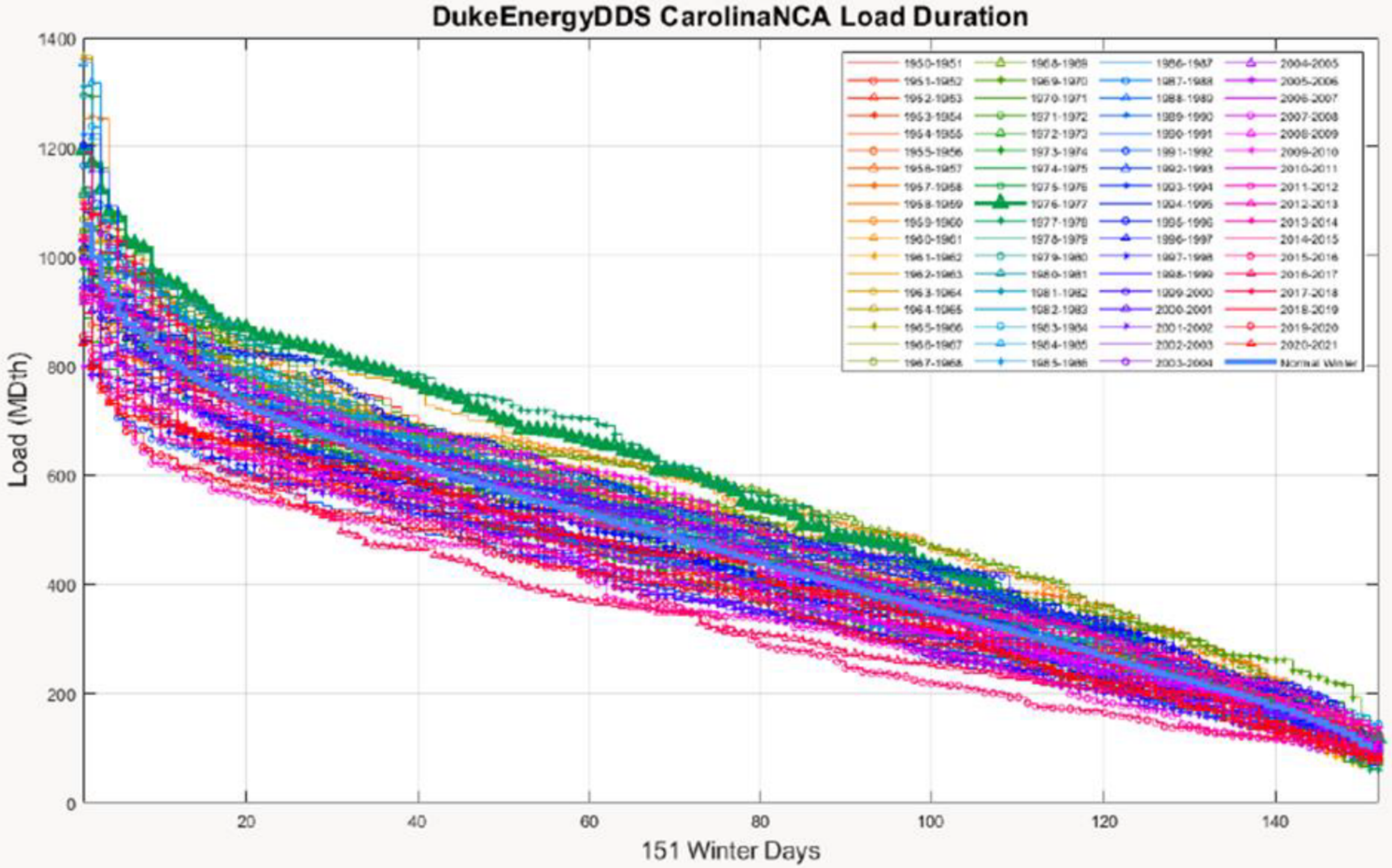
MEA forecasts design day growth out five years using a different methodology, including directly incorporating assumptions about customer growth.

North Carolina West

		2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
Baseload		57,215	56,231	56,485	56,152	55,839
Use/HDDW		15,877	15,983	16,075	16,153	16,227
Baseload Change from 2022-2023			-984	-730	-1,062	-1,375
Use/HDDW Change from 2022-2023			105.28	197.11	275.72	349.65
Heatload Change	59.8		6,296	11,788	16,490	20,911
DDC 59.8 HDDW Estimate for 2022-2023		903,072	903,072	903,072	903,072	903,072
Baseload growth since 2022-2023			-984	-730	-1,062	-1,375
Heatload growth since 2022-2023			6,296	11,788	16,490	20,911
Per Customer Growth Estimate		**903,072**	**908,385**	**914,131**	**918,500**	**922,608**
Number of customer percent increase			1.6%	3.3%	5.1%	6.9%
Number of customer adjustment			14,793	30,412	46,763	63,881
Design Day Forecast		**903,072**	**923,178**	**944,543**	**965,262**	**986,489**
2.5 Standard Deviations	42,595	42,595	42,595	42,595	42,595	42,595
99% Confidence Forecast		**945,667**	**965,773**	**987,138**	**1,007,857**	**1,029,084**

1-in-30 Year Load Duration Curve

MEA uses models of Piedmont's demand, developed in modelling design day demand, along with 72 years of daily data back to 1950 to calculate 72 hypothetical winter load duration curves.



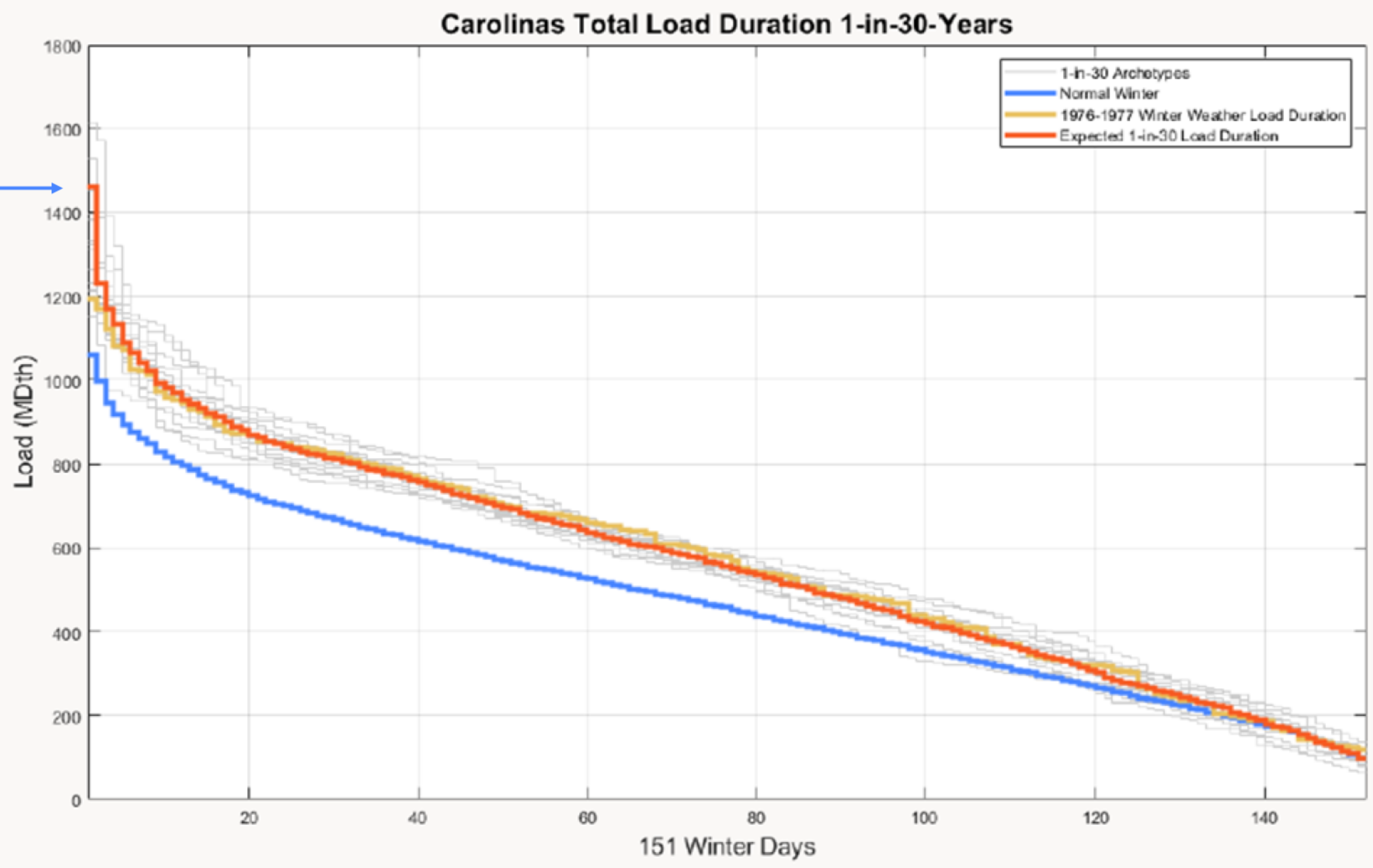
Marquette Energy Analytics

1-in-30 Year Load Duration Curve

From the 72 hypothetical load duration curves, a probability distribution is calculated, and from that, a 1-in-30-year load duration curve is calculated using the 15 highest hypothetical winters as a model.

Constructed to Include the 2022-23 Design Day Demand Forecast of

1,444,893 Dth



BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 811

In the Matter of		
Application of Piedmont Natural Gas	)	**TESTIMONY OF**
Company, Inc., for Annual Review of Gas	)	**JORDAN A. NADER**
Costs Pursuant to N.C.G.S. § 62.133.4(c)	)	**PUBLIC STAFF –**
and Commission Rule R1-17(k)(6)	)	**NORTH CAROLINA**
	)	**UTILITIES COMMISSION**

PIEDMONT NATURAL GAS COMPANY, INC.

DOCKET NO. G-9, SUB 811

TESTIMONY OF

JORDAN A. NADER

ON BEHALF OF

THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 19, 2022

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Jordan A. Nader, and my business address is 430 North Salisbury Street, Raleigh, North Carolina. I am a Public Utilities Engineer in the Natural Gas Section of the Public Staff's Energy Division.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications and experience are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to: (1) present the results of my review of the gas cost information filed by Piedmont Natural Gas Company, Inc. (Piedmont or Company), in accordance with N.C. Gen. Stat. § 62-133.4(c) and Commission Rule R1-17(k)(6); (2) provide my conclusions regarding whether the costs associated with the natural gas purchases made by Piedmont during the review period were prudently incurred; and (3) provide my recommendations regarding temporary rate increments or decrements.

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR REVIEW.

A. I reviewed: (1) the testimony and exhibits of the Company's witnesses; (2) the Company's monthly Deferred Gas Cost Account reports; (3) monthly financial and operating reports; (4) the gas supply, pipeline transportation, and storage contracts; (5) the reports filed with the Commission in Docket No. G-100, Sub 24A; (6) and the Company's responses to Public Staff data requests. The data request responses contained information related to Piedmont's approach to gas purchasing, customer requirements, and gas portfolio mixes. The Public Staff and the Company have also participated in several virtual meetings.

Q. WHAT IS THE RESULT OF YOUR EVALUATION OF PIEDMONT'S GAS COSTS?

A. Based on my investigation and review of the data in this docket, including information provided by the Company through data requests and virtual meetings, I believe Piedmont's gas costs were prudently incurred.

Q. WHAT OTHER ITEMS DID YOU REVIEW?

A. Even though the scope of Commission Rule R1-17(k) is limited to a historical review period, the Public Staff's Energy Division also considers information received in response to data requests in order to anticipate the Company's requirements for future needs, including design day estimates, forecasted gas supply needs, projection of capacity additions and supply changes, and customer load profile changes.

CUSTOMER GROWTH

Q. HOW HAVE PIEDMONT'S CUSTOMERS AND THROUGHPUT CHANGED SINCE THE COMPANY'S LAST ANNUAL REVIEW OF GAS COSTS PROCEEDING?

A. Table 1 below reflects Piedmont's year-to-year customer growth rate of 1.24% in North Carolina. The current review period saw a decrease of 9.23% in Heating Degree Days and a decrease of 9.15% in Wind-adjusted Heating Degree Days as compared to the prior 2020-2021 review period. There was a 3.76% decrease in sales volumes consumption during the prior review period. In addition, Piedmont's North Carolina transportation volumes increased by 27.3% over the prior review period, which is an incremental consumption gross volume increase of 88,754,428 dekatherms (dts). This averages to 243,162 dts/day over the review period.

Table 1: Customer Growth

Piedmont Natural Gas Company Sub 24A	2021 Review	2022 Review	Change
Number of Customers NC&SC (May 31)	937,073	950,220	1.40%
Sales Volumes NC&SC (dts)	88,130,555	85,087,881	-3.45%
Transportation Volumes NC&SC (dts)	375,275,221	464,557,588	23.79%
Total Sales & Transportation Volumes NC&SC (dts)	463,405,776	549,645,469	18.61%
Number of Customers NC (May 31)	782,185	791,920	1.24%
Sales Volumes NC (dts)	73,125,606	70,376,993	-3.76%
Transportation Volumes NC (dts)	325,128,740	413,883,168	27.30%
Total Sales & Transportation Volumes NC (dts)	398,254,346	484,260,161	21.60%
Number of Customers SC (May 31)	154,888	158,300	2.20%
Sales Volumes SC (dts)	15,004,949	14,710,888	-1.96%
Transportation Volumes SC (dts)	50,146,481	50,674,420	1.05%
Total Sales & Transportation Volumes SC (dts)	65,151,430	65,385,308	0.36%

AVAILABLE SUPPLY AND CAPACITY RESOURCES

Q. PLEASE DISCUSS PIEDMONT'S GAS SUPPLY AND PIPELINE CAPACITY DURING THE REVIEW PERIOD.

A. Company witness Patton stated that Piedmont previously contracted for 160,000 dts per day of year-round firm capacity on the canceled Atlantic Coast Pipeline. As stated in witness Patton's testimony, Piedmont has since entered into a contract with Transcontinental Gas Pipe Line Company, LLC (Transco), as part of its Southside Reliability Enhancement (SRE) Project, which he describes as "additional incremental firm pipeline service" targeted to be in service on December 1, 2024. Witness Patton states that this project will provide: (1) 160,000 dts per day of incremental firm pipeline service via Transco's South Virginia Lateral to delivery points in Piedmont's eastern North Carolina service territory; and (2) a separate firm pipeline service path of 263,400 dts per day from Transco's interconnect with Pine Needle LNG to Piedmont's Iredell meter located in Iredell County, North Carolina.

The incremental increase in capacity to be delivered through Transco's SRE Project is not evident in Patton Exhibit_(JCP_5C). Line 22 on Exhibit_(JCP_5C) shows a "Total Year-Round FT" value of 660,720 dts per day for each year through the 2026-2027 Winter Period. Line 45 on the same exhibit designates a total capacity availability of 1,679,055 through the 2026-2027 Winter Period.

On page 7 of its Abbreviated Application for Certificate of Public Convenience and Necessity (Southside Reliability Enhancement), in FERC Docket No. CP22-461 (SRE Project Application), Transco states:

> The Project is an incremental expansion of Transco's existing pipeline system that will enable Transco to provide an additional 423,400 Dth/day of firm transportation service, with 160,000 Dth/day from Transco's existing Station 165 Zone 5 Pooling Point in Pittsylvania County, Virginia, through Transco's South Virginia Lateral to existing metering facilities in Hertford and Northampton Counties, North Carolina, and 263,400 Dth/day from Transco's interconnection with the Pine Needle LNG Company, LLC ("Pine Needle") storage facility in Guilford County, North Carolina, to existing metering facilities in Iredell County, North Carolina.

As noted in the SRE Project Application, Transco has executed a binding, long-term precedent agreement with Piedmont for 100% of the firm transportation capacity to be constructed under the SRE

Project. Id. The SRE Project Application further states that under the SRE Project, Piedmont will be increasing its firm transportation capacity along two paths on Transco's pipeline system. Id. at 19. However, in response to a Public Staff data request asking the Company to clarify whether the 160,000 Dth/day contracted as part of the SRE Project will represent an increase in firm transportation capacity, the Company stated:

> Currently, Piedmont recognizes the 160,000 dth per day ("SVL Path") contracted as part of SRE as a firm transportation path to add flexibility for deliveries of natural gas supply from Transco's mainline to Piedmont's eastern North Carolina system rather than an increase to Piedmont's overall firm transportation capacity.[1]

With the addition of the SRE Project capacity, the Public Staff is of the opinion that the Company potentially has capacity in excess of 34,601 dts for the 2026-2027 winter period. While the contract for this capacity addition was executed during the current review period, it is pending before the FERC and will not materially change supply before December 2024 at the earliest. The Public Staff proposes to work with the Company prior to the filing of the next annual review to address the Company's future supply capacity as recommended by Public Staff witness Metz.

[1] Piedmont response to Public Staff Data Request 5-1(a).

Q. DOES TRANSCO'S SRE PROJECT APPLICATION RAISE ANY OTHER CONCERNS WITH PIEDMONT'S CAPACITY RESOURCES?

A. Yes. Transco's SRE Project Application states

> Every year over the past seven years Piedmont has averaged a withdrawal utilization rate of 76% of its Pine Needle Capacity and has utilized its Pine Needle Capacity[2] an average of 34 days each year. Currently, Piedmont ships its Pine Needle withdrawals on Transco by utilizing secondary or non-secondary reverse path ("NSRP") nominations (described in Section 57 of the General Terms and Conditions of Transco's FERC Gas Tariff). Secondary and NSRP nominations receive a lower priority of service than primary firm nominations, meaning if Transco's system is being fully utilized by primary firm shippers at any point between Pine Needle and Piedmont's delivery points, Piedmont's nominations will be allocated (cut). Every year over the past 7 years Piedmont has relied solely on this lower priority, secondary service to access its Pine Needle Capacity.

SRE Project Application at 22-23.

Transco noted that its Zone 5 mainline has seen secondary and NSRP nominations constrained "on average 90% of the year over the past three years." Id. at 23.

Given the above, the Public Staff requested clarification from Piedmont regarding how Pine Needle LNG could be considered a design day planning resource prior to the completion of Transco's SRE Project. Piedmont responded that shale gas flows have

[2] "Pine Needle Capacity" is defined as a total storage capacity of 2,634,000 Dth.

changed the characteristics of Transco's system operations, leading to the inability to flow Pine Needle Gas backhaul towards Iredell (north to south). Piedmont noted that it is "taking steps to establish primary firm delivery rights for that capacity beginning in 2024 with the completion of Transco's SRE project."[3]

Based on the foregoing, the Public Staff is concerned about Pine Needle LNG's availability on a design day at this time. To highlight the potential shortfall, I have included the Public Staff's Modifications to Patton Exhibit_(JCP_5C) as Exhibit 1 to my testimony. As indicated in Public Staff witness Metz's testimony, it is unclear if or when the Company will utilize MEA's design day results. Without certainty for design day planning, I am unable to determine the short- and long-term ramifications of such a shortfall. As such, it is appropriate for Piedmont to find a solution to this shortfall for the next two winter periods prior to the completion of the SRE Project that does not increase costs for ratepayers.

DEFERRED ACCOUNT BALANCES

Q. WHAT IS YOUR RECOMMENDATION REGARDING ANY PROPOSED INCREMENTS/DECREMENTS?

[3] Piedmont Supplemental Response to Public Staff Data Request 5-4d.

A. Public Staff witness Johnson states in her testimony that the All Customers' Deferred Account Balance of $36,906,871 owed by the Company to the customers is appropriate as filed by the Company. As stated in witness Johnson's testimony, the Public Staff recommends transferring the credit balance of ($18,021,467) in the Hedging Deferred Account to the Sales Customers' Only Deferred Account. The net debit balance as of May 31, 2022, would be $14,895,828 owed by the customers to the Company.

Company witness Tomlinson did not propose any new increments or decrements. The Public Staff notes that the deferred account balances of local distribution companies (LDCs) vary between winter and summer months, as gas costs are typically over-collected during the winter period when throughput is higher due to heating load and under-collected during the summer due to lower throughput.

The Public Staff generally recommends that gas LDCs monitor the deferred account balances and, if necessary, file an application for authority to adjust their benchmark cost of gas and/or temporary rate per dt; however, I believe the Company is actively managing its deferred account through the PGA procedures. On September 16, 2022, Piedmont filed a petition in Docket No. G-9, Sub 813, seeking approval to increase its rates and charges effective October 1, 2022, as a result of the net effect of: (1) a proposed increase in its

Benchmark Cost of Gas from the current rate of $6.00 per dt to a rate of $8.25 per dt; and (2) a reduction in the demand charge component of its rates.

Q. DOES THIS CONCLUDE THE PUBLIC STAFF'S TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JORDAN A. NADER

I graduated from The Ohio State University with a Bachelor of Science degree in Mechanical Engineering in 2014 and the University of Dayton with a Master of Science degree in Mechanical Engineering in 2017.

Prior to joining the Public Staff, I worked in Ohio as an Energy Engineer with Go Sustainable Energy, LLC. During that time, I conducted industrial energy audits, provided third party measurement and verification of electric utility energy efficiency programs, and commissioning work for local library system. In addition, I worked as an Analyst for Runnerstone, LLC, providing technical expertise and analysis to large energy users in Ohio. This included quantifying the potential costs of pending legislation and/or regulation and the impacts it could have on ratepayers.

I joined the Public Staff in November of 2021 as a member of the Natural Gas Section of the Energy Division. My work to date includes Integrity Management Review, Annual Review of Gas Costs, and Design Day Demand and Capacity Calculations.

G-9, Sub 811
Public Staff - Nader Exhibit 1

Public Staff's Modifications to Patton Exhibit_(JCP-5C)
Docket No. G-9 Sub 811

Exhibit_(JCP-5C)

Carolinas Design Day Demand & Supply Schedule - Winter 2022 - 2023 w/Pine Needle LNG Reduced

Design Day Temperature Wind Adjusted (wgt.avg.) of 6.7 Degrees (58.3 HDDWs)

Line	(All Values in Dt/d)	Type of Contract	Days		2022 - 23	2023 - 24	2024 - 25	2025 - 26	2026 - 27
			Carolinas Demand Growth Rate		1.4281%	1.8302%	2.0067%	1.9034%	1.9277%
	DEMAND		**Winter Period**		**2022 - 23**	**2023 - 24**	**2024 - 25**	**2025 - 26**	**2026 - 27**
1	System Design Day Firm Sendout				1,444,893	1,471,338	1,500,864	1,529,431	1,558,914
2	Mid Year Firm Sales Pick Up				**1,379**				
3	Mid Year Firm Sales Deduct (move to Firm Transport)				**(3,776)**				
4	Subtotal Sendout plus Mid Year Pickup				1,442,497	1,471,338	1,500,864	1,529,431	1,558,914
5	Special Contract Firm Sales Commitment				**7,233**	7,233	7,233	7,233	7,233
6	Total Firm Design Day Demand				1,449,730	1,478,571	1,508,097	1,536,664	1,566,147
7	Reserve Margin on Design Day Demand (5%)				72,487	73,929	75,405	76,833	78,307
8	***Total Firm Sales Demand***				**1,522,216**	**1,552,500**	**1,583,502**	**1,613,497**	**1,644,454**
9									
10	***SUPPLY CAPACITY***								
11	***Firm Transportation***	***Type of Contract***	Days						
12	**Transco**	FT	365		301,016	301,016	301,016	301,016	301,016
13	**Transco**	FT	365		6,440	6,440	6,440	6,440	6,440
14	**Transco**	FT SE '94/95/96	365		129,485	129,485	129,485	129,485	129,485
15	**Transco**	Sunbelt	365		41,400	41,400	41,400	41,400	41,400
16	**Transco**	VA Southside	365		20,000	20,000	20,000	20,000	20,000
17	**Transco**	Leidy	365		100,000	100,000	100,000	100,000	100,000
18	**Columbia Gas**	FTS	365		9,801	9,801	9,801	9,801	9,801
19	**Transco SRE (Columbia Gas Upstream)**	FTS	365	[3]	23,000	23,000	23,000	23,000	23,000
20	**Columbia Gas**	NTS	365		10,000	10,000	10,000	10,000	10,000
21	**Transco SRE (East TN & MGT & Upstream)**	FT	365	[3]	19,578	19,578	19,578	19,578	19,578
22	***Total Year Round FT***				660 720	660 720	660 720	660 720	660 720
23									
24	**Transco**	FT Southern Expansion	151		72,502	72,502	72,502	72,502	72,502
25	**Transco SRE (East TN & TETCO Upstream)**	FT	151	[1,3]	24,798	24,798	24,798	24,798	24,798
26	**Transco**	FT	90		6,314	6,314	6,314	6,314	6,314
27	***Total Winter Only FT***				103,614	103,614	103,614	103,614	103,614
28									
29	***Firm Transportation Subtotal***				**764,334**	**764,334**	**764,334**	**764,334**	**764,334**
30									
31	**Transco SRE (Hardy Storage Upstream)**	HSS	70	[3]	68,835	68,835	68,835	68,835	68,835
32	**Transco SRE (Columbia Gas Upstream)**	FSS/SST	59	[3]	86,368	86,368	86,368	86,368	86,368
33	**Transco**	GSS	55		77,475	77,475	77,475	77,475	77,475
34									
35	***Total Seasonal Storage***				**232,678**	**232,678**	**232,678**	**232,678**	**232,678**
36									
37	***Peaking Capacity***								
38	**Piedmont**	LNG - Huntersville	10		100,000	100,000	100,000	100,000	100,000
39	**Piedmont**	LNG - Bentonville	9		110,000	110,000	110,000	110,000	110,000
40	**Transco**	Pine Needle	10		0	0	263,400	263,400	263,400
41	**Transco**	LNG (formerly LG-A)	5		8,643	8,643	8,643	8,643	8,643
42	**Piedmont**	LNG - Robeson	5	[2]	200,000	200,000	200,000	200,000	200,000
43	***Peaking Supplies Total***				**418,643**	**418,643**	**682,043**	**682,043**	**682,043**
44									
45	***Total Capacity***				**1,415,655**	**1,415,655**	**1,679,055**	**1,679,055**	**1,679,055**
46					**(106,561)**	**(136,845)**	**95,553**	**65,558**	**34,601**

[1] *East TN capacity is 365 days, however the upstream TETCO capacity delivering to East TN is 151 days*
[2] *During the Review Period, construction of the Robeson LNG plant was completed, and it was placed in service in August 2021.*
[3] *Transco SRE project has a target in-service date of December 1, 2024. This project will provide deliverability of 160,000 Dth per day (365 days) from Transco's South VA Lateral with upstream supply from existing non-Transco Zone 5 priced supply contracts (TCO 23,000, ENT/MGT 19,578, ETN/TETCO 24,798, TCO/FSS 81,169 and Hardy 11,455)*