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November 1, 2023

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: Eversource Gas Company of Massachusetts d/b/a Eversource Energy, D.P.U. 23-125
2023/2024 – 2027/2028 Forecast and Supply Plan

Dear Mr. Marini:

On behalf of Eversource Gas Company of Massachusetts d/b/a Eversource Energy (the "Company"), enclosed is the Company's Long-Range Forecast and System Gas Supply Resource Plan (the "F&SP"), submitted pursuant to G.L. c. 164, § 69I, for the forecast period of November 1, 2023 through October 31, 2028.

In this filing, the Company presents its forecasting methodology and resource-planning process, along with a strategic resource plan based on the current forecast of customer requirements and market conditions. Approval of the Company's FS&P is warranted because the plan is in compliance with the demand forecasting and integrated resource planning standards and methods set by the Department of Public Utilities.

Accompanying this letter is a Notice of Appearance relating to this docket. Should you have any questions regarding the information provided with this filing, please do not hesitate to contact me directly.

Thank you for your attention to this filing.

Very truly yours,

Steven Frias

Encl.
cc: George Yiankos, Director, Gas Division
Elizabeth Anderson, Assistant Attorney General
Matthew Saunders, Assistant Attorney General

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Eversource Gas Company of Massachusetts d/b/a Eversource Energy	))))	D.P.U. 23-125

APPEARANCE OF COUNSEL

In the above-referenced proceeding, I hereby appear for and on behalf of Eversource Gas Company of Massachusetts d/b/a Eversource Energy.

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Dated: November 1, 2023

EVERSOURCE GAS COMPANY OF MASSACHUSETTS

2023
LONG RANGE FORECAST AND
SUPPLY PLAN
2023/2024 – 2027/2028

Submitted to:

Massachusetts Department of Public Utilities

November 1, 2023

APPENDICES

I. INTRODUCTION

The purpose of this report by Eversource Gas Company of Massachusetts ("EGMA" or the "Company")[1] is to present the long-range forecast and supply plan (the "F&SP" or the "Plan") for the period November 1, 2023 through October 31, 2028. The F&SP details EGMA's resource-planning process and presents the Company's resource requirements based on a forecast of customer demand and prevailing market conditions. EGMA submits this F&SP for review and approval by the Department of Public Utilities (the "Department") pursuant to G.L. c. 164, § 69I. The Department's approval of the Company's F&SP is warranted because the F&SP sets forth a resource plan to meet expected customer requirements using the Department's established forecasting planning processes, standards and methods.

The Company's F&SP meets the Department's established standards for approval under G.L. c. 164, § 69I. The F&SP provides a complete description of the planning processes employed by the Company, which will enable the Department to adequately review the Plan and to come to a full understanding of the methods used and the results reached by applying those methods to current circumstances. The Plan demonstrates that EGMA's planning standards are appropriate and that the resource strategies described herein are in the best interest of customers and result in a reliable, long-range, least cost supply to meet the Company's forecasted firm demand. Lastly, the Plan demonstrates that the Company's resource portfolio is sufficient to meet design day, design winter and design year requirements, as well as demand that could be expected during a cold snap.[2]

A. OVERVIEW OF EGMA SERVICES AND RESOURCES

EGMA provides local distribution service to over 333,000 customers residing in three separate operating divisions, located in areas of Massachusetts surrounding the major cities of

1 In October 2020, EGMA became the successor in interest to Columbia Gas of Massachusetts as part of a settlement approved by the Department. Joint Petition of Eversource Energy, Eversource Gas Company of Massachusetts, NiSource Inc. and Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of Purchase and Sale of Assets Pursuant to General Laws Chapter 164, §§ 94 and 96, D.P.U. 20-59 (2020).

2 The required Energy Facilities Siting Board ("EFSB") tables are set forth in Appendix 3.

Brockton, Springfield and Lawrence. The majority of EGMA's customer base is comprised of residential customers. The remainder of EGMA's customers are traditional small and medium-size commercial and industrial ("C&I") customers, as well as some larger industrial customers. The forecast aggregate design day demand for sales customers ("Planning Load") on EGMA's system for the upcoming winter is approximately 521 MDth, including the expected demand-side resource offsets. Normal annual requirements are expected to be about 55.9 MMDth in the initial year of the Plan.

All of EGMA's customers have the option of purchasing supply from a competitive supplier and receiving transportation-only service from EGMA, pursuant to the Company's unbundled tariff options. EGMA has numerous customers being served by seven suppliers. The terms and conditions applicable to transportation-only service specify EGMA's obligation to assign capacity to portions of the transportation customer loads in each division. EGMA's resource planning process appropriately reflects its obligation to assign capacity and maintain reliability in conjunction with its unbundled service offerings.

EGMA's current resource portfolio is comprised of long and short-haul transportation capacity, storage capacity and associated transportation capacity, city-gate and off-system peaking supplies and on-system peak-shaving facilities. All of EGMA's upstream long- and short-haul transportation capacity and underground storage and city-gate peaking supplies are ultimately delivered to the Company's divisions located off of the Tennessee Gas Pipeline Company ("Tennessee" or "TGP") and Algonquin Gas Transmission, LLC ("Algonquin" or "AGT") pipelines. EGMA's on-system peaking facilities include on-system liquid propane gas ("LPG") and liquefied natural gas ("LNG") facilities located within each of its divisions as well as off-system peaking services that provide deliveries to the Brockton, Springfield and Lawrence Divisions. The combination of base load, winter and peaking resources provides a diverse, reliable and cost-effective means of serving EGMA's overall firm customer and associated demand profile.

B. STANDARD OF REVIEW

The Department assesses each LDC's long-range planning standards, demand forecasting methods and resultant design and normal sendout forecasts in order to determine if they are reviewable, appropriate, and reliable. A forecast method is reviewable, if it "contains enough information to allow a full understanding of the forecast methodology"; appropriate, if it is "technically suitable to the size and nature of the particular gas company;" and reliable, if it "provides a measure of confidence that the gas company's assumptions, judgments, and data will forecast what is most likely to occur." Bay State Gas Company, D.P.U. 08-79, at 2 (2010). The Department also reviews an LDC's long-range demand forecasts to ensure that it has accurately projected gas sendout requirements of the utility's market area. Lastly, the Department reviews an LDC's supply planning process and the resulting resource portfolio with an emphasis on adequacy and cost. The Department's review of an LDC's supply plan investigates whether the portfolio is adequate to meet forecast firm requirements under design year, design day and cold-snap conditions for the base case. In instances where the portfolio is not adequate to meet the base case of forecast requirements, the LDC must demonstrate that it has an adequate Action Plan to address any deficiency.

C. ORGANIZATION OF THE FORECAST AND SUPPLY PLAN

This Plan is organized into six sections, including this Section I (Introduction). Section II provides a summary of the current resource planning environment, the Company's resource planning objectives and goals, and the resource planning process prior to examining each of the Plan's elements in more detail. Also, Section II summarizes the Company's resource planning tools.

Section III presents EGMA's Demand Forecast, including: (a) an overview of the methodology that EGMA followed to prepare the F&SP demand forecast; (b) a description of the forecast models that were developed for this F&SP and a summary of the model results; (c) projected customer demand offsets due to energy efficiency ("EE") or demand-side resources; (d) a summary of the derivation of the resource requirements, or "planning load" that EGMA used to assess the adequacy of its resources, including the derivation of several scenarios to reflect weather-related extremes and optimistic and pessimistic economic scenarios; and (e) a description for the derivation of the weather-related extremes, or "planning standards" used to derive estimates of future design day, cold snap and normal and design winter requirements, which are all used in the Company's portfolio optimization model.

Section IV describes the Company's current resource planning process, including special considerations given to today's planning environment and supply-side resource strategies based on current customer requirements and market conditions. Section V summarizes EGMA's Action Plan. Lastly, Section VI states EGMA's conclusion regarding its resource plan. The required Energy Facilities Siting Board ("EFSB") tables, plus supporting detail for the demand forecast and the resource assessment, are provided in the appendices to this report. EGMA's Plan incorporates flexibility and reflects expected future conditions. It is a dynamic living document in the sense that it continues to be refined as needed in order to reasonably respond to the changing requirements of EGMA's customers and market conditions. Supply requirements are planned for and procured within a dynamic environment involving a marketplace influenced by various economic conditions. Therefore, the Company's decisions will be based on current assessments of the best information known at the time that are subject to change. All assessments, however, will be based upon the methodology set forth in this Plan.

II. OVERVIEW OF RESOURCE PLANNING PROCESS

EGMA's resource planning process begins with the establishment of appropriate goals and objectives. The primary goal of EGMA's planning process is to acquire and manage resources in a manner that achieves a least-cost resource portfolio for its customers. A least-cost portfolio appropriately balances resource cost with EGMA's other planning objectives, which are to maintain the security and reliability of supply, provide contract flexibility and pursue the acquisition of viable resources. Pursuit of a least-cost portfolio allows EGMA to provide its customers with reliable service at the lowest possible cost, consistent with the planning criteria required by G.L. c. 164, § 69I and Department precedent. In addition, EGMA's resource planning process incorporates the current status of market restructuring in natural gas markets.

A. CURRENT RESOURCE PLANNING ENVIRONMENT

Market and regulatory restructuring of wholesale and retail natural gas markets over the last few decades have increased the complexity associated with acquiring and managing a least-cost resource portfolio. Virtually every aspect of LDC portfolio management has been transformed by regulatory and market changes. In the broadest of terms, the very markets that LDCs such as EGMA participate in, the types of products and services that are bought and sold, and the manner in which these transactions are completed are vastly different today than they were 40, 30 or even 20 years ago. Market transformation has brought about many new opportunities and risks for all market participants, including LDCs, which must continue to reliably meet the supply requirements of their customers.

Natural gas markets continue on a course of broad restructuring that began with the initial deregulation of most wellhead supply prices starting in 1978 through an act of Congress. Through a series of physical infrastructure, financial market, regulatory and technological advances, the manner in which gas supplies are traded and delivered to end-use customers has changed entirely. Whereas in the past, an LDC or end user might have only been able to procure gas from one or two entities, today there are many more available choices in the production areas like Marcellus Shale and other areas. The result is a dynamic and more competitive marketplace for gas in upstream markets that is capable of delivering greater value to customers, but also increases the complexity of resource planning.

Wholesale natural gas commodity markets are no longer price-regulated and the delivery of supplies to LDC city-gate stations is unbundled from supply and storage services. Large volumes of gas are traded at many different pooling points along the interstate pipeline transmission system at transparent prices. LDCs, and even many end users, purchase supplies directly from marketing entities offering flexible contract terms. Additionally, natural gas contracts are among the most actively traded futures and options in financial markets. Even pipeline and storage capacity services are actively traded under more flexible terms in the primary and secondary release markets.

The U.S. natural gas industry has experienced significant change over the past fifteen years, including the discovery and production of natural gas from prolific shale gas deposits. The increasing domestic production of natural gas has resulted in numerous changes to not only the broader U.S. natural gas market, but also to the New England region. Specifically, in the New England region, the increase in domestic natural gas supplies has generally resulted in lower annual natural gas prices and an increase in the demand for natural gas with the most recent market volatility due to the COVID-19 pandemic, geopolitical issues and other market forces.

These changes in natural gas markets have brought greater competition and customer choice along with increased market instability and uncertainty, substantially complicating the factors involved and manner in which an LDC forecasts customer demand and designs its resource portfolio. As the Department recognized in its investigation into the appropriate capacity assignment methodology, unlike electricity markets, for example, gas markets do not have centralized bodies such as independent system operators that can effectively take responsibility for regional reliability. With the introduction of competition from marketers, the LDC remains responsible for ensuring the supply reliability for its firm sales and non-capacity exempt firm transportation customers (i.e., "Planning Load"), a responsibility that can be more challenging with the reliance of marketers to deliver supply to their capacity exempt customers. But the Department has recently found that capacity and supply to discrete regions of the Company's service territory may not be readily available to the marketplace which has lead to operations issues on system supplies and as such the Company should include requirements for exempt needs in its planning. As the Department has found in its decision for a mandatory capacity assignment construct, the responsibility of ensuring supply reliability for the then-existing firm customer base is an appropriate role that EGMA and other LDCs must fulfill until upstream gas markets are sufficiently robust to be relied upon for the provision of reliable, low-cost gas deliveries.

Today's marketplace is witnessing another fundamental change that is reinforcing the need for LDC's to manage the responsibility to supply their customers under design conditions. As the New England region grapples with how to counter the drastic impacts of climate change, a new reality has impacted how to access new sources of supply to reliably serve existing and new customers. The public has become increasingly more vocal in its opposition to any new gas infrastructure to be added in New England that would help alleviate bottlenecks that would allow access to new supplies sourced out of the Marcellus region. As a result, there is not enough infrastructure in place in New England to adequately serve the demand of both LDC load and the gas fired generators service New England's Electric load. Electric generators are now the largest single consumers of natural gas in New England, yet the vast majority of these consumers do not have enough pipeline capacity to supply their needs during the winter months. This has led to regional pipelines that consistently operate at maximum capacity, winter prices in Massachusetts that are forecasted to be far higher than other parts of the country and a dramatic reduction in the flexibility historically experienced on the pipelines that serve New England. Currently access to incremental supplies to serve LDC growth is limited to imported LNG from either the Everett or Canaport or other LNG facilities that can provide supplies from the backend of the pipeline system that does not require pipeline expansions to serve incremental growth. Relying on imported LNG to serve demand exposes LDC's to cost that are set by volatile global LNG markets during winter months.

The reality of new regulations and our collective work to address the effects of rising greenhouse gas levels that are impacting climate change is that the LDC's role in planning process is even more vital to ensure the reliability of service its customers during the transition to more environmentally friendly economy. To help reduce the need for new gas supplies, EGMA's customers continue with their strong energy conservation and efficiency efforts. The Company offers a comprehensive set of energy efficiency ("EE") programs for residential, low-income, and C&I markets. These programs are developed as part of the statewide EE effort pursuant to an Act Relative to Green Communities, Chapter 169 of the Acts of 2008, which was designed to promote enhanced energy efficiency throughout the Commonwealth through "the acquisition of all available energy efficiency demand reduction resources that are cost effective or less expensive than supply." G.L. c. 25, § 21(b)(1). Stable energy prices and Company-sponsored EE measures wherever cost effective have helped to increase customer-driven conservation.

The Company continues to be engaged with regional stakeholders to assess the future of natural gas and explore alternative supply options as part of number of initiatives:

I. Electrification

The company includes assumptions for electrification of natural gas customers in its energy efficiency reductions that reduce the forecasted demand as show in section III. The scale, pace and scope of electrifying of natural gas customers will ultimately be directed by customers response to the outcomes of the two policy making processes in Massachusetts highlighted below.

i. Future of Gas Proceeding (D.P.U. 20-80)

Eversource has been an active participant, along with other stakeholders, in the D.P.U. 20-80 proceeding, which is an investigation into and proceeding on the future role of the natural gas systems in Massachusetts opened by Department on October 29, 2020. This investigation and proceeding directed the Massachusetts gas distribution companies to investigate how they will meet the state emissions reduction mandates by 2050 while also maintaining safe, reliable and affordable service for customers. The investigation is evaluating alternative pathways to decarbonize which may involve, but is not limited to, combinations of electrification, biogas (renewable natural gas and hydrogen), networked geothermal, and deep energy efficiency measures. This process has been intended to involve all stakeholders across the Commonwealth and invited them to share perspectives and feedback on decarbonizing the natural gas systems. Eversource and its peers are approaching decarbonization seriously and in a technology agnostic way to ensure a safe, cost-effective and successful transition to meet the Commonwealth's 2050 goals. The Company awaits the final order and directives in this investigation that will ultimately impact the pace, scale and scope of electrification and other alternatives of the natural gas customers.

ii. Clean Heat Standard

The Massachusetts Clean Energy & Climate Plan for 2025 & 2030 (CECP) tasks Massachusetts DEP with developing a "a high-level program to meet the emissions limit for residential, commercial, and industrial heating" and identifies a Clean Heat Standard (CHS) as a regulatory option for addressing this requirement. The clean heat standard is a regulation that would apply to providers of heating energy in Massachusetts, notably gas utilities and importers of heating oil and propane. These obligated parties would be required to serve Massachusetts' residential and commercial customers with gradually increasing percentages of low carbon heat services so that sales of fossil fuels are phased down. Over time, the goal of the clean heat standard would be to replace pipeline gas, fuel oil and propane heat with heat pumps, clean district energy, weatherization, and other verified low-carbon options. The Company awaits the next steps in this rulemaking process that will ultimately impact the pace, scale and scope of electrification and other alternatives of the natural gas customers.

II. Demand Response Pilot

Eversource is entering the second winter season of its gas demand response pilot among EGMA customers. During the 2022-2023 season, Eversource enrolled 2,000 residential and 5 small commercial customers. A full evaluation of the impacts of the program on peak gas demand is underway.

III. Networked Geothermal Pilot

Eversource is currently in the construction phase of its networked geothermal demonstration pilot project to test the technology at utility scale in a dense, urban, mixed use setting in Framingham, MA part of its NSTAR Gas service territory. The Company intends to test three main concepts informed by this pilot:

- Can networked geothermal be a fiscally sound business line offering that the Company can provide to its customers?
- Does networked geothermal provide increased environmental benefits to the Company and its customers?
- Do the customers receive the space conditioning desired and needed?

If the pilot project is deemed successful, the Company looks forward to expanding its networked geothermal offerings to customers including within the EGMA footprint.

IV. Renewable Natural Gas

As longer term decarbonization solutions are being analyzed and vetted, the Company continues to look for ways to reduce emissions currently or in the near term while maintaining the expected level and cost of service to customers. The Company continues to look for renewable natural gas ("RNG") opportunities to provide to customers while also mitigating renewable natural gas premiums and in the absence of regulatory cost recovery framework. RNG offers a low or no carbon solution for customers while also utilizing the existing natural gas infrastructure with minimal modifications and reducing overall emissions, in some cases for other industries such as agriculture.

V. Hydrogen

The Company also continues to research and develop clean hydrogen opportunities, especially for its large commercial and industrial customers to compliment electrification efforts or to provide as a decarbonized option for hard to electrify end-users. From a hydrogen perspective, the advent of the Company's offshore wind assets may provide a clean and cost-effective partnership with the existing natural gas infrastructure in the future.

B. CURRENT AND FUTURE MARKET CONDITIONS

The most recent expansions of pipeline capacity sponsored by the LDCs into the New England market included the Algonquin "AIM" project (342,000 MMBtu/day) which was placed into service during the winter of 2016-17 and the Algonquin "Atlantic Bridge" project (133,000 MMBtu/day) which was partially placed into service in 2017-18 and which went into full service on October 1, 2019. Both Tennessee (TGP) and Algonquin (AGT) planned to expand to serve gas fired electric generation load with their proposed Northeast Direct project (NED) and Access

Northeast (ANE) project respectively, but both projects were dropped when the Massachusetts Supreme Judicial Court determined that the Department did not have the authority to approve contracts that would have allowed Electric Distribution Companies (EDCs) the ability to pass on the costs of pipeline capacity to the EDC's customers.

Several Massachusetts LDCs had contracts with TGP for NED capacity. Once the NED project was terminated, an alternative approach was developed that would deliver incremental gas supplies from Dawn, Ontario to the Portland Natural Gas Transmission System interconnection with TransCanada and subsequently to TGP New England Customers. EGMA was one such customer and the Department approved its pipeline contracts in D.P.U. 17-172 on May 31, 2018. The order approved the TGP Zone 6 to Zone 6 contract for 96,400 Dth/day, a PNGTS expansion of 14,300 Dth/day and a peaking services contract with Repsol for deliveries at Dracut, MA. The TGP contract was initially in service in November 2018 at 50,000 Dth/day, increased to 76,000 Dth /day in Nov 2020 and reached full delivery of 96,400 Dth on November 2021.

Although production of shale gas in the Marcellus and Utica basins primarily in Pennsylvania and Ohio has continued to grow in recent years, incremental supplies can't reach the New England market because of pipeline capacity constraint. The pipeline infrastructure in the region remains constrained and reliant upon LNG imports Repsol via Canaport, Constellation LNG via the Everett Marine Terminal and Excelerate via the buoy in Boston Harbor for its marginal supply. Notably, the future of the Everett Marine LNG Terminal remains in question with the expiration of its parent company's agreement with ISO New England in June 2024. Gas-fired electric generators still want to use natural gas to fuel their facilities, but their unwillingness to pay for incremental pipeline capacity means that the New England gas market will continue to suffer from high delivered gas costs during the winter season. The LDCs cannot solve the region's supply issues. Instead, the LDCs have an obligation to their customers to maintain the reliability of natural gas distribution and supply service and the LDCs will take all necessary steps within their control to assure that their customers have heat on cold winter days.

C. EGMA's Planning Process

This section of the Plan provides an overview of the various elements of EGMA's planning process, and how each of the elements interact. This planning process has been approved, most recently in D.P.U. 21-118, by the Department and in other past F&SP proceedings. Each element is described in detail in the following sections of the Plan.

Appendix 1 provides a simplified representation of EGMA's resource planning process. The process encompasses three major elements: (1) a forecast of requirements; (2) a resource evaluation; and (3) a resource action plan. Although EGMA has employed the same general planning framework for a number of years, the Company continues to refine its methods and to update the data relied upon in order to continually improve its planning process.

As more completely described in Sections III.A and III.B, EGMA's planning process begins with an assessment of customer requirements. EGMA employs econometric modeling techniques to generate its base case forecast of Planning Load. Forecasts are generated separately for four customer segments: residential heat, residential non-heat, C&I low load factor, and C&I high load factor, by division, based on models that independently estimate the number of customers and their associated usage per customer. The development of the forecast models relies on a number of important data sources including historical customer count, usage, and demographic and economic variables. In addition to a base case forecast, EGMA also prepares optimistic and pessimistic economic scenarios to establish a range of reasonably expected customer requirements to test the Company's portfolio under higher and lower than expected demand. The impact of projected energy efficiency savings is included in customer forecast requirements as part of the Plan.

The primary design criterion that drives EGMA's customer requirements is weather. EGMA performs statistical analyses of historical weather data to derive planning standards related to normal year, design winter, cold snap and design day conditions. Resource adequacy is always measured against design conditions derived from these planning standards.

The second aspect of EGMA's planning process is resource evaluation. EGMA's resource evaluation encompasses a number of techniques that comprise a thorough process. Resource evaluation begins with a determination of resource need. Determination of need is accomplished initially by comparing current daily and seasonal capacity resources to projected design day and design winter customer requirements, which include energy efficiency measures. Further analysis of need is undertaken by simulating EGMA's existing portfolio utilizing the SENDOUT® Optimization Model ("SENDOUT®") based on its current design winter, design year and cold snap requirements forecasts. If a need for additional resources is determined, then EGMA identifies the potential resources that are available to meet its customer requirements. These resources may include renewal or restructuring of existing resources as well as acquisition of additional pipeline, storage, city-gate-delivered or on-system resources.

Resource evaluation encompasses the assessment of both the cost and non-cost characteristics of potential available resources. Sophisticated cost analysis is performed utilizing SENDOUT®, which evaluates the cost impact of changes to EGMA's portfolio by simulating the daily dispatch of available resources under specified conditions over a defined period of time. SENDOUT® also possesses the capability to size a least-cost incremental resource or package of resources based on the total cost impact upon the existing portfolio, including fixed costs. EGMA conducts cost analyses based upon the base and high case forecasts, as well as under design conditions. Separately, EGMA evaluates the non-cost characteristics of alternative resources like supply security, contract flexibility and supplier viability. Evaluation of the non-cost characteristics is accomplished through appropriate assessment techniques and scoring.

The Company employs the Total Resource Cost ("TRC") test, as required and approved by the Department in its Order in D.P.U. 08-50-A to analyze the cost effectiveness of its gas energy efficiency programs. The TRC test measures the value of avoided gas supply and any additional direct economic benefits against the costs of a program to participating customers. The avoided gas supply costs used in these cost-effectiveness determinations are based on reports prepared for the avoided energy supply component ("AESC") study group, as part of the statewide energy efficiency process.

D. EGMA'S RESOURCE PORTFOLIO

An important focus of EGMA's Plan is the effective management of resources in its portfolio, including the minimization of the associated current and future costs of this portfolio. During the forecast period, a number of resource decisions must be made primarily related to the potential renewal or replacement of several individual supply, transportation and storage resources that currently comprise EGMA's least-cost portfolio. Those decisions, needed to be made within the first two years of this forecast period, some of which are subject of approval through the Department's decision of this Plan, are identified and discussed later in Section IV. Several upstream pipeline capacity contracts require notice of renewal or termination one year in advance, and others require an even longer notice. The analysis of renewal or replacement of specific expiring resources, as well as the acquisition of incremental resources, must take place early in the planning process for EGMA to appropriately evaluate all alternatives.

Highlights of EGMA's current resource portfolio are as follows:

- <u>Tennessee Transportation and Storage Capacity Contracts</u>: These contracts provide for the delivery of Gulf Coast and/or Appalachian sourced supplies via long-haul transportation capacity, access to market-area storage capacity and short-haul transportation capacity from the United States border at Niagara and other locations where EGMA imports or receives its Canadian supplies including Iroquois and PNGTS, transported to the border by Union and TCPL. Since EGMA's Springfield and Lawrence Divisions are served solely by the Tennessee pipeline, it is critical that EGMA retain all of its primary delivery-point capacity on Tennessee. The Tennessee capacity are legacy contracts and/or provide a competitively priced service offering and important supply diversity benefits to the portfolio.
- <u>Algonquin Gas Transmission Transportation Capacity Contracts</u>: Supplies transported on Algonquin include production from the U.S. Gulf Coast, Appalachian supply basins, and Canadian supply basins, and transportation of storage supplies from TETCO and

EGTS[3]underground storage facilities. Algonquin is the sole supplier to the Brockton Division customers and EGMA must retain primary delivery point capacity to ensure continued service reliability. In addition, most Algonquin contracts are legacy contracts, which represent the most economic transportation option for EGMA's Brockton Division customers.

- Iroquois Gas Transmission System, L.P. ("Iroquois") Transportation Capacity Contract: EGMA has one contract on Iroquois for transportation of underground storage volumes and pipeline supplies from Dawn, Ontario onto Tennessee that provides for deliveries to all EGMA's service areas.

- National Fuel Gas Supply Corporation ("National Fuel") Transportation and Storage Capacity Contracts: EGMA has storage and transportation legacy contracts with National Fuel that provide for the delivery of underground storage supplies into Tennessee for transport to the Company's Springfield and Lawrence Divisions. These legacy contracts provide much needed balancing flexibility and supply reliability.

- Eastern Gas Transmission and Storage (EGTS) formally Dominion Transmission Inc. ("DTI") Storage Capacity Contracts: EGMA has legacy storage capacity with EGTS that provides for the delivery of underground storage supplies to Texas Eastern Transmission, LP ("TETCO") for transport to the Company's Brockton Division. This contract provides much needed balancing flexibility and supply reliability for customers.

- Union Gas Transportation Contract: The Company has two firm transportation contracts on Union, which provides access to supply and storage at the Dawn Hub for ultimate delivery to all three divisions.

- Texas Eastern ("TETCO") Transportation and Storage Capacity Contracts: EGMA has TETCO long-haul firm transportation capacity contracts that provide United States Gulf Coast and Appalachian supplies to its Brockton Division customers. EGMA also holds

[3] Eastern Gas Transmission and Storage Company (EGST) is the current owner of the former Dominion Transmission Inc. and operates the former DTI pipeline and storage facilities.

two market area storage contracts on the TETCO system and associated short-haul transportation capacity to the Brockton Division. Further, EGMA holds short-haul TETCO transportation capacity from EGTS storage to the Brockton Division. These legacy contracts provide much needed balancing flexibility and supply reliability.

- Enbridge Storage: The Company has two storage contracts with Enbridge Storage. The storage services are located at the Dawn Hub and provide a natural hedge against winter prices increases. The supply from these storage services can be delivered to EGMA's Brockton, Springfield and Lawrence Divisions.
- Portland Natural Gas ("PNGTS") Transportation Contracts: The Company has three firm transportation agreements with PNGTS, one of which delivers gas from an Enbridge storage contract and the other two that deliver supplies purchased at Dawn to the Company's Springfield and Lawrence Divisions.
- Repsol Energy North America Corporation ("Repsol"): The Company has two peaking supply contracts for firm seasonal deliveries of re-gasified LNG from Repsol's Canaport LNG terminal. These supplies are delivered to TGP capacity at Dracut, MA.
- Constellation LNG ("CLNG"): The Company has a peaking supply contract for firm season deliveries of re-gasified LNG from CLNG's Everett Marine Terminal delivered to its meters on the AGT G-lateral.
- Millennium Pipeline Company ("MPC"): The Company has one firm transportation agreement with MPC allowing for delivery of Marcellus basin supplies into AGT for delivery to the Company's Brockton Division.
- TransCanada Pipelines Limited (TCPL): The Company has three contracts that transport Canadian supply into PNGTS and IGT and eventually to AGT and TGP city gates.
- Transcontinental Gas Pipeline ("Transco") Transportation Capacity Contract: EGMA has one legacy contract on Transco that transports some of the EGTS storage volumes onto Algonquin for ultimate delivery to EGMA's Brockton Division.

- Granite State Gas Transmission, Inc.(GSGT): The Company has one firm transportation agreement that allows for delivery to a Northern Utilities city-gate as part of an Exchange Agreement. EGMA receives gas at Lawrence, Springfield and Brockton from Northern Utilities as reciprocation.

An important consideration in determining whether renewal of legacy contracts is consistent with a least-cost strategy is the cost of new capacity. During the past five to ten years, most new pipeline projects built have charged marginal-cost-based rates for the associated incremental pipeline capacity. Marginal-cost-based rates are higher than current legacy capacity[4] rates on the pipelines that serve EGMA. These legacy pipeline rates and associated capacity are advantaged by lower initial construction costs and significant depreciation of their plant and rate base, of which the revenue requirement is recovered by pipelines at average cost-based rates. These lower rates result in higher load factors and higher billing determinants, which in combination help to further maintain the lower rates associated with these legacy pipeline contracts. Further, because legacy transportation capacity is fully subscribed from the reliable, low-cost basins to the south and west, the only opportunity for the Company to replace these needed resources would be (a) from higher cost resources sourced from the north and east;[5] or (b) from supplies from traditional supply areas transported by higher cost, incremental facilities.

In the context of this report, EGMA has therefore reflected the renewal and continuation of all legacy capacity resources, for which the Company has a right-of-first refusal or a rollover right that comes up for renewal during the five-year planning horizon of the Plan. Given the current market dynamics where new capacity serving New England has become more costly and harder to obtain FERC approvals and general support new infrastructure, renewing legacy

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4 Legacy capacity is defined here as firm interstate pipeline transportation and storage service provided to EGMA and other New England LDCs under FERC-approved rate schedules, which were in effect upon or soon after the unbundling of the United States' interstate pipeline system resulting from FERC Order No. 636.

5 As noted hereinabove, the Company has executed agreements for capacity from TGP/PNGTS/TCPL/Union and Repsol. While these resources are generally more costly than the Company's traditional legacy contracts, the Company has exerted much effort to ensure access to highly reliable supplies as compared to the increasing uncertainty and volatility of prices for supplies procured at New England supply points, for example, Dracut, MA.

contracts helps ensure that the Company maintains competitively-priced services and supply diversity benefits for its customers.

In addition, rollover of the Company's other existing capacity with a right-of-first refusal or roll-over right has historically proven to be far more economical than procuring capacity on most of the new pipeline projects available to the Company. This valuable legacy capacity is expected to continue to be more economical in the future, and therefore, the Plan reflects these rollovers. The Company notes, however, that when making renewal, replacement, or incremental capacity decisions, it will employ the planning, supply and capacity acquisition methods approved under this Plan to further ensure that the decision-making process used is reasonable and appropriate, and that the decision is based on the best information available to EGMA at the time it is made.

EGMA's on-going evaluation of these resource strategies will be reflected in its Resource Action Plan in Section V ("Action Plan"). The Action Plan includes the results of EGMA's resource assessments and the factors that EGMA will evaluate in making its decisions to contract or de-contract for capacity in order to satisfy its obligation to meet firm customer demand and, in the process, ensure that each decision constitutes the best available alternative at the time it is made. All new supply and capacity contracts entered into by the Company for more than one year will be filed with the Department for approval, as required by law and Department precedent. The Company has identified in Table G-24, page 1, those contracts that expire within two years of this F&SP filing date.

III. 5- YEAR LOAD FORECAST

A. FORECAST METHODOLOGY

1. Methodology Overview

The primary objective of the demand forecast process is to determine Eversource Gas Company of Massachusetts' planning load forecast under normal and design weather conditions, and high and low growth scenarios. The Company uses these forecasts to assess the adequacy of its resource plans relative to the extreme weather and growth conditions.

The Company developed the Residential and C&I sales & transportation forecasts included here. The Company has prepared a base case planning load forecast, together with a number of planning load forecasts that reflect a range of weather and growth scenarios. The planning load forecast for the gas-supply planning years 2023/24 through 2027/28 (the "forecast period") is derived from forecast models that were developed for four customer segments. The weather-related scenarios that are applied to the forecast models include normal year and design year; the design year scenario includes the design winter, design day and cold snap standards. High growth and low growth scenarios were also performed.

Separate demand forecasts were developed for the Company's three divisions: Brockton, Lawrence, and Springfield. For each division, base case forecasts of quarterly demand for each customer segment were developed by applying normal weather data and data representing forecasted economic and demographic conditions to the forecast models; the economic and demographic variables in the forecast models were identified in the modeling process to be the major factors influencing natural gas demand in each of the Company's service territories. The Company's planning load forecast was determined by combining: (a) customer segment demand forecasts; (b) minus capacity exempt demand; (c) minus incremental savings expected from the Company's existing energy efficiency programs; and (d) plus adjustments for Company Use and losses. The process that was used to develop the 2023 Forecast and Supply Plan ("F&SP") demand forecast is further described in this Section III.A

This report uses the terms that are listed in Figure 1 to refer to and distinguish between different types of natural gas demand.

Figure 1: Forecast Terms

Term	Definition
Demand, Usage, Volume or Load	Generic terms that refer to the gas used by customers to meet their energy requirements.
Customer Segment Demand	Total firm sales plus total firm transportation demand (measured at the customer meter on a billing period basis) for a customer group, which is a defined group of rate classes.

Term	Definition
Throughput	Total gas sendout measured at Company gate stations and at Company LNG facilities on a calendar period basis; throughput also equals the sum of (a) sales plus total transportation gas use measured at customers' meter, (b) Company Use, and (c) losses and unaccounted for gas.
Capacity Exempt customers	Transportation customers that are not subject to the capacity assignment provisions as set forth in the Company's Distribution and Default Service Terms and Conditions, Section 13, M.D.P.U. No. 400D.
Non-Capacity Exempt customers	Transportation customers that are subject to the capacity assignment provisions as set forth in the Company's Distribution and Default Service Terms and Conditions, Section 13, M.D.P.U. No. 400D. These customers are also referred to as capacity eligible customers.
Planning Load	Total firm sales plus non-capacity exempt transportation usage measured at the gate station on a calendar period basis (i.e., includes Company Use, and losses) – excludes capacity exempt transportation load.

2. Summary of Normal Year Forecast Results

As determined in the forecast process that is described in Sections III.A and III.B, the Company's normal year planning load,[6] including the effects of expected future energy efficiency measures, is projected to increase at a 1.14% compound annual growth rate ("CAGR") from 2023/24 through 2027/28. Residential demand[7] is forecasted to increase at a 1.29% annual rate, and C&I demand[8] is forecasted to increase by 1.19% per year during the forecast period. The planning load forecast results are summarized in Figure 2 below.

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6 Includes all firm sales and firm transportation customer demand, Company Use, Lost and Unaccounted for Sales and the effects of Energy Efficiency programs; excludes all interruptible, and capacity exempt demand.

7 Includes Residential Heating and Residential Non-Heating customer segments.

8 Includes High Load Factor and Low Load Factor customer segments.

Figure 2: Normal Year Firm Planning Load Forecast Results Summary (Including Effects of Energy Efficiency) (MMBtu)[9,10]

EGMA Gas Total

Gas Year	Residential	C&I Sales plus Capacity Eligible Transportation	Energy Efficiency Adjustment	Company Use and Losses	Planning Load
2023/24	26,065,769	19,777,262	-93,493	1,132,410	46,881,949
2024/25	25,982,838	19,427,898	-144,054	1,124,588	46,391,270
2025/26	26,309,037	19,663,204	-194,834	1,134,748	46,912,155
2026/27	26,910,319	20,290,017	-245,905	1,156,970	48,111,401
2027/28	27,434,801	20,737,890	-296,652	1,174,564	49,050,603
CAGR	1.29%	1.19%	33.46%	0.92%	1.14%

B. CUSTOMER SEGMENT FORECAST MODELS

1. Development

The customer segment demand forecast was developed by preparing separate quarterly forecast models for the following four customer segments for the Company's three operating divisions, Brockton, Lawrence, and Springfield:

- Residential Heating
- Residential Non-Heating
- C&I Low Load Factor (LLF)
- C&I High Load Factor (HLF)

Separate econometric models were developed for the number of customers and use per customer for the residential heating and non-heating and C&I LLF and HLF customer segments.

Starting in the mid-1990s, EGMA has provided unbundled transportation to some C&I customers, who purchase gas directly from third party suppliers. To estimate firm transportation demand, the Company developed forecasts for (a) combined firm sales and firm transportation

9 The values in the Energy Efficiency Adjustment columns represent the EE savings impacts on Planning Load, i.e., net of Capacity Exempt ("CE") EE savings. Total EE savings are allocated between firm Sales, Non-capacity Exempt and CE load on a pro-rata basis.

10 Throughout this F&SP and the Appendices, gas quantities are reported as dekatherms ("Dth") and MMBtu; these two terms are identical units of measure, 1,000,000 British thermal units.

customer segments; and (b) firm sales only demand for the C&I customer segments. The firm transportation forecast is calculated as the difference between the firm sales and transportation forecast and the firm sales forecast. Non-capacity-exempt, i.e., capacity eligible, transportation demand was calculated by taking the ratio of capacity eligible volumes to total transportation volumes from the second quarter 2022 through the first quarter of 2023 and applying that ratio to the total forecast transportation demand.

The regression analyses were conducted using the EViews software package. Regression modeling techniques were used to develop the number of customers and use per customer based on variables such as weather, natural gas prices, and other economic and demographic variables. Each model was tested for autocorrelation, heteroskedasticity, instability, multicollinearity, and outliers. Models were corrected for any violations of standard assumptions of regression analysis that were identified by these tests. The modeling development process and specific statistical techniques are discussed in Appendix 3. The results of these tests are provided in Appendix 4.

Projected customer demand for this F&SP is derived from the forecast models and forecasts of future economic conditions in the region. The total demand for each residential and C&I customer segment for each quarter in the forecast period is calculated by multiplying the forecasted number of customers by the forecasted use per customer in that forecasted quarter. The Planning Load projections for each forecasted customer segment account for the portion of transportation-only throughput that is capacity eligible. Thus, the Company's resource planning accounts for the loads served by third-party suppliers for capacity exempt and capacity eligible transportation customers. Projected customer requirements are forecasted for the base case as well as for high and low load growth scenarios to ensure that the EGMA portfolio is adequate to meet its customer requirements under a range of potential future conditions.

Forecasts of Company Use and Lost and Unaccounted for gas were developed based on recent history and added to the customer segment forecast. Projected customer requirements also were adjusted for the impact of energy efficiency measures that are projected to be installed during the forecast period.

Lastly, EGMA determined its design planning standards based on a statistical analysis of historical weather data for each division. The design planning standards establish the design day, design winter and cold snap conditions that the EGMA resource portfolio must satisfy in order to ensure system safety, integrity and reliability.

2. Variable Descriptions

The first step in the demand forecasting process is the collection of various historical and projected data required to develop the forecast models. The forecast models used to derive the Company's five-year demand forecast rely on a number of internal and external data sources. Historical values of the dependent variables in these forecast models are obtained from EGMA billing data for customer counts and delivered volumes; use per customer values were calculated using the customer and volume billing data. Independent variables for the forecast models include measures for weather, demographic conditions, and economic conditions. Historical and projected values of the economic independent variables were obtained from Moody's Analytics. The general data and variable categories that were utilized in the development of the forecast are described in the following sections.

a) Customer Segment Data

The Company analyzed monthly billing data by customer class for the Brockton, Lawrence, and Springfield divisions for historical periods ending September 2022 (2022 Q3); the starting points for the statistical analyses vary. The EGMA customer class data was aggregated into the four customer segments, as shown in Figure 3 below.

Figure 3: Customer Segment Definitions

Rate Class	Customer Segment
R-1, R-2	Residential Non-Heating
R-3, R-4	Residential Heating Sales and Transportation
G-40, G-41, G-42, G-43	Low Load Factor
G-50, G-51, G-52, G-53	High Load Factor

The following is a summary of the process that was used to develop quarterly Customer Segment data:

- Company billing month customer, usage, and revenue data for each rate class was collected for the historical period beginning as early as January 2005 – depending on customer segment – through September 2022.

- The billing month rate class data was aggregated into Customer Segments as defined by the table above.
- The billing month Customer Segment data was aggregated into billing quarters to be used as dependent variables in the customer and use per customer quarterly forecast models.

b) Weather Variable

Effective Degree Days ("EDDs") were utilized as the weather measure. Daily U.S weather bureau data was purchased for the Company's three divisions. The data were used by the Company to calculate EDDs. EDDs are Heating Degree Days ("HDDs") adjusted for average daily wind speed.

The historical daily EDD data was converted to a billing quarter basis to be used in the quarterly forecast models. The process that was used to calculate the billing quarter EDD variable from daily EDD data is described in Appendix 5.

c) Natural Gas Price Variable

Because economic theory suggests that demand is likely to be influenced by price, a natural gas price variable was developed to be included in the customer segment models. Data to construct gas price variables were obtained from Company resources; historical data were obtained from Company billing records and price forecasts were developed using the process described in Appendix 6.

d) Economic and Demographic Variables

Economic theory suggests that demand may also be affected by other economic and demographic variables. To reflect economic and demographic conditions for EGMA operating divisions, the Company obtained historical metropolitan statistical area (MSA) data from Moody's Analytics for the period from 2005Q1 through 2022Q3 and forecasted data from 2022Q4 through 2032Q4. The MSAs in the Company's three divisions are shown in Figure 4 and the data series that were obtained from Moody's are shown in Figure 5.

Figure 4: Metropolitan Statistical Areas in EGMA Divisions

Statistical Areas
Providence-Warwick, RI-MA Boston-Cambridge-Newton, MA-NH Springfield, MA

Figure 5: Data Obtained from Moody's Analytics

Economic and Demographic Data
Employment (NAICS), Total Nonfarm Employment (NAICS), Manufacturing Average Personal Income per Household Real Per Capita Income Gross Metro Product Number of Households Housing Completions Population
Prices
Henry Hub market price of natural gas, $/MMBtu U.S. No. 2 Diesel Retail Sales by All Sellers, $/Gallon
Price Deflators
Consumer Price Index, All Urban Consumers

e) Dependent Variables

The dependent variable data for the customer and use per customer ("UPC") customer segment models were derived from Company billing records. Billing month[11] rate class customer count and billing data were aggregated into quarters and also aggregated into the four customer segments that are shown in Figure 3. The dependent variables that were used to develop the F&SP forecast models are listed in Appendix 7; graphical summaries of the dependent variable data are provided in Appendix 8.

[11] An explanation of the process of converting calendar EDDs to billing period EDDs can be found in Appendix 5.

f) Other Variables

The following additional variables were created to be used in the development of the customer segment models:

- Trend variables were created to represent changes in the number of customers or use per customer that were a function of time.
- Binary variables (or dummy variables) were created to represent time-related events.[12]
- Interaction terms related to certain binary variables were created to represent changes in the relationships between the dependent variable and independent variables as a result of time-related events.

C. CUSTOMER SEGMENT MODEL RESULTS

1. Introduction

The following sections summarize each customer segment model and the model forecast results. As explained in Appendix 3, each model was tested for the presence of autocorrelation, heteroskedasticity, multicollinearity, stability, and outliers, and appropriate modifications were made to the models based on the test results. An ex post analysis was performed for each model and the model specification was modified if necessary. Detailed statistical results for each customer segment model are provided in Appendix 4. In addition to the model statistics and the results of the tests for autocorrelation, heteroskedasticity, multicollinearity, stability and outliers, Appendix 4 includes explanations for any dummy variables that were used in a forecast model.

2. Residential Heating Customer Segment

The Residential Heating customer segment represented 85.2% of total customers and 50% of total actual demand in 2022. From 2019 to 2022, the number of Residential Heating customers increased by 1.5% per year, and weather normalized Residential Heating customer demand increased by 0.5% per year.

a) Residential Heating Customer Model Results

Economic theory suggests that the number of Residential Heating customers may be dependent on such variables as a measure of the number of people living in the service territory

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[12] These binary variables equal 1 when a specific time-related event occurs, and equal 0 outside of that specific time.

(e.g., households or population); measures of income or wealth; and measures that reflect the competitiveness of natural gas relative to other energy types. In addition, the number of Residential Heating customers in a quarter reflects a seasonal pattern; generally, the greatest number of Residential Heating customers take service from a typical New England gas distribution company in Quarter 1, and the fewest number of Residential Heating customers take service in Quarter 3.

The Final EGMA Residential Heating customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

*Total customer count = (a) + (b)*Economic Variable + + (c)*Quarterly Variables + (d)*Price Variable + (e)*Binary Variables + (f)*Interaction Variables*

The economic drivers in the Residential Heating customer models for Lawrence and Springfield are cumulative housing counts and Brockton's is personal income. The variable coefficients and the binary and interaction variables that are included in the Residential Heating Customer models are listed and supporting explanations for the variables are provided in Appendix 4.

Over the forecast period, the number of Residential Heating customers is projected to grow at an annual rate of 1.27%, as shown by Figure 6 below.

Figure 6: Residential Heating Customer Model Forecast[13]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	145,766	46,774	92,922	285,463
2024/25	147,969	47,365	93,716	289,050
2025/26	150,086	47,998	94,588	292,672
2026/27	152,255	48,707	95,543	296,505
2027/28	154,278	49,456	96,527	300,261
CAGR	1.43%	1.40%	0.96%	1.27%

[13] Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

b) Residential Heating Use per Customer Model Results

Economic theory suggests that use per customer in the Residential Heating customer segment may be dependent on such variables as weather, price, income, wealth, household size, and efforts to conserve.

The Final Residential Heating use per customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Use per Customer} = (a) + (b)*\textit{Effective Degree Days} + (c)*\textit{Price} + (d_i)*\textit{Binary Variables}_i + (e_i)*\textit{Interaction Variables}_i$$

Residential Gas Price and weather are the major drivers in the Residential Heating use per customer models in all three territories. The variable coefficients and the binary and interaction variables that are included in the models are listed and supporting explanations for the variables are provided in Appendix 4.

Over the forecast period, the weighted average use per customer for the Residential Heating segment is projected to remain steady with 0.0% growth per year, as shown in Figure 7 below.

Figure 7: Residential Heating Use per Customer Model Forecast (MMBtu/Customer – Normal Year)[14]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	91.7	102.0	83.5	277.1
2024/25	89.9	100.9	82.6	273.4
2025/26	89.8	100.6	82.6	273.1
2026/27	91.1	101.1	83.2	275.4
2027/28	91.9	101.5	83.7	277.1
CAGR	0.06%	-0.11%	0.06%	0.00%

[14] Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

c) Residential Heating Demand Results

The Residential Heating demand forecast was calculated by multiplying the forecasted number of Residential Heating customers for each quarter by the forecasted Residential Heating use per customer for that quarter. Over the forecast period, total Residential Heating demand is projected to increase by 1.13% per year, as shown in Figure 8A below, and the Residential Heating segment planning load is projected to increase by 1.15% per year, as shown in Figure 8B.

Figure 8A: Residential Heating Demand Forecast (MMBtu – Normal Year)[15, 16]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	13,479,139	4,812,536	7,875,443	26,167,117
2024/25	13,374,970	4,814,710	7,842,921	26,032,601
2025/26	13,547,502	4,857,261	7,911,646	26,316,408
2026/27	13,907,840	4,941,085	8,031,446	26,880,370
2027/28	14,199,075	5,031,455	8,144,173	27,374,703
CAGR	1.31%	1.12%	0.84%	1.13%

Figure 8B: Residential Heating Planning Load Forecast (MMBtu – Normal Year)[17,18]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	13,472,610	4,813,363	7,874,927	26,160,900
2024/25	13,379,155	4,816,097	7,845,075	26,040,327
2025/26	13,556,892	4,858,784	7,914,140	26,329,817
2026/27	13,918,249	4,943,845	8,034,691	26,896,784
2027/28	14,206,978	5,034,012	8,146,944	27,387,934
CAGR	1.34%	1.13%	0.85%	1.15%

15 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13.

16 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

17 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13

18 The planning load results summarized in this table are net of unbilled adjustments, and on a gas year basis that corresponds to Nov-Oct (i.e., the twelve months from November through the following October).

3. Residential Non-Heating Customer Segment

Residential Non-Heating was the smallest EGMA customer segment in terms of demand for all three divisions in 2022. The Residential Non-Heating customer segment represented 5.3% of total customers and 0.7% of total actual demand in 2022. From 2019 to 2022, the number of Residential Non-Heating customers decreased by 2.6% per year, and weather normalized Residential Non-Heating customer demand decreased by 0.1% per year.

a) Residential Non-Heating Customer Model Results

Economic theory suggests that the number of Residential Non-Heating customers may be dependent on such variables as a measure of the number of people living in the service territory (e.g., households or population); measures of income or wealth; a trend variable to represent the decline in the number of non-heating customers;[19] and measures that reflect the competitiveness of natural gas relative to other energy types.

The EGMA Residential Non-Heating customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Total customer count} = (a) + (b)*\textit{Trend} + (c_i)*\textit{Binary Variables}_i + (d_i)*\textit{Interaction Variables}_i$$

A quarterly trend was the significant driver in the Residential Non-Heat Customer models for all three divisions. The variable coefficients and the binary and interaction variables that are included in the Residential Non-Heating Customer models are listed and supporting explanations for the variables are provided in Appendix 4.

Over the forecast period, the number of Residential Non-Heating customers is projected to decline at an annual rate of 3.59%, as shown by Figure 9 below.

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[19] The steady decline in the number of Residential Non-Heating customers is the result of these customers converting from oil to gas heating. Measures that captured the relative competitiveness of oil and gas prices were tested in the Residential Non-Heating models to explain the decline in non-heating customers. However, a trend variable was used because no statistically significant economic or price-based variable could be identified.

Figure 9: Residential Non-Heating Customer Model Forecast[20]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	6,603	2,038	7,927	16,568
2024/25	6,386	1,963	7,655	16,005
2025/26	6,170	1,888	7,384	15,441
2026/27	5,953	1,813	7,112	14,878
2027/28	5,736	1,738	6,840	14,315
CAGR	-3.46%	-3.90%	-3.62%	-3.59%

b) Residential Non-Heating Use per Customer Model Results

Economic theory suggests that use per customer in the Residential Non-Heating customer segment may be dependent on such variables as weather, price, income, wealth, household size and efforts to conserve.

The EGMA Non-Residential Heating use per customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

*Use per Customer = (a) + (b)*Effective Degree Days +* (c_i)**Binary Variables*$_i$ *+*
(d_i)**Interaction Variables*$_i$

The major driver of the Residential Non-Heat Use per Customer models in all three divisions was weather and the real price of non-heating gas. The variable coefficients and the binary and interaction variables that are included in the models are listed and supporting explanations for the variables are provided in Appendix 4.

20 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Over the forecast period, the average use per customer for the Residential Non-Heating segment is projected to increase by 0.32% per year, as shown in Figure 10 below.

Figure 10: Residential Non-Heating Use per Customer Model Forecast (MMBtu/Customer – Normal Year)[21]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	16.0	19.8	16.6	52.4
2024/25	15.4	19.7	16.5	51.6
2025/26	15.5	19.9	16.6	51.9
2026/27	15.9	19.9	16.7	52.6
2027/28	16.2	20.0	16.8	53.0
CAGR	0.41%	0.26%	0.31%	0.32%

c) Residential Non-Heating Demand Results

The Residential Non-Heating demand forecast was calculated by multiplying the forecasted number of Residential Non-Heating customers for each quarter by the forecasted Residential Non-Heating use per customer for that quarter. Over the forecast period, the total demand from the Residential Non-Heating segment total demand is projected to decrease by 3.41% per year, as shown in Figure 11A, and the Residential Non-Heating segment planning load is projected to decrease by 3.38% per year as shown in Figure 11 B.

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21 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Figure 11A: Residential Non-Heating Demand Forecast (MMBtu – Normal Year)[22, 23]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	108,078	41,093	135,075	284,246
2024/25	100,603	39,390	129,451	269,445
2025/26	97,360	38,165	125,486	261,012
2026/27	96,781	36,719	121,804	255,303
2027/28	94,706	35,213	117,523	247,442
CAGR	-3.25%	-3.79%	-3.42%	-3.41%

Figure 11B: Residential Non-Heating Planning Load Forecast (MMBtu – Normal Year)[24, 25]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	107,377	40,933	134,715	283,025
2024/25	100,194	39,298	129,114	268,606
2025/26	97,285	38,021	125,131	260,436
2026/27	96,590	36,574	121,396	254,560
2027/28	94,453	35,074	117,108	246,635
CAGR	-3.16%	-3.79%	-3.44%	-3.38%

4. Low Load Factor Customer Segment[26]

The Low Load Factor customer segment represented 7.8% of total customers and 30% of total actual demand in 2022. From 2019 to 2022, the number of Low Load Factor customers

22 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13.

23 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

24 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13

25 The planning load results summarized in this table are net of unbilled adjustments, and on a gas year basis that corresponds to Nov-Oct (i.e., the twelve months from November through the following October).

26 Includes both low load factor default sales and low load factor transportation customers.

increased by 0.1% per year, and weather normalized Low Load Factor customer demand decreased by 0.5% per year.

a) Low Load Factor Customer Model Results

Economic theory suggests that the number of Low Load Factor customers may be dependent on such variables as a measure of the economy in the service territory (e.g., gross metro product and/or non-manufacturing employment); and measures that reflect the competitiveness of natural gas relative to other energy types.

The EGMA Low Load Factor customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Total customer count} = (a) + (b)^{*}\textit{Economic Variable} + (c_i)^{*}\textit{Quarterly Variables}_i + (d)^{*}\textit{Price Variable} + (e_i)^{*}\textit{Binary Variables} + (f_i)^{*}\textit{Interaction Variables}_i$$

The economic driver in the Low Load Factor customer models in Brockton and Springfield is gross metro product, while the Lawrence model utilizes a price variable. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the Low Load Factor Customer models are provided in Appendix 4. Over the forecast period, the number of Low Load Factor customers is projected to grow at an annual rate of 0.62%, as shown by Figure 12 below.

Figure 12: Low Load Factor Customer Model Forecast[27]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	15,295	2,744	8,390	26,429
2024/25	15,389	2,599	8,433	26,421
2025/26	15,503	2,623	8,479	26,606
2026/27	15,624	2,726	8,523	26,873
2027/28	15,744	2,783	8,567	27,094
CAGR	0.73%	0.35%	0.52%	0.62%

[27] Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

b) Low Load Factor Use per Customer Model Results

Economic theory suggests that use per customer in the Low Load Factor customer segment may be dependent on such variables as weather, price, and/or efforts to conserve.

The EGMA Low Load Factor use per customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Use per Customer} = (a) + (b)*\textit{Effective Degree Days} + (c)*\textit{ Price} + (d_i)*\textit{Quarterly Variables}_i + (e_i)*\textit{Binary Variables}_i + (f_i)*\textit{Interaction Variables}_i$$

Weather and low load factor price variables are the drivers in all three divisions. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the models are provided in Appendix 4.

Over the forecast period, the weighted average use per customer for the Low Load Factor segment is projected to increase by 0.04% per year, as shown in Figure 13 below.

Figure 13: Low Load Factor Use per Customer Model Forecast (MMBtu/Customer – Normal Year)[28]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	506.9	782.3	665.9	1,955.1
2024/25	501.9	781.2	661.6	1,944.8
2025/26	500.4	781.4	665.8	1,947.6
2026/27	504.3	782.2	667.6	1,954.1
2027/28	506.5	782.6	668.8	1,957.9
CAGR	-0.02%	0.01%	0.11%	0.04%

c) Low Load Factor Demand Results

The Low Load Factor demand forecast was calculated by multiplying the forecasted number of Low Load Factor customers for each quarter by the forecasted Low Load Factor use per customer for that quarter. Total demand includes load from all sales and transportation customers, while planning load is total demand minus capacity exempt load. Over the forecast

[28] Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

period, the total demand from the Low Load Factor segment is projected to increase by 1.05% per year, as shown in Figure 14A, and the Low Load Factor planning load is projected to increase by 1.06% per year, as shown in Figure 14B.

Figure 14A: Low Load Factor Demand Forecast (MMBtu – Normal Year)[29, 30]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	7,051,591	1,980,818	4,387,196	13,419,606
2024/25	7,040,704	1,888,792	4,420,903	13,350,399
2025/26	7,111,988	1,886,027	4,502,519	13,500,534
2026/27	7,251,466	1,964,369	4,564,741	13,780,576
2027/28	7,360,442	2,008,923	4,621,124	13,990,489
CAGR	1.08%	0.35%	1.31%	1.05%

Figure 14B: Low Load Factor Planning Load Forecast (MMBtu – Normal Year)[31, 32]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	7,051,912	1,978,420	4,388,468	13,418,800
2024/25	7,042,205	1,887,649	4,424,440	13,354,294
2025/26	7,115,710	1,888,415	4,503,977	13,508,102
2026/27	7,254,380	1,965,601	4,566,139	13,786,120
2027/28	7,363,109	2,009,757	4,622,739	13,995,606
CAGR	1.09%	0.39%	1.31%	1.06%

29 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13.

30 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

31 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13

32 The planning load results summarized in this table are net of unbilled adjustments, without capacity exempt volumes, and on a gas year basis that corresponds to Nov-Oct (i.e., the twelve months from November through the following October).

5. **High Load Factor Customer Segment**[33]

The High Load Factor customer segment represented 1.6% of total customers and 19.6% of total actual demand in 2022. From 2019 to 2022, the number of High Load Factor customers increase by 2.5% per year, and weather normalized High Load Factor customer demand decreased by 1.5% per year.

a) High Load Factor Customer Model Results

Economic theory suggests that the number of High Load Factor customers may be dependent on such variables as a measure of the economy in the service territory (e.g., gross metro product and/or manufacturing employment) and measures that reflect the competitiveness of natural gas relative to other energy types.

The EGMA High Load Factor customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

Total customer count= (a) + (b) Price Variable + (c)*Economic Variable + (d_i)*Binary Variables$_i$ + (e_i)*Interaction Variables*

The economic driver in the High Load Factor customer models in all territories is natural gas prices. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the High Load Factor Customer models are provided in Appendix 4.

Over the forecast period, the number of High Load Factor customers is projected to remain steady at a compound annual growth rate of 0.01%, as shown by Figure 15 below.

33 Includes both high load factor default sales and high load factor transportation customers.

Figure 15: High Load Factor Customer Model Forecast[34]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	2,648	730	1,758	5,136
2024/25	2,477	728	1,754	4,959
2025/26	2,445	726	1,750	4,921
2026/27	2,578	727	1,752	5,058
2027/28	2,653	729	1,755	5,137
CAGR	0.05%	-0.04%	-0.05%	0.01%

b) High Load Factor Use per Customer Model Results

Economic theory suggests that use per customer in the High Load Factor customer segment may be dependent on such variables as weather, price, and / or efforts to conserve.

The Final NSTAR Gas High Load Factor use per customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Use per Customer} = (a) + (b)*\textit{Effective Degree Days} + (c)*\textit{Price} + (d)*\textit{Economic Variable} + (e_i)*\textit{Quarterly Variables} + (f_i)*\textit{Binary Variables}_i + (g_i)*\textit{Interaction Variables}_i$$

The price variable and weather variables are the drivers of High Load Factor use per customer in all three territories. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the models are provided in Appendix 4.

Over the forecast period, the use per customer for the High Load Factor segment is projected to increase by 0.09% per year, as shown in Figure 16 below.

34 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Figure 16: High Load Factor Use per Customer Model Forecast (MMBtu/Customer – Normal Year)[35]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	1,502.2	1,871.6	2,833.8	6,207.7
2024/25	1,460.4	1,828.9	2,817.2	6,106.5
2025/26	1,472.4	1,841.2	2,804.2	6,117.7
2026/27	1,502.2	1,871.6	2,813.2	6,187.1
2027/28	1,518.6	1,888.4	2,822.2	6,229.2
CAGR	0.27%	0.22%	-0.10%	0.09%

c) High Load Factor Demand Results

The High Load Factor demand forecast was calculated by multiplying the forecasted number of High Load Factor customers for each quarter by the forecasted High Load Factor use per customer for that quarter. Total demand includes load from all sales and transportation customers, while planning load is total demand minus capacity exempt load. Over the forecast period, the total demand from the High Load Factor segment is projected to increase by 1.29% per year, as shown in Figure 17A below, and the High Load Factor planning load is projected to increase by 1.46% per year, as shown in Figure 17B.

Figure 17A: High Load Factor Demand Forecast (MMBtu – Normal Year)[36, 37]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	3,622,931	1,015,973	2,107,555	6,746,458
2024/25	3,319,178	992,364	2,132,617	6,444,160
2025/26	3,286,847	1,004,420	2,185,627	6,476,894
2026/27	3,540,121	1,034,753	2,271,849	6,846,722
2027/28	3,689,843	1,056,701	2,354,008	7,100,552
CAGR	0.46%	0.99%	2.80%	1.29%

35 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

36 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13.

37 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Figure 17B: High Load Factor Planning Load Forecast (MMBtu – Normal Year)[38, 39]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	3,592,945	1,013,803	2,109,575	6,716,323
2024/25	3,296,815	991,923	2,136,405	6,425,143
2025/26	3,312,554	1,006,867	2,191,478	6,510,900
2026/27	3,555,665	1,036,551	2,278,820	6,871,036
2027/28	3,699,553	1,058,004	2,359,970	7,117,527
CAGR	0.73%	1.07%	2.84%	1.46%

6. Transportation Forecasts

The Company offers transportation service in accordance with the Department's directives in D.T.E. 98-32-B (1999). Transportation customer and volume forecasts for the C&I customer segments have been calculated by subtracting C&I sales customer and volume forecasts from C&I total sales and transportation customer and volume forecasts. As described in the following sections, sales customer and use per customer models were developed for all divisions for C&I Low Load Factor and C&I High Load Factor customer segments.

7. Low Load Factor Firm Sales Customer Segment

The Low Load Factor Firm Sales customer segment represented 85.2% of total Low Load Factor customers and 47.4% of total actual Low Load Factor demand in 2022. From 2019 to 2022, the number of Low Load Factor Firm Sales customers increased by 0.5% per year, and weather normalized Low Load Factor Firm Sales customer demand decreased by 0.9% per year.

a) Low Load Factor Firm Sales Customer Model Results

Economic theory suggests that the number of Low Load Factor Firm Sales customers may be dependent on such variables as a measure of the economy in the service territory (e.g., Gross

38 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13

39 The planning load results summarized in this table are net of unbilled adjustments, without capacity exempt volumes, and on a gas year basis that corresponds to Nov-Oct (i.e., the twelve months from November through the following October).

Metro Product and/or personal income) and/or measures that reflect the competitiveness of natural gas relative to other energy types. Over time, the number of Low Load Factor customers that have switched from bundled sales service to transportation service depends on the number and type of competitive suppliers that are working to attract new customers in the Company's service territory. Therefore, consumer behavior theory suggests that the number of sales customers may be dependent on non-economic and difficult-to-measure factors that are related to Low Load Factor customers' awareness of competitive choice and understanding of the benefits and risks of unbundled transportation service from EGMA coupled with supply service from competitive suppliers.

The EGMA Low Load Factor Firm Sales customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Total Customer Count} = (a) + (b)*\textit{Economic Variable} + (c_i)*\textit{Quarterly Variables} + (d)*\textit{Binary Variables}_i + (e_i)*\textit{Interaction Variables}$$

Gross Metro Product is an economic driver in Springfield and Brockton, while personal income and price are the drivers in Lawrence. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the Low Load Factor Firm Sales Customer models are provided in Appendix 4.

Over the forecast period, the number of Low Load Factor Firm Sales customers is projected to grow at an annual rate of 0.78%, as shown by Figure 18 below.

Figure 18: Low Load Factor Firm Sales Customer Model Forecast[40]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	13,171	2,520	6,917	22,609
2024/25	13,291	2,513	6,954	22,757
2025/26	13,416	2,534	6,992	22,942
2026/27	13,536	2,569	7,029	23,133
2027/28	13,660	2,595	7,067	23,322
CAGR	0.91%	0.74%	0.53%	0.78%

40 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

b) Low Load Factor Firm Sales Use per Customer Model Results

Economic theory suggests that use per customer in the Low Load Factor Firm Sales customer segment may be dependent on such variables as weather, price, and/or efforts to conserve.

The EGMA Low Load Factor Firm Sales use per customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Use per Customer} = (a) + (b)\text{*}\textit{Effective Degree Days} + (c)\text{*}\textit{Price Variable} + (d)\text{*}\textit{Economic Variable} + (e_i)\text{*}\textit{Quarterly Variables}_i + (f_i)\text{*}\textit{Binary Variables}_i + (g_i)\text{*}\textit{Interaction Variables}_i$$

Weather and price are the drivers of Low Load Factor Sales use per customer in all three divisions. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the models are provided in Appendix 4.

Over the forecast period, the average use per customer for the Low Load Factor Firm Sales segment is projected to increase with a compound annual growth rate of 0.35%, as shown in Figure 19 below.

Figure 19: Low Load Factor Firm Sales Use per Customer Model Forecast (MMBtu/Customer – Normal Year)[41]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	313	452	314	1,078.7
2024/25	307	454	317	1,077.3
2025/26	311	454	318	1,083.5
2026/27	316	455	319	1,089.9
2027/28	319	455	319	1,093.8
CAGR	0.53%	0.19%	0.40%	0.35%

[41] Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

c) Low Load Factor Firm Sales Demand Results

The Low Load Factor Firm Sales demand forecast was calculated by multiplying the forecasted number of Low Load Factor Firm Sales customers for each quarter by the forecasted Low Load Factor Firm Sales use per customer for that quarter. Over the forecast period, the total demand from the Low Load Factor Sales segment is projected to increase by 1.22% per year, as shown in Figure 20A below, and the Low Load Factor Sales planning load is projected to increase by 1.23% per year, as shown in Figure 20B.

Figure 20A: Low Load Factor Sales Demand Forecast (MMBtu – Normal Year)[42, 43]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	4,190,738	1,158,568	2,214,432	7,563,738
2024/25	4,149,379	1,158,962	2,245,243	7,553,584
2025/26	4,245,761	1,170,219	2,268,985	7,684,965
2026/27	4,357,310	1,187,965	2,285,730	7,831,005
2027/28	4,437,719	1,201,569	2,301,301	7,940,590
CAGR	1.44%	0.92%	0.97%	1.22%

[42] All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13.

[43] Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Figure 20B: Low Load Factor Sales Planning Load Forecast (MMBtu – Normal Year)[44, 45]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	4,188,740	1,158,840	2,216,020	7,563,599
2024/25	4,151,345	1,159,314	2,246,349	7,557,008
2025/26	4,249,055	1,170,535	2,269,071	7,688,661
2026/27	4,359,640	1,188,242	2,285,868	7,833,750
2027/28	4,439,611	1,201,789	2,301,542	7,942,942
CAGR	1.46%	0.91%	0.95%	1.23%

8. High Load Factor Firm Sales Customer Segment

The High Load Factor Firm Sales customer segment represented 77.5% of total High Load Factor customers and 26.6% of total High Load Factor actual demand in 2022. From 2019 to 2022, the number of High Load Factor Firm Sales customers increased by 2.6% per year, and weather normalized High Load Factor Firm Sales customer demand decreased by 0.8% per year.

a) High Load Factor Firm Sales Customer Model Results

Economic theory suggests that the number of High Load Factor Firm Sales customers may be dependent on such variables as a measure of the economy in the service territory (e.g., Gross Metro Product and/or manufacturing employment) and/or measures that reflect the competitiveness of natural gas relative to other energy types. Over time, the number of High Load Factor customers that have switched from bundled sales service to transportation service depends on the number and type of competitive suppliers that are working to attract new customers in EGMA's service territory. Therefore, consumer behavior theory suggests that the number of sales customers may be dependent on non-economic and difficult-to-measure factors that are related to High Load Factor customers' awareness of competitive choice and understanding of the benefits

44 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13

45 The planning load results summarized in this table are net of unbilled adjustments, without capacity exempt volumes, and on a gas year basis that corresponds to Nov-Oct (i.e., the twelve months from November through the following October).

and risks of unbundled transportation service from EGMA coupled with supply service from competitive suppliers.

The EGMA High Load Factor Firm Sales customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$Total\ Customer\ Count = (a) + (b)*Economic\ Variable + (c)*\ Price\ Variable + (d_i)*Binary\ Variables_i + (e_i)*Interaction\ Variables$$

Natural gas prices are the main drivers in all territories for High Load Factor Customer models. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the High Load Factor Firm Sales Customer models are provided in Appendix 4.

Over the forecast period, the total number of High Load Factor Firm Sales customers is projected to increase by 0.23%, as shown by Figure 21 below.

Figure 21: High Load Factor Firm Sales Customer Model Forecast[46]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	2,197	573	1,366	4,137
2024/25	2,188	566	1,357	4,111
2025/26	2,203	569	1,359	4,130
2026/27	2,217	576	1,365	4,158
2027/28	2,225	580	1,369	4,174
CAGR	0.31%	0.29%	0.05%	0.23%

b) High Load Factor Firm Sales Use per Customer Model Results

Economic theory suggests that use per customer in the High Load Factor Firm Sales customer segment may be dependent on such variables as weather, price, and efforts to conserve.

The EGMA High Load Factor Firm Sales use per customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$Use\ per\ Customer = (a) + (b)*Effective\ Degree\ Days + (c)*Price\ Variable + (d_i)*Quarterly\ Variables_i + (e_i)*Binary\ Variables_i + (f_i)*Interaction\ Variables$$

46 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Weather and price are the main drivers of High Load Factor Sales use per customer in all three divisions. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the models are provided in Appendix 4.

Over the forecast period, the use per customer for the High Load Factor Firm Sales segment is projected to decrease by 0.16%, as shown in Figure 22 below.

Figure 22: High Load Factor Firm Sales Use per Customer Model Forecast (MMBtu/Customer – Normal Year)[47]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	707.9	658.0	588.4	1,954.3
2024/25	675.4	614.7	559.8	1,849.9
2025/26	673.0	611.5	556.5	1,841.0
2026/27	691.4	635.2	572.7	1,899.3
2027/28	704.4	652.9	584.3	1,941.6
CAGR	-0.12%	-0.19%	-0.18%	-0.16%

c) High Load Factor Firm Sales Demand Results

The High Load Factor Firm Sales demand forecast was calculated by multiplying the forecasted number of High Load Factor Firm Sales customers for each quarter by the forecasted High Load Factor Firm Sales use per customer for that quarter. Over the forecast period, the total demand from the High Load Factor Sales segment is projected to increase by 0.03% per year, as shown in Figure 23A below, and the High Load Factor Sales planning load is projected to increase by 0.22% per year, as shown in Figure 23B.

47 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Figure 23A: High Load Factor Sales Demand Forecast (MMBtu – Normal Year)[48, 49]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	1,593,798	386,034	824,825	2,804,657
2024/25	1,512,323	355,240	779,308	2,646,871
2025/26	1,515,815	354,557	774,598	2,644,969
2026/27	1,567,147	372,751	800,453	2,740,351
2027/28	1,602,687	386,116	819,112	2,807,914
CAGR	0.14%	0.01%	-0.17%	0.03%

Figure 23B: High Load Factor Sales Planning Load Forecast (MMBtu – Normal Year)[50,51]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	1,584,294	382,671	819,701	2,786,666
2024/25	1,509,877	354,297	777,410	2,641,584
2025/26	1,519,749	355,946	776,393	2,652,088
2026/27	1,570,656	374,035	802,335	2,747,025
2027/28	1,604,512	386,832	820,066	2,811,410
CAGR	0.32%	0.27%	0.01%	0.22%

9. Capacity-Eligible Transportation Load

The Company's Distribution and Default Service Terms and Conditions provide for the assignment of a share of all EGMA gas resource contracts that are eligible for assignment to

48 All Customer Segment forecast results are before adjustments for EE savings, which will be discussed in Section III.C.13.

49 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

50 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13

51 The planning load results summarized in this table are net of unbilled adjustments, without capacity exempt volumes, and on a gas year basis that corresponds to Nov-Oct (i.e., the twelve months from November through the following October).

customers that received bundled sales service after February 1, 1999.[52] All other customers that (a) received bundled sales service at some time but converted to unbundled transportation service prior to February 1, 1999 or (b) have never received bundled sales service, are "Capacity Exempt" transportation customers. The Company must have adequate resources to meet the projected demands of bundled sales customers and non-capacity exempt customers; as directed by the Department, EGMA does not plan its resources to meet the projected demand of capacity exempt customers[53]. Due to ongoing constraints on discrete supply availability for portions of its system (i.e. AGT G Lateral), the Company is including the supplies needed to meet both its planning and capacity exempt customers demand in these locales and will be filing tariff revisions to effectuate these needs to preserve the supply availability and the subsequent cost allocations per D.P.U. 21-09.

In terms of resource planning, one of the components of the Company's total load that must be accounted for is capacity eligible firm transportation load; capacity eligible load is that portion of the Company's firm transportation load that is subject to mandatory capacity assignment as specified in the Company's Distribution Terms and Conditions, Section 13.0.

For each of the three divisions, Brockton, Lawrence and Springfield, statistical models were used to derive (a) forecast total firm sales and transportation load and (b) forecast firm sales load. Total forecast firm transportation load was derived by subtracting forecast firm sales demand from forecast total firm sales and transportation demand. This forecast firm transportation demand consists of (a) capacity eligible firm transportation demand and (b) capacity exempt demand.

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[52] EGMA customers that were taking firm transportation service prior to February 1, 1999 were "grandfathered" and were therefore exempt from the provisions of the Company's capacity assignment requirements.

[53] In D.P.U. 14-111, the Department authorized LDCs to plan for up to 30% of their capacity exempt customers to convert from capacity exempt status to default sales/capacity eligible status for the winter of 2014-15 and in D.P.U. 15-43, the Department allowed the LDCs to plan for the conversion of up to 30% of the remaining capacity exempt customers to convert. Under Department policies, once a customer converts from capacity exempt to default sales, they become part of the Company's planning load. In D.P.U. 15-43, the Department also instructed each LDC to include in their long range Forecasts and Supply Plans a forecast of subsequent conversions from capacity exempt to default sales/capacity eligible status. The current forecast includes the loads that have returned to default sales/capacity eligible status pursuant to the Department's decisions in D.P.U. 14-111 and to D.P.U. 15-43.

The forecast of capacity eligible transportation demand is calculated by multiplying (a) capacity eligible factors, by division and customer type, which EGMA derived based on four years of historical data, times (b) total forecast C&I transportation demand, by division and customer type. Forecast capacity exempt transportation demand is the difference between forecast transportation demand and forecast capacity eligible demand. The capacity eligible factors were calculated as the ratio of quarterly capacity eligible transportation demand divided by total transportation demand using data from 2022Q2 through 2023 Q1.

The resulting percentages by division and customer type were used to forecast capacity eligible transportation over the forecast period. To illustrate the recent trend of conversions, historical data for the period 2019Q1 through 2022Q4 is shown in Figure 24.

Figure 24: Capacity Eligible C&I Transportation as a fraction of Total C&I Transportation Demand

Capacity Eligible Ratio				
Year	Quarter	Brockton	Lawrence	Springfield
2019	1	24%	36%	51%
2019	2	26%	33%	58%
2019	3	30%	32%	71%
2019	4	27%	30%	58%
2020	1	22%	28%	51%
2020	2	25%	32%	53%
2020	3	30%	40%	70%
2020	4	28%	36%	59%
2021	1	23%	31%	50%
2021	2	25%	33%	61%
2021	3	23%	41%	69%
2021	4	24%	36%	58%
2022	1	19%	28%	50%
2022	2	21%	30%	61%
2022	3	23%	36%	70%
2022	4	23%	31%	58%

Over the forecast period, the Capacity Eligible load is projected to increase at an annual rate of 1.44%, as shown by Figure 25 below.

Figure 25: Capacity Eligible C&I Transportation Demand (MMBtu – Normal Year)[54]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	4,871,823	1,450,713	3,462,322	9,784,858
2024/25	4,677,797	1,365,961	3,537,086	9,580,844
2025/26	4,659,460	1,368,801	3,649,992	9,678,253
2026/27	4,879,749	1,439,876	3,756,756	10,076,382
2027/28	5,018,540	1,479,140	3,861,102	10,358,781
CAGR	0.74%	0.49%	2.76%	1.44%

10. Company Use Forecast

Company Use gas is (a) metered gas usage for space heating at Company buildings and (b) metered gas used in the production of gas at Company LNG facilities. Consistent with its prior approved filings, EGMA determined that average company use values by quarter, using data from 2013Q1 through 2022Q4, were most representative of forecast Company Use through the Forecast Period. See Appendix 10 and Figure 26.

Figure 26: Company Use Forecast (MMBtu – Normal Year)

Gas Year	Company Use
2023/24	302,900
2024/25	302,900
2025/26	302,900
2026/27	302,900
2027/28	302,900
CAGR	0.00%

11. Forecast of Lost and Unaccounted For Gas

Lost and Unaccounted for gas ("LAUF") is the difference between (1) the gas that is added into the distribution system (a) at interconnection points between interstate pipelines and the

54 Volumes are calendar period basis.

distribution system or (b) from locally-produced gas at LNG facilities; and (2) gas that is withdrawn from the distribution system to be used by the LDC's customers.[55]

To forecast LAUF volumes, the Company calculated an LAUF Factor by dividing actual LAUF volumes as a percent of total metered usage for the period from 2013 through 2022. Over the 10-year historical period, the average LAUF percentage is 1.78%, as shown in Figure 27.

Figure 27: Lost and Unaccounted for Gas Analysis

Gas Year	Company Use
2013	2.18%
2014	1.59%
2015	1.72%
2016	1.72%
2017	1.97%
2018	2.24%
2019	1.46%
2020	0.43%
2021	1.98%
2022	2.49%
10 Year Average	1.78%

During the forecast period, the losses associated with firm sendout and capacity eligible transportation is expected to increase by 1.25% per year as shown in Figure 28 below.

Figure 28: Unaccounted for Forecast Volumes (MMBtu – Normal Year)

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	431,401	139,762	258,347	829,510
2024/25	424,635	137,946	259,106	821,687
2025/26	429,795	139,127	262,926	831,848
2026/27	443,468	142,676	267,925	854,069
2027/28	453,524	145,584	272,556	871,664
CAGR	1.26%	1.03%	1.35%	1.25%

55 The major sources of lost and unaccounted for gas include meter measurement variances; billing and record keeping variances, distribution system losses (e.g. leaks, third party damage) and unmeasured usage.

12. Forecast of Unbilled Sales

To account for unbilled volumes, the Company used net unbilled history back to 2016. For each month from January 2016 through December 2022, the Company calculated historical average net unbilled. Those monthly historical averages became the forecast for net unbilled. The annual sum of net unbilled in this history is shown below in Figure 29.

Figure 29: Historical Unbilled Sales (MMBtu)[56]

Gas Year	Sum of Net Unbilled
2017/18	994,886
2018/19	(1,007,630)
2019/20	(325,187)
2020/21	(342,229)
2021/22	(189,300)

The annual forecast of unbilled sales volumes is shown in Figure 30 below.

Figure 30: Unbilled Sales Forecast (MMBtu – Normal Year)[57]

Gas Year	Unbilled Forecast All Division
2023/24	(82,126)
2024/25	(82,126)
2025/26	(82,126)
2026/27	(82,126)
2027/28	(82,126)

56 Historical Unbilled Sales are total system unbilled sales.

57 Forecast Unbilled Sales are planning load unbilled sales.

The total forecast monthly unbilled sales are allocated to division and customer segment based on the ratio of volumes for each customer segment and division to total firm sales and transportation. See Appendix 10.

13. Energy Efficiency

The Company's forecast includes actual load reductions achieved from energy efficiency measures that were installed through 2022,[58] are planned to be installed through 2024 pursuant to the Company's Department-approved 2022-2024 Three-Year Energy Efficiency Plan ("Plan").[59] The subsequent years, 2025 through 2032, are held constant at the 2024 level. These actual, planned, and forecast values were developed by the Company's Energy Efficiency department and reflect the most recent information, consistent with the Company's Department-approved 2022-2024 Plan. Figure 31 below illustrates the cumulative savings in MMBtu due to energy efficiency used in this forecast.

For background and context, an Act Relative to Green Communities, Chapter 169 of the Acts of 2008 ("Green Communities Act" or "Act") was signed into law on July 2, 2008. This legislation was designed to promote enhanced energy efficiency throughout the Commonwealth and in so doing, the Green Communities Act required gas (and electric) distribution companies and municipal aggregators ("Program Administrators") to develop energy efficiency plans to "provide for the acquisition of all available energy efficiency demand reduction resources that are cost effective or less expensive than supply." G.L. c. 25, § 21(b)(1). In 2021, the GCA was amended[60] to additionally mandate Massachusetts Program Administrators to construct the Energy Efficiency Plan to meet or exceed the GHG emissions target goals set by the EEA secretary

58 See Columbia Gas of Massachusetts, D.P.U. 16-120 (2013-2015 Energy Efficiency Term Report Data Tables, submitted to the Department August 1, 2016 and revised February 21, 2017); Columbia Gas of Massachusetts, D.P.U. 19-90 (2016-2018 Term Report Data Tables, submitted to the Department August 1, 2019 and revised January 31, 2020); Eversource Gas Company of Massachusetts, D.P.U 22-111 (2019-2021 Term Report Data Tables, submitted to the department August 1, 2022 and revised April 18, 2023) and Eversource Gas of Massachusetts, D.P.U. 23-60 (2022 Plan-Year Report Data Tables, submitted to the Department June 1, 2023).

59 See D.P.U. 21-121 (2022-2024 Three-Year Plan Data Tables, submitted April 1, 2022).

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60 Acts of 2021, c.8

pursuant to G.L. c. 21N, § 3B. In October 2021, Eversource Gas Company of Massachusetts d/b/a Eversource Energy, along with the other Program Administrators in the Commonwealth, developed and filed a comprehensive statewide energy efficiency plan for the period 2022 through 2024 that not only advanced the objectives of the Green Communities Act, but also promoted the parallel goals of decreasing GHGs and promoting job creation in the clean energy sector.

As part of the Company's recently approved Plan for 2022-2024 in Eversource Gas Company of Massachusetts d/b/a Eversource Energy, D.P.U. 21-121, the Company developed a comprehensive set of energy efficiency programs and correspondingly appropriate budgets and expected savings associated with these programs. The portfolio of programs targets the residential, income eligible, and C&I markets and serves all utility customers.

The Company employed the TRC test, as required and approved by the Department in its Order in D.P.U. 08-50-A, to analyze the cost effectiveness of the gas energy efficiency programs in its Plan for each of the three years, 2022-2024. See Eversource Gas Company of Massachusetts d/b/a Eversource Energy, D.P.U. 21-121 at Exh. 4 (Cost-Effectiveness Tables) and Exh. 5 (BCR Model). The TRC test measures the value of avoided gas supply and any additional direct economic benefits against the costs of a program to participating customers. The avoided gas supply costs used in these cost-effectiveness determinations are based on Appendix C of the "Avoided Energy Supply Components in New England: 2021 Report" March 15, 2021 (Revised May 14, 2021), prepared for the Avoided Energy Supply Component (AESC) Study Group, by Synapse Energy Economics, Resource Insights et al.[61] See D.P.U. 21-120 to D.P.U. 21-129, "2022-2024 Massachusetts Joint Statewide Three-Year Electric and Gas Energy Efficiency Investment Plan" Exhibit 1, Appendix Q (November 1, 2021). All programs were found to be cost-effective. See, D.P.U. 21-120 through D.P.U. 21-129 at 325 (January 31, 2022).

[61] Unlike previous studies, the 2015, 2018 and 2021 AESC studies were designed to be updated in synch with the three-year planning cycle of energy efficiency plans required by the GCA. A three-year cycle for the AESC study is consistent with the Department's focus on the three-year planning and performance construct envisioned by the GCA. D.P.U. 11-120-A, Phase II at 2.

The Company used the methodology approved in its 2021 EGMA Gas Company Supply Plan (D.P.U. 21-118) to reflect energy efficiency in the Planning Load forecast. These Planning Load forecasts discussed above were modeled without energy efficiency-related adjustments to the historical values; therefore, the resulting models include historical energy efficiency savings. For projected sales and/or transportation the amount of new energy efficiency that exceeds the historical trend value from 2012 to 2021 was deducted from the forecast to account for forecasted energy efficiency savings. Appendix 11 demonstrates these calculations in detail.

Figure 31: Energy Efficiency Savings Projections (Dekatherms)

Year	Residential & Low	Commercial & Industrial	Total
2012	306,439	444,889	751,328
2013	481,131	640,904	1,122,035
2014	681,673	849,045	1,530,718
2015	927,467	969,792	1,897,259
2016	1,182,713	1,095,685	2,278,399
2017	1,415,762	1,187,039	2,602,801
2018	1,698,660	1,375,902	3,074,563
2019	1,991,394	1,500,004	3,491,398
2020	2,249,710	1,624,007	3,873,716
2021	2,520,493	1,748,037	4,268,530
2022	2,807,809	1,872,252	4,680,061
2023	3,095,125	1,996,467	5,091,592
2024	3,382,441	2,120,683	5,503,123
2025	3,669,757	2,244,898	5,914,655
2026	3,957,073	2,369,113	6,326,186

14. Firm Planning Load Forecast

The normal year firm planning load forecast was calculated by summing the normal year forecasts for the four customer segments (reduced by expected savings from energy efficiency programs and capacity-exempt transportation), plus Company Use, Lost and Unaccounted for gas sales.

The total number of planning load customers is projected to increase over the forecast period by 0.98% per year, as shown in Figure 32. Gas year customers shown in Figure 32 are the average number of customers.

Figure 32: Total Company Customer Forecast Number of Customers

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	170,312	52,286	110,997	333,596
2024/25	172,222	52,655	111,558	336,434
2025/26	174,203	53,236	112,201	339,640
2026/27	176,411	53,974	112,930	343,314
2027/28	178,412	54,706	113,689	346,807
CAGR	1.17%	1.14%	0.60%	0.98%

As shown in Figure 33, the total firm planning load, after adjustments for Company Use, losses and energy efficiency, is projected to increase by 1.14% per year over the forecast period.

Figure 33: Firm Planning Load Forecast (MMBtu – Normal Year)

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2023/24	24,440,952	7,868,908	14,572,089	46,881,949
2024/25	24,034,477	7,757,356	14,599,437	46,391,270
2025/26	24,298,549	7,814,476	14,799,130	46,912,155
2026/27	25,040,991	8,004,961	15,065,449	48,111,401
2027/28	25,580,202	8,159,236	15,311,165	49,050,603
CAGR	1.15%	0.91%	1.24%	1.14%

D. CUSTOMER DEMAND SCENARIOS

In addition to the base-case forecast results discussed in Sections III.B and III.C, the Company developed a high-case scenario and a low-case scenario. The high-case reflects a more optimistic set of economic drivers; the low-case forecast reflects a below-trend economic scenario from Moody's.

Over the forecast period, the total EGMA base-case annual, traditional Planning Load is projected to increase by 1.14% per year; the high-case scenario projects Planning Load will increase by 1.34% annually; the low-case scenario projects Planning Load will increase by 0.74%

annually. A summary of the high-case, low-case and base-case forecast results are provided in figure 34 below:

Figure 34: Firm Planning Load Forecast (MMBtu – Normal Year)

Brockton			
Gas Year	Base	High	Low
2023/24	24,440,952	24,493,622	24,354,683
2024/25	24,034,477	24,299,755	23,481,860
2025/26	24,298,549	24,653,061	23,615,714
2026/27	25,040,991	25,428,630	24,414,018
2027/28	25,580,202	25,954,935	25,036,001
CAGR	1.15%	1.46%	0.69%

Lawrence			
Gas Year	Base	High	Low
2023/24	7,868,908	7,883,269	7,873,094
2024/25	7,757,356	7,770,193	7,745,783
2025/26	7,814,476	7,830,558	7,767,578
2026/27	8,004,961	8,028,614	7,911,661
2027/28	8,159,236	8,194,416	8,026,207
CAGR	0.91%	0.97%	0.48%

Springfield			
Gas Year	Base	High	Low
2023/24	14,572,089	14,595,645	14,552,044
2024/25	14,599,437	14,633,987	14,546,856
2025/26	14,799,130	14,843,099	14,703,121
2026/27	15,065,449	15,122,978	14,920,681
2027/28	15,311,165	15,383,966	15,123,909
CAGR	1.24%	1.32%	0.97%

Eversource Gas Of Massachussetts Gas Total			
Gas Year	Base	High	Low

2023/24	46,881,949	46,972,536	46,779,822
2024/25	46,391,270	46,703,935	45,774,499
2025/26	46,912,155	47,326,718	46,086,412
2026/27	48,111,401	48,580,222	47,246,360
2027/28	49,050,603	49,533,317	48,186,118
CAGR	1.14%	1.34%	0.74%

IV DEVELOPMENT OF PLANNING STANDARDS AND PLANNING REQUIREMENTS

A. INTRODUCTION

The role of weather is critical in all aspects of the Company's supply planning process, including forecasting, resource planning and resource acquisition. Because most of the Company's sendout is temperature sensitive, temperature is a primary driver of firm sendout. The impact of temperature is reflected in the choice of a weather variable to apply consistently in all modeling and planning processes, including econometric models, normal-year, design-year, design-day and cold-snap analysis. The Company uses Effective Degree Days which take into account the effect of wind speeds, rather than conventional Heating Degree Days. This is in compliance with Department directives.

In this section, the Company describes the development of its design planning standards for normal year, design year, and design day. The normal year is defined as a weather pattern consistent with a distribution of EDDs that has the same number of EDDs for a given period above each EDD level as the historical EDD period. The period used for the normal EDD distribution calculations is the period from November 2002 through October 2022. Figure 35 provides the normal year monthly EDD levels for each of the Company's Divisions, Brockton, Springfield, and Lawrence.

The Company used the same historical EDD database used by Columbia Gas of Massachusetts ("CMA") in its previous Forecast & Supply Plan (F&SP)[62] and added the most

[62] D.P.U 19-135, filed October 30, 2019 and approved October 27, 2020, and D.P.U 21-118, filed November 2, 2021 and approved October 31, 2022.

recent available data to the database. EGMA decided to use a Gas Year basis (November through October) instead of the Calendar Year basis used by CMA. For design planning purposes, EGMA used the entire available historical database from November 1967 through October 2022 to take advantage of the more complete dataset.

The Company acknowledges that, the normal weather standard, based on most recent 20 years of EDD data, has warmed as the region has experienced several warmer than normal winter seasons in last decade. However, during this same time period, the design winter standard increased as extreme cold events are relatively common in New England and cold snaps can cause minimum temperatures well below zero across the service territory. A review of recent weather data demonstrates that some of the most significant cold weather events have occurred during the last decade.

B. Normal Year Planning Standard

To develop the normal year planning standard, the Company developed frequency distributions for EDDs for each division for each month based on the 20-year average of the EDD data above each EDD level. The EDDs for each location for each month were then distributed over each month based on average daily EDD levels for each corresponding division, with the highest EDD levels paired with the days that had the highest average EDD. Although the EDD levels in each division generally differ on any given day, the EDD levels in the various divisions are closely correlated.

The result of this analysis is a distribution of EDD within a month that has the 20- year average of EDDs above each EDD level, arranged in an order set by the average daily EDD level during the 20-year base period. This eliminates the need to distribute EDDs in a manner based on a particular actual month's EDDs, which may or may not actually be reasonably distributed. Figure 35 below provides the normal year EDD levels for each month by Division.

Figure 35
EGMA Normal Year EDDs
(Based on Nov 2002 - Oct 2022 Data)

	Brockton	Springfield	Lawrence
November	712	734	767
December	1,039	1,073	1,111
January	1,241	1,284	1,313
February	1,056	1,087	1,118
March	927	918	979
April	555	514	594
May	261	208	291
June	58	38	75
July	0	0	0
August	0	0	0
September	96	90	120
October	385	395	435
Winter Subtotal	4,975	5,096	5,288
Summer Subtotal	1,355	1,245	1,515
Total	6,330	6,341	6,803

C. DESIGN YEAR AND DESIGN DAY PLANNING STANDARDS

As indicated above, the Company's customer load is highly temperature sensitive, with the greatest demand during the coldest periods of the year. If appropriate planning is not adopted to address periods of extreme cold weather, the demand for gas may exceed available supply resulting in shortages, the consequences of which could be severe, ranging from large pipeline penalties to system depressurization and customer outages. To avoid the potential negative effects of shortages, the Company plans its resource portfolio to ensure that adequate resources are available during very severe weather conditions.

1. Review of Historical Frequency of Occurrences

The Company reviewed the historical weather data for each division for the 55 gas years between November 1967 and October 2022 to determine the five coldest winter periods and their respective recurrence periods, or probabilities. Using the distribution of the historical winter season EDD data, the Company calculated design winter standards for various occurrence probabilities and also noted the frequency of a potential design standard being exceeded during the 55-year historical period. This information is summarized in Figure 36 below. The analysis shows that the coldest winter in the past 55 years has a recurrence period ranging from 23 years in Springfield, to 29 years in Brockton, and to 36 years in Lawrence.

Figure 36: EGMA Design Winter EDD Analysis
(Data from November 1967 through October 2022)

Brockton 151 Day Winter				Springfield 151 Day Winter				Lawrence 151 Day Winter			
Mean	5,001	EDD		Mean	5,191	EDD		Mean	5,239	EDD	
Stand Dev	439.374	Level	Rec Per	Stand Dev	373.899	Level	Rec Per	Stand Dev	447.684	Level	Rec Per
Maximum	2014-15	5,798	28.7	Maximum	1968-69	5,832	23.2	Maximum	2014-15	6,096	35.9
2nd highest	2013-14	5,629	13.1	2nd highest	1969-70	5,792	18.6	2nd highest	2013-14	5,951	17.9
3rd highest	1968-69	5,627	13.0	3rd highest	2014-15	5,710	12.1	3rd highest	2002-03	5,919	15.5
4th highest	1967-68	5,620	12.6	4th highest	2013-14	5,702	11.7	4th highest	1968-69	5,879	13.1
5th highest	1969-70	5,601	11.6	5th highest	1993-94	5,681	10.5	5th highest	1967-68	5,872	12.7
Alternative Standards		6,023.4	100.0	Alternative Standards		6,060.3	100.0	Alternative Standards		6,280.7	100.0
		5,975.0	75.0			6,019.2	75.0			6,231.4	75.0
		5,903.6	50.0			5,958.4	50.0			6,158.6	50.0
		5,825.7	33.0			5,892.1	33.0			6,079.2	33.0
		5,807.0	30.0			5,876.2	30.0			6,060.2	30.0
		5,770.4	25.0			5,845.1	25.0			6,023.0	25.0
Proposed Standard		5,826	33.1	Proposed Standard		5,892.0	33.0	Proposed Standard		6,079.0	33.0

The Company also conducted a similar statistical analysis of 24-day cold snaps for each of the EGMA divisions, based on the highest 24-day EDD level experienced during each winter season. The 24-day cold snap is an important component of a design winter. The Company used the actual pattern of EDDs for the period of January 7, 2004 through January 30, 2004 as the basis for the 24-day cold snap; which included the Company's historical peak days. Adjustments were made to make the adjusted total EDDs for the period to match the 1:33 level. A summary of historical 24-day cold snap analysis is provided in Figure 37 below.

Figure 37: EGMA Cold Snap EDD Analysis

(Data from November 1967 through October 2022)

Brockton 24-Day Cold Snap			
Mean	1,089.6	EDD Level	Rec Per
Stand Dev	119.592		
Maximum	1/07/04 to 1/30/04	1,325	40.8
2nd highest	1/28/15 to 2/20/15	1,287	20.2
3rd highest	1/28/79 to 2/20/79	1,286	19.9
4th highest	1/6/82 to 1/29/82	1,275	16.5
5th highest	1/12/71 to 2/4/71	1,271	15.5
Alternative Standards		1,367.8	100.0
		1,354.6	75.0
		1,335.2	50.0
		1,314.0	33.0
		1,308.9	30.0
		1,298.9	25.0
Proposed Standard		1,314	33.0

Sprinfield 24-Day Cold Snap			
Mean	1,125.3	EDD Level	Rec Per
Stand Dev	117.676		
Maximum	1/07/04 to 1/30/04	1,330	24.4
2nd highest	12/25/80 to 1/17/81	1,328	23.5
3rd highest	1/29/79 to 2/21/79	1,325	22.3
4th highest	1/1/70 to 1/24/70	1,294	13.2
5th highest	1/6/82 to 1/29/82	1,288	12.0
Alternative Standards		1,399.1	100.0
		1,386.1	75.0
		1,367.0	50.0
		1,346.1	33.0
		1,341.1	30.0
		1,331.3	25.0
Proposed Standard		1,346.0	32.9

Lawrence 24-Day Cold Snap			
Mean	1,129.4	EDD Level	Rec Per
Stand Dev	119.634		
Maximum	1/07/04 to 1/30/04	1,371	46.0
2nd highest	1/25/15 to 2/17/15	1,342	26.5
3rd highest	1/4/94 to 1/27/94	1,317	17.1
4th highest	12/26/67 to 1/18/68	1,314	16.3
5th highest	1/6/82 to 1/29/82	1,308	14.8
Alternative Standards		1,407.7	100.0
		1,394.6	75.0
		1,375.1	50.0
		1,353.9	33.0
		1,348.8	30.0
		1,338.9	25.0
Proposed Standard		1,354.0	33.1

The recurrence periods for the 24-day cold snaps ranged from 24 years in Springfield, to 41 years in Brockton, and 46 years in Lawrence. Once the decision was made to retain the 1:33 design winter standard and the 1:33 design day standard, (discussed below) the Company applied the same 1:33 standard to the cold snap analysis. This resulted in an upward adjustment in Springfield, and downward adjustments in Brockton and Lawrence.

The Company also conducted a similar statistical analysis of peak days for each of the EGMA divisions, based on the highest EDD experienced during each winter season. A summary of the five days with the highest EDD level in each division and the calculated recurrence probabilities are provided in Figure 38 below.

The coldest days in each of the three areas are very extreme with large recurrence periods. The analysis shows that the coldest day in Lawrence in the past 55 years (84 EDD) has a recurrence period of 190 years; the coldest day in Springfield (81 EDD) has a recurrence period of 111 years, and the coldest day in Brockton (79 EDD) has a recurrence period of 51 years. In Lawrence, the second highest EDD (82 EDD) has a 1 in 79 recurrence probability, the second coldest day in Springfield (80 EDD) has a 1 in 72 recurrence probability; and the second coldest day in Brockton (78 EDD) has a 1 in 35 recurrence probability.

Figure 38: EGMA Design Day EDD Analysis
(Data from November 1967 through October 2022)

Brockton Design Day			
Mean	66.0	EDD	
Stand Dev	6.333	Level	Rec Per
Maximum	01/08/68	79	50.6
2nd highest	01/17/82	**78**	34.9
3rd highest	01/15/04	**78**	34.9
4th highest	01/04/81	77	24.6
5th highest	01/22/76	75	13.0
Alternative Standards		80	75.0
		79	50.6
		78	34.9
		77	24.6
		76	17.7
Alternative Standards		80.7	100.0
		80.0	75.0
		79.0	50.0
		77.8	33.0
		77.6	30.0
		77.1	25.0
Proposed Standard		**78**	**34.9**
Note: Brockton Standard exceeded 1 time			
Proposed Brockton standard is:			**78**

Springfield Design Day			
Mean	66.6	EDD	
Stand Dev	6.103	Level	Rec Per
Maximum	12/25/80	81	111.0
2nd highest	01/08/68	80	72.2
3rd highest	01/15/04	**78**	32.8
4th highest	02/13/16	77	22.9
5th highest	12/25/68	74	9.0
Alternative Standards		80	72.2
		79	48.1
		78	32.8
		77	22.9
		76	16.4
Alternative Standards		80.8	100.0
		80.1	75.0
		79.1	50.0
		78.0	33.0
		77.8	30.0
		77.2	25.0
Proposed Standard		**78**	**32.8**
Note: Springfield Standard exceeded 2 times			
Proposed Springfield standard is:			**78**

Lawrence Design Day			
Mean	68.1	EDD	
Stand Dev	6.219	Level	Rec Per
Maximum	01/08/68	84	190.0
2nd highest	01/15/04	82	79.0
3rd highest	12/25/68	78	18.0
4th highest	12/25/80	77	13.2
5th highest	01/17/82	76	9.8
Alternative Standards		84	190.0
		83	121.1
		82	79.0
		81	52.7
		80	36.0
Alternative Standards		82.6	100.0
		81.9	75.0
		80.9	50.0
		79.8	33.0
		79.5	30.0
		79.0	25.0
Proposed Standard		**80**	**36.0**
Note: Lawrence Standard exceeded 2 times			
Proposed Lawrence standard is:			**80**

**On February 3, 2023, EGMA observed a 79 EDD in the Springfield Division, a 79 EDD in its Lawrence Division and a 72 EDD in its Brockton Division.*

2. <u>Basis for Selecting Design Winter Planning Standard</u>

While the rationale for establishing a design day standard is straight forward, the need for a design winter standard is less obvious. Because many winter seasonal supplies, such as underground storage, and peak shaving LNG and propane facilities are subject to seasonal capacity constraints and re-supply requirements, a winter seasonal standard is required to insure that supplies are available on the last cold day of the winter. When load requirements can simply be met by increasing purchases of flowing supplies, seasonal volume limitations are not important. However, if the marginal supply is a source that has seasonal capacity constraints, a winter design standard is essential.

A design winter concern could be caused by diminished levels of underground storage or LNG inventories after a period of higher than normal EDDs. These inventories can be stretched by substituting available alternative supplies, such as purchasing flowing supplies in Appalachia to displace withdrawals from nearby underground storage fields. A delivered city-gate supply might be available to be arranged to avoid an LNG inventory shortfall. However, in a capacity constrained market such as New England, a Company cannot assume that such supplies would be available whenever they might be necessary. Such supplies need to be purchased in advance to guarantee their availability. The Company is required to make a trade-off between acquiring expensive winter seasonal supplies and providing an adequate level of reliability to avoid the extreme consequences of a loss of load.

The Company has established a design winter standard of 1:33, which the Department has approved since the Company's order in D.P.U. 06-84. Given the current winter capacity and supply constraints in the New England market and the fact that the constraints will not likely be lessened by the construction of incremental capacity, the retention of the long standing 1:33 standard is appropriate.

Figure 39 provides a summary of the EGMA design winter and design day standards, discussed further below.

Figure 39: EGMA Summary of Design Planning Standards (Data from November 1967 through October 2022)

	Brockton	Springfield	Lawrence
Design Winter (1:33)	5,826	5,892	6,079
Design Day (1:33)	78	78	80

3. Basis for Selecting Design Day Planning Standard

The design day represents the single highest EDD the Company's resource portfolio must be structured to meet. Although the Company may have some flexibility in meeting design winter needs by taking advantage of short-term spot market-area arrangements throughout the winter season on warmer days, the Company does not believe that it is appropriate to rely on spot gas arrangements in meeting design-day conditions.

The choice of the specific design day standard is not simply a matter of “letting the numbers” determine the standard. The recurrence periods for the Company’s highest daily EDD levels in each divisions are very large. Because the EDD levels differ between the geographical areas, the recurrence probabilities of the coldest days are not the same. As shown in Figure 38, on January 8, 1968, the Lawrence Division experienced an 84 EDD; the Springfield Division experienced an 80 EDD; and. the Brockton Division experienced a 79 EDD. The recurrence probabilities for the EDDs experienced that day were 1:190 in Lawrence, 1:72 in Springfield, and 1:50 in Brockton.

The Company has been using and the Department has been approving a 1:33 design day design standard since its filing in D.P.U. 06-84. The 1:33 standard continues to provide a reasonable balance between the high cost of winter seasonal supplies and the extreme costs of a loss of load due to inadequate supplies. The overall lack of pipeline capacity in the New England market, largely the result of electric generators not willing or able to pay for incremental capacity, justifies the high design day standard. Based on the updated EDD data used for the current filing, this standard translates to a 78 EDD design day level in Brockton and Springfield, and an 80 EDD design day in Lawrence, as shown in Figure 39 above.

D. CALCULATING DESIGN WINTER AND DESIGN DAY EFFECTIVE DEGREE DAYS

Once the choice of the standard for design winter and design day was verified by the Company’s evaluation of the Company’s design standard analysis, the calculation of the actual EDD level for the 1:33 recurrence periods were straightforward. Given the assumption that the winter EDDs, cold snap EDDs, and peak day EDDs were normally distributed, with known mean and standard deviations, the Company used the Excel statistical function to calculate the design EDDs for various probability levels.

The distribution of design year EDDs is derived based on the normal year EDD distributions with adjustments made for the winter season. The total number of winter EDDs was derived statistically, as discussed in the section on design winter EDDs. The total number of January EDDs was derived in a similar manner. The total number or EDDs for the other months were distributed based on the same percentage of non-January winter EDD s as the normal weather EDDs and are allocated by days within the month by multiplying the normal EDDs by the ratio of design winter month EDDs to normal winter month EDDs. The derived cold snap number of EDDs are distributed according to the actual distribution for the January 7, 2004 through January 30, 2004 period, with minor adjustments such that the total is equal to the 1:33 level of EDDs. The rest of January EDDs are adjusted by a factor that results in the total January EDDs are equal to the January 1:33 EDD level. The design year summer EDDS are the same as the normal year EDDs.

Figure 40 shows the monthly distribution of design year EDDs for each of the EGMA divisions. Figure 41 shows the distribution of EDDs for the January Cold Snap by Division.

Figure 40
EGMA Design Year Monthly EDDs
(November 1967 through October 2022)

	Brockton	Springfield	Lawrence
November	810	830	859
December	1,181	1,211	1,242
January	1,581	1,588	1,634
February	1,201	1,227	1,250
March	1,053	1,036	1,095
April	555	514	594
May	261	208	291
June	58	38	75
July	0	0	0
August	0	0	0
September	96	90	120
October	385	395	435
Winter Subtotal	5,826	5,892	6,080
Summer Subtotal	1,355	1,245	1,515
Annual Total	7,181	7,137	7,595

Figure 41
EGMA 24 -Day January Cold Snap Analysis
(November 1967 through October 2022)

Date	Brockton	Springfield	Lawrence
1	29	25	33
2	40	35	45
3	44	46	50
4	33	30	31
5	37	32	37
6	41	39	40
7	**54**	**55**	**56**
8	**59**	**56**	**66**
9	**69**	**70**	**72**
10	**65**	**65**	**66**
11	**45**	**48**	**47**
12	**38**	**37**	**41**
13	**57**	**58**	**61**
14	**70**	**71**	**72**
15	**78**	**78**	**80**
16	**64**	**62**	**64**
17	**37**	**42**	**38**
18	**40**	**44**	**42**
19	**53**	**56**	**52**
20	**55**	**55**	**54**
21	**49**	**50**	**49**
22	**47**	**50**	**48**
23	**60**	**59**	**61**
24	**66**	**67**	**70**
25	**60**	**60**	**65**
26	**53**	**56**	**56**
27	**46**	**50**	**45**
28	**44**	**48**	**46**
29	**54**	**56**	**52**
30	**51**	**53**	**51**
31	43	35	44

Cold Snap Indicated by Bold font & Shading
Design Day is January 15

E. Calculating Design Winter Planning load requirements

The design year load requirements are primarily based on the normal year forecast with some minor adjustments. The process used for determining the EGMA planning load requirements is based on the process that the Company has successfully used in the two most recent NSTAR Gas Long Range Forecasts and Supply Plans. The normal year monthly forecasts are split into daily base loads and monthly temperature sensitive loads, which are subsequently divided by the normal number of EDDs to derive monthly temperature sensitive sendout per EDD factors. The factors based on the unadjusted monthly load forecasts generally require adjustment prior to their being input to the SENDOUT Model and applied to the normal year daily distribution of EDDs to determine the normal year monthly requirements.

V RESOURCE PORTFOLIO ANALYSES

A EGMA's Decision-Making Process

The Department has reviewed and approved the Company's prior F&SP filings, the last five of which were docketed as, D.P.U. 13-161, D.P.U. 15-143 , D.P.U. 17-166, D.P.U 19-135 and D.P.U. 21-118. The Department summarized its findings following its investigation of EGMA's last F&SP, D.P.U. 21-118, as follows:

> The Company has demonstrated that its supply portfolio is adequate to satisfy forecast normal-year, design-year, design-day, and cold-snap sendout requirements under base-case and high-growth conditions throughout the forecast period (Exh. EGMA-1, at 93-95, & App. 1, at 13,15, 18). Given the Company's approved supply planning process, the Department finds that the Company can reasonably be expected to secure incremental supplies that will satisfy its projected requirements under the high-growth scenario. Accordingly, the Department finds that EGMA has established that it possesses adequate supplies to meet its expected normal-year, design-year, design-day, and cold-snap sendout requirements throughout the forecast period.

D.P.U. 21-118, at 29.

Also, the Department has reviewed EGMA's planning process and associated results in its various decisions approving specific resource acquisitions, most recently in D.P.U. 10-49, D.P.U. 10-65, D.P.U. 10-134, D.P.U. 12-04, D.P.U. 12-64, D.P.U. 13-158, D.P.U. 15-39,[63] D.P.U. 15-142, D.P.U. 15-170, D.P.U. 15-175, D.P.U. 17-85, D.P.U. 17-97, D.P.U. 17-166, D.P.U. 21-09, and D.P.U 20-149. In each of these proceedings, the Department found that the Company's demand forecasting and supply planning processes are consistent with the Department's requirements. In these various Department decisions, the Department found that EGMA's resource decisions contributed to meeting the Company's interrelated goals of flexibility, diversity, viability and least-cost. Further, in each of the above proceedings, the Department found EGMA's planning process to be reasonable and appropriate.

As explained in this section, EGMA's resource planning process is largely unchanged since its previously approved Plan noting that the process appropriately takes into consideration changing market dynamics at the wholesale and retail levels.

1 **EGMA's Planning Goals**

EGMA's decision-making process requires the Company to establish appropriate goals and objectives, consistent with both Department policy and sound LDC practice in providing the most beneficial service to its customers. The primary goal of EGMA's planning process is to acquire and manage all available resources in a manner that achieves a least-cost resource portfolio for its customers. A least-cost portfolio appropriately balances lower costs with other important non-cost criteria such as reliability, viability and flexibility. Pursuit of a least-cost portfolio allows EGMA to provide its customers with reliable service at a reasonable cost.

The Company's overall portfolio objective is supported by a number of specific resource planning objectives, which are summarized as follows:

(1) minimize portfolio costs of available supplies;

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[63] The Northeast Energy Direct project was withdrawn by TGP after Department approval.

(2) maintain portfolio security/reliability (which includes enhancing diversity across pipelines and supply basins);

(3) provide contract flexibility; and

(4) acquire viable resources.

EGMA's resource planning process employs analytical tools, including the SENDOUT® cost optimization model along with its various assessment methods, to perform long-range planning and to evaluate the individual resource decisions it must make. Non-cost resource evaluation is typically performed using spreadsheet-based assessment tools. Taken together, these tools and methods ensure that the planning process is thorough, and that it remains objective in its pursuit of a least-cost portfolio.

2 EGMA's Planning Process

Effective resource planning requires both an excellent understanding of an LDC's own customers and markets, as well as insights into opportunities and developments in wholesale markets. Through its resource planning process, EGMA seeks to match its long-term resource needs with available market opportunities (e.g., new capacity or gas supply options).

EGMA performs long and short-range analyses of its portfolio and potential need for adjustment to achieve its planning objectives on an ongoing basis. Additionally, the Company performs comprehensive analyses any time a decision to modify the portfolio of resources under contract is being considered. This analysis includes a determination of need, and any associated change of need, and an evaluation of potential resource options.

Any decision to modify the portfolio begins with a determination of need based on the current resources under contract, including market (pricing) dynamics, and current demand forecasts. EGMA's portfolio requirements are driven by EGMA's design weather conditions and the associated requirements of its customers as reflected in its forecasts of (normal and design) annual, peak season, cold snap, daily and hourly requirements developed using the forecasting models described earlier in Section III and augmented by system analysis of hourly flow rates necessary to maintain system pressures. Hourly demand fluctuations have a dramatic impact on the upstream supply availability and pressures which are critical to safely and reliably serving the dynamic customer demand in highly variable weather conditions. Comparison of the demand forecasts to the existing portfolio establishes whether EGMA's portfolio is projected to be adequate over the planning horizon, and if not, the quantity and duration of any deficiency. Similarly, this comparison also indicates whether there is an imbalance of resources in the portfolio in any of the years over the planning horizon, which may be released, de-contracted or sold in wholesale markets.

At the time that a need is established by a projected deficiency, EGMA compiles a comprehensive set of alternative portfolio options that could meet the anticipated need. EGMA is an active participant in regional capacity markets for both the purchase and sale of capacity resources on a bundled and unbundled basis. EGMA's market participation provides important market intelligence on developments in wholesale markets and is relied upon, in part, to compile resource alternatives. Further, the Company typically may issues a Request for Proposal ("RFP") as part of the competitive process to assure it receives the best bids from the market at that time. EGMA also specifies the criteria to be used in the evaluation of the array of resource options, which entails selecting the appropriate weighting among the price and non-price evaluation criteria incorporated in the planning process. Consistent with its portfolio goals, the resource evaluation criteria employed by EGMA are (1) price, (2) supply security, (3) contract flexibility and (4) supplier viability, which take on varying degrees of importance depending on the type of resource decision being made and anticipated market conditions.

Once the full range of resource options has been analyzed, EGMA selects the best resource alternative or alternatives to pursue. In selecting the best alternative, EGMA evaluates present and anticipated future market conditions as well as risks associated with its decision. Depending on the type of resource, there can be a long lead-time between the decision point and the in-service date. This typically occurs when incremental capacity resources are required, which would be taken into consideration in the Company's Action Plan.

3 Least-Cost Planning Techniques

The first element of the Department's standard of review is whether least-cost planning techniques were used in the decision-making process. The Department has previously indicated that EGMA's planning process appropriately minimizes costs:

> The Company has provided evidence that it has a resource planning process that ensures its ability to acquire least-cost supply for its customers. With the use of the SENDOUT® model, EGMA is able to consider physical limitations and contract constraints, and to determine the minimum cost dispatch for a particular period (Exh. EGMA-1, at 91).
>
> The Department has held that for a gas company's planning process to minimize cost, that process must adequately consider all resource options, including energy efficiency, on an equal basis. D.P.U. 93-13, at 88. The evidence shows that the Company's process adequately considers all resource options on an equal basis, and it has appropriately accounted for the effect of its energy efficiency programs (Exh. EGMA-1, at 90-92). Accordingly, the Department finds that the Company has formulated an appropriate process for identifying a comprehensive array of supply options and has developed appropriate criteria for screening and comparing supply resources. In addition, we find that the Company has demonstrated that the contracts for which it requests renewal provide least-cost service to meet the needs of the Company's customers and will continue to provide the same service after renewal (Exh. EGMA-1, at 83-88).
>
> D.P.U. 21-118, at 24.

In Bay State Gas Company, D.T.E. 98-86 (2000) and other Company proceedings, the Department commented on EGMA's use of the SENDOUT® cost optimization model to evaluate the cost effectiveness of various supply options, wherein it stated:

> "Bay State has demonstrated that it has in place processes by which it develops resource planning strategies to maintain reliable, least-cost service to its firm sales customers. The Department therefore finds that Bay State's SENDOUT model allows the Company to identify a variety of capacity and commodity options under multiple planning contingencies and migration scenarios."
>
> D.T.E. 98-86, at 30.

EGMA continues to utilize the SENDOUT® model as its primary tool for designing a least-cost portfolio of supply options.

As explained more fully below, the Company also utilizes an appropriate analytical framework for evaluating the cost-effectiveness of potential EE resources. Thus, EGMA's resource planning process accomplishes the Department's goal of achieving least-cost.

4 Analytical Tools

EGMA utilizes important analytical tools to ensure a comprehensive evaluation of its total portfolio resource alternatives and resultant decisions. Central among these is the use of EGMA's SENDOUT® model that optimizes the utilization of all resources in the portfolio under various weather patterns, including design and normal conditions. EGMA also considers various growth scenarios related to its design day and annual demand forecasts, including base, high and low. This helps ensure that EGMA's planning techniques result in least-cost decisions. As noted above, the Company's use of this model has been cited by the Department in recent F&SP and other proceedings as appropriate to ensure that EGMA's planning techniques are least-cost. SENDOUT® can also select the lowest cost mix of resources from among an array of specified options. EGMA employs other analytical techniques, such as the use of spreadsheets, to enhance the evaluation of resource options. These tools aid in the assessment of non-price criteria when there are a number of similar options available in the marketplace.

EGMA, through its collaborative participation in state-wide energy efficiency initiatives, also employs appropriate analytical tools to evaluate demand-side resource options. In particular, the Company employs a cost-effectiveness screening model developed through a collaborative process. The evaluation of demand-side resources is based on an assessment of avoided energy costs to ensure that supply and demand-side resources are evaluated consistently to yield an overall least-cost resource plan.

B. Description of the Current Resource Portfolio

1. Overview of Supply-Side Resources

EGMA's upstream supply and capacity portfolio is comprised of a multitude of supply, transportation, and storage contracts. These contracts are grouped into upstream capacity resource paths, which flow gas from the supply source to the Company's city gates. EGMA's upstream firm capacity paths are listed in Appendix 2 and show all of the Company's firm transportation, storage, and supply resources. EGMA's long-term contracts are listed in Appendix 1, Table G-24 and their peak deliverability is shown below in Table I-1.

Table I-1
EGMA Firm Portfolio Resources

	Maximum Daily Transportation Quantity MMBtu / Day (MDQ)
Algonquin Gas Pipeline	
AGT Firm Capacity with Flowing Supplies (1)	125,078
AGT Firm Capacity from Storage (2)	54,458
AGT Firm Local Transportation Service (3)	20,000
AGT Delivered Supply (4)	33,000
Total Firm AGT Transportation	**232,536**
Tennessee Gas Pipeline	
TGP Firm Capacity with Flowing Supplies (5)	132,981
TGP Firm Capacity from Storage Fields (6)	53,696
Total Firm Delivery Tennessee	**186,677**
Liquefied Natural Gas	
LNG	112,500
LPG	40,000
	152,500
System Total Capacity	
Maximum Peak Day Deliverability	**571,713**
Maximum Annual Firm Deliverability	

(1) Includes TETCO LH, AGT AIM, AGT Centerville and the NUI Exchange.
(2) Includes TETCO storage, Eastern Gas storage, and portion of Enbridge storage.
(3) Beverly receipt capacity
(4) Peaking contracts to the AGT G Lateral.
(5) Includes TGP LH, TGP Niagara, TGP Dawn via TCPL-PNGTS and the NUI Exchange.
(6) TGP FSMA, National Fuel, a portion of Enbridge Storage

Although EGMA has three separate service divisions, for planning purposes, the Brockton Division is separated from the Springfield and Lawrence Divisions because it is primarily served by Algonquin, and the Springfield and Lawrence Divisions are primarily served by Tennessee.

The ability to transfer supplies between divisions is limited, with the only capability being the transfer of up to 6,000 Dth per day to Brockton via a physical interconnect from Tennessee at the Brockton Sales, Massachusetts gate station. Also, EGMA is able to exchange additional volumes on an as-needed basis during the winter months (November – April), with Northern Utilities, Inc. ("Northern"), which allows the Brockton, Lawrence and Springfield Divisions to receive in total approximately 12,000 Dth of supply when needed.

EGMA's supply-side resources are grouped into three categories: supply, storage, and peaking. Supply and storage resources are delivered by transportation contracts held on various upstream pipelines. Each group is discussed in greater detail below.

Supply Resources

EGMA acquires firm supply on a seasonal, monthly and daily basis through a combination of term and spot purchases. The majority of EGMA's firm gas supply is sourced from the Marcellus Shale ("Marcellus"), located on the Millennium, Texas Eastern and Tennessee pipelines as well as supplies delivered from the Dawn Hub into the TransCanada pipeline systems. In the summer, the Texas Eastern and Tennessee pipelines are used primarily for transporting supply to storage facilities. Purchases for storage refill are normally made on a spot basis or by utilizing asset management agreements for ratable storage refill.

For the most part, supply resources are purchased under the North American Energy Standards Board ("NAESB") gas supply contract. This NAESB contract includes standard provisions which the parties supplement with special provisions.

Regarding the structure for supply resource commodity purchases, LDCs can determine the least-cost commodity resource purchase on a day-to-day basis by gathering market intelligence via electronic trading platforms such as Intercontinental Exchange ("ICE") as well as phone and e-mail solicitations. In any case, EGMA would only solicit and trade with those counterparties with which the Company currently has an active NAESB base contract.

EGMA's portfolio diversity includes supply points from the U.S. Gulf Coast, Appalachia and Canada. Consequently, EGMA's ability to purchase commodity on a daily basis, from diverse locations, provides EGMA's customers with not only reliability, but the flexibility to adjust to changing customer demand and market conditions.

TGP Supply Portfolio and Contract Paths

Tennessee Contract FTA 5173 is EGMA's legacy long -haul TGP system transportation contract. It has a MDQ of 12,748 Dth and provides access to the TGP traditional supply areas and the Marcellus production area. It delivers to Springfield and Lawrence and during the summer season to the Company's TGP storage contract FSMA 5178. EGMA generally purchases the TGP supplies and the manages the associated transportation contract.

The TGP FTA 5291 and FTA 39741, with MDQs of 6,171 Dth and 4,081 Dth, respectively provide transportation from the TGP Niagara interconnection with TransCanada Pipeline (TCPL) to Springfield and Lawrence. EGMA generally purchases supplies at Niagara and manages the associated transportation contracts with a competitively bid annual AMA contract.

EGMA has three contracts that receive gas at the TGP Dracut, MA interconnection with PNGTS[64]. These include TGP FTA 98775 (MDQ of 6,100 Dth) that delivers gas to Northampton in the Springfield division; FTA 48427 (MDQ of 17,000 Dth) that delivers gas to the Tewksbury lateral in the Lawrence division (a separate Tewksbury lateral contract FTIL 362252 delivers the gas to the EGMA Andover gate station); and FTA 330904 (MDQ of 96,400 Dth) that delivers gas to both Springfield and Lawrence.

Several different contracts deliver gas to Dracut. These include three PNGTS contracts, two of which (PNGTS 208540 and PNGTS 233301) can deliver a total of 59,800 Dawn purchase supplies and one of which (PNGTS 208540) delivers 16,000 Dth of Dawn storage supplies. In addition to this, there are two Repsol peaking supply contracts, that can deliver a total of 47,000 Dth to Dracut. TGP FTA 330904 is used for moving these Dracut receipts to EGMA's city gates.

[64] The TGP FTA 330904 contract receives gas from PNGTS at Dracut and Haverhill. The Haverhill receipts are delivered to Lawrence, while the Dracut receipts are delivered to Springfield. The Dracut interconnection was constructed when the joint PNGTS and Maritimes and Northeast project was constructed, while the Haverhill interconnection is with Granite State Transmission and was used to deliver TGP system supplies to Northern Utilities prior to Order 636. For the purposes of this report, we will use Dracut as the receipt point for the TGP 330904 contract.

This includes the Enbridge storage of the 16,000 Dth/day, which is a part of Enbridge storage AMA agreement, described below with the Storage AMAs. Part of the FTA 330904 contract is dedicated as part of the Dawn Purchase AMA contract[65], and part of the contract is used to transport winter season Repsol peaking supplies. The FTA 98775 (the Northampton contract) and FTA 48427 (the contract that feeds the Tewksbury lateral) are Company managed contracts and not part of any AMAs.

Algonquin Supply Portfolio and Contract Paths

The Texas Eastern CDS 800462 contract provides EGMA's Brockton division access to the TETCO long haul supply area and the Marcellus production area. The final deliveries to Brockton are delivered by Algonquin legacy contracts.[66] The TETCO contract has a MDQ of 36,369 Dth and is also used to refill the TETCO storage contracts and the EGTS storage contract during the injection season. EGMA generally purchases TETCO long haul supplies and manages the AGT transportation contracts with a competitively bid annual AMA contract.

The Algonquin AFT-1 510352 contract provides 48,000 Dth of transportation from the AGT interconnection with Transco in Centerville, NJ to the Brockton division. EGMA generally purchases gas at Centerville and manages the transportation contract with a competitively bid annual AMA contract.

The Algonquin AFT-1 510066 contract provides 20,000 Dth of transportation from the AGT Beverly, Ma interconnection with Maritimes & Northeast Pipeline. This contract was part of the AGT Hubline project that was designed to deliver gas from offshore at Canaport, New Brunswick. EGMA does not have any upstream capacity at Beverly. Because of the relatively high price of supplies at Beverly, EGMA uses this contract as part of a winter supplemental supplies.

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65 The Dawn purchase AMA provides the opportunity to deliver 12,000 Dth to Northern Utilities as part of an exchange agreement. On days when EGMA delivers 12,000 Dth to Northern, Northern delivers an equivalent amount of gas to EGMA's AGT and TGP divisions using Northern's own capacity to EGMA.

66 The Algonquin legacy contracts do not provide a one for one direct tie to the TETCO contracts. The more recent AGT contracts were originally certificated as part of an incremental project where the AGT contracts were tied to specific upstream contracts. The legacy AGT contracts are not tied to specific TETCO contracts.

The Algonquin AFT-1 AIM contract provides 30,000 Dth of transportation from the AGT interconnection with Millennium Pipeline in Ramapo, NY to Brockton. The Millennium Pipeline provides access to the Marcellus production area in eastern PA. EGMA also has a 15,000 Dth contract with Millennium, contract FT 217524, to supply half of the Company's AIM capacity supplies. EGMA generally purchases and manages the Millennium capacity with the Ramapo purchases under a competitively bid annual AMA contract.

Tennessee Storage Resources and Contract Paths

For the Springfield and Lawrence Divisions, EGMA has storage service contracts with Tennessee, National Fuel and Enbridge. The Tennessee and National Fuel facilities are located in western Pennsylvania, and the Enbridge facilities are located near Dawn, Ontario.

The TGP FSMA storage contract has a MDWQ of 19,755 Dth, annual storage capacity of 1,222,594 Dth, and a MDIQ of 8,151 Dth. It is in Ellisburg, PA. Two TGP FTA contracts provide transportation to Springfield and Lawrence, FTA 5293 (MDQ 12,547 Dth), which receives gas only from the TGP FSMA contract, and FTA 5196 (MDQ 15,375 Dth), which receives 5,500 Dth from the TGP FSMA contract and 9,875 Dth from the National Fuel FSS contract discussed below. EGMA generally manages the FSMA storage contract, related injection supplies, and transportation of FSMA withdrawals.

The National Fuel storage contract has a MDWQ of 10,000 Dth, annual storage capacity of 1,100,000 Dth, and MDIQ of 6,699 Dth. Gas for injection is delivered by a National Fuel FST transportation contract (N12604) that receives gas from TGP at East Aurora, NY. Gas withdrawn from the FSS contract is transported by the same FST contract to the TGP FTA 5196 contract at Rose Lake, PA, which has a maximum daily receipt point quantity of 9,875 Dth (plus fuel). EGMA generally manages the National Fuel storage contract with an AMA contract that provides for injection purchases at the TGP interconnection with TCPL in Niagara at a Niagara based index, transportation on TGP to the National Fuel FST contract for injection into the FSS contract, withdrawals from FSS, transportation on FST to the TGP 5196 contract for ultimate delivery to Springfield and Lawrence.

The Enbridge LST166/143[67] storage contract is in Dawn, Ontario. It has a MDWQ of 16,000 Dth, annual storage capacity of 1,600,000 Dth, and a MDIQ of 8,000 Dth. Under the AMA contract, injections are based on the monthly summertime Dawn index. The contract path includes: withdrawals from the LST contract, transportation on TCPL contract 63397 (MDQ 16,000 Dth) from Dawn to PNGTS at East Hereford, Quebec/Pittsburg, NH: transportation on PNGTS contract 208540 (MDQ 16,000) to the interconnection with TGP at Dracut, MA; and transportation on TGP FTA 330904 (MDQ 96,400 Dth, with only 16,000 Dth dedicated to this AMA contract) with final deliveries to Springfield. The AMA delivered MDQ is 16,000 Dth even though the pipeline fuel losses along the contract path would reduce the delivered quantity if the Company were to manage the contract by itself. The annual AMA contract is competitively bid.

The Enbridge LST165/144 storage contract is also located in Dawn, Ontario. It has a MDWQ of 26,500 Dth, annual storage capacity of 1,820,000 Dth, and a MDIQ of 10,000 Dth. Injections are based on the monthly summertime Dawn index during the injection season. The contract path includes: withdrawals from the LST contract, transportation on Union contract M12204 (MDQ 26,352 Dth) from Dawn to TCPL at Parkway, Ontario: transportation on TCPL contract 63398 (MDQ 26,063 Dth) from Parkway to the Iroquois interconnection point at Waddington, NY; and transportation on IGT contract 182003 (MDQ 28,840) to the interconnection with TGP at Wright, NY. At Wright, two TGP contracts are used to deliver to EGMA's gate stations. The first contract is TGP FTA 95349 (MDQ 9,774 Dth) which delivers to both Springfield and Lawrence. The second contract is TGP FTA 41098 (MDQ 18,733 Dth) which delivers to the TGP/AGT interconnection at Mendon, MA. The final leg of the Brockton division deliveries of the storage contract is Algonquin AFT-1 93001F (MDQ 18,490). The AMA provides for the full delivery of 9,774 Dth to Springfield and Lawrence and 18,490 Dth to Brockton even though the upstream pipeline MDQs and pipeline fuel losses along the contract path would reduce

[67] The Company requested and the Department granted approval for renewal of the Enbridge storage contracts LST143 and LST144 in D.P.U. 21-118. These contracts were renewed and the new contract numbers effective March 31, 2024 will be LST166 and LST165.

the delivered quantity if the Company were to manage the contract by itself. This annual AMA contract is also competitively bid.

Algonquin Storage Resources and Contract Paths

For the Brockton Division, EGMA has storage service contracts with Texas Eastern, Eastern Gas Transportation and Storage (formerly Dominion Transmission), and Enbridge storage as mentioned above with the TGP related Enbridge LST165/144 contract.

The Texas Eastern SS-1 contract 400193 has a MDWQ of 22,819 Dth, annual storage capacity of 1,588,950 Dth, and a MDIQ of 8,168 Dth. This contract is traditionally Company managed because it is a very flexible contract, providing no-notice service which is essential for providing balancing services for the Brockton Division. Spot gas from the TETCO Marcellus production area is injected during the summer. Withdrawals are delivered under the SS-1 contract directly to AGT contracts at Lamberville, NJ. EGMA generally uses its AFT-E no-notice contract for transportation to the Brockton gate stations to take full advantage of the no-notice service,

The Texas Eastern FSS-1 contract 400502 has a MDWQ of 1,056 Dth, annual storage capacity of 63,360 Dth, and a MDIQ of 326 Dth. This contract is also traditionally Company managed because it is a flexible contract, although it doesn't provide the same level of no-notice service provided by the SS-1 contract.[68] Spot gas from the TETCO Marcellus production area is injected during the summer. Withdrawals are delivered under CDS contract 800414 (MDQ 1,056 Dth) to AGT contracts at Lamberville, NJ. EGMA generally uses its AFT-E no-notice contract for transportation to the Brockton gate stations to take advantage of the CDS and AFT-E no-notice flexible service.

The EGTS Storage contract GSS 600002 has a MDWQ of 14,758 Dth, annual storage capacity of 1,441,753 Dth, and a MDIQ of 8,010 Dth. It has an "incomplete" contract path that compels EGMA to use an AMA contract to manage the storage and related transportation contracts. The specific terms of the AMA contract will vary from year to year, however the AMA

[68] The FSS-1 contract does not offer the same level of no-notice serve as the SS-1 contract, but the withdrawals are transported under no-notice contracts which provide the maximum amount of flexibility available under the FSS-1 Rate Schedule.

storage contract is tied to the Company's' TETCO FT-1 800382 contract (MDQ 4,235 Dth), the Transco FT 9239453 contract (MDQ 1,254 Dth), and flows on part of AGT AFT-1 93201AC (2,500 Dth) that has the Centerville receipt point tied to the Transco 9239453 contract), and part of AFT-1 94501 contract (currently 9,500 Dth). The current AMA contract delivers a total of 12,000 Dth to the Brockton division. EGMA manages the injections, the storage capacity and the transportation contracts with a competitively bid annual AMA contract. The Asset Manager is responsible for providing the "missing" transportation capacity.

Peaking Resources

On-system peaking resources are those that EGMA controls within its service territory and are comprised of LNG and propane facilities located in each service territory. The Company has retired its former West Springfield propane facility since its last Forecast and Supply plan. These on-system resources are listed in Appendix 1, Table G-14.

EGMA has multi-year contracts for off-system peaking supply, such as from Constellation Energy (owner of the Distrigas LNG facility),[69] and Repsol,[70] which stores LNG in New Brunswick, that can be vaporized and delivered into the New England markets. Decisions to procure seasonal peaking supplies are driven by an evaluation of design winter deficiencies that may be identified within the portfolio.

2 Current Contract Status

This section describes the Company's pipeline transportation and storage contracts, their respective termination dates, their respective notification dates, and the steps that EGMA will take in response to the pending termination dates. Because the Company requires all of its current contracts and still requires the purchase of winter season supplemental supplies to meet current

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[69] CMA used a one-year contract to provide this service for the winter of 2019-20. EGMA filed for D.P.U. approval of a three-year, 8,000 Dth/day winter peaking service contract with Constellation LNG on January 29, 2021 in D.P.U. 21-09, which was approved on August 16, 2021. This contract expires on March 31, 2024.

[70] CMA filed on November 2, 2017 for Departmental approval of the TGP Zone 6 to Zone 6 contract for 96,400 Dth/day, 14,300 Dth/day of PNGTS Portland Express Project (with upstream capacity on Union and TCP)L, and two ten-year peaking services contracts with Repsol for a total of 47,000 Dth/day. The contracts were approved in D.P.U. 17-172 on May 31, 2018. This contract expires on March 31, 2028.

and expected future requirements, the Company is planning to renew all of its pipeline contracts when the contract notification dates arise. Table G-24 in Appendix 1, provides the MDQs, the Primary Term Expiration Dates, the current termination dates, termination notification dates, and whether the Company is requesting Departmental approval of the contracts in this proceeding. This section summarizes the renewal status of the contracts.

Algonquin Contracts:

The AGT legacy contracts (93001EC, 93201AC, 93401, 93001F, 94501, 510352) are scheduled to terminate October 31, 2025, with a notification date of October 31, 2024. The AGT Hubline contract 510066 is scheduled to terminate on 11/30/2025, and has a notification date of 11/30/2024. These contracts all are on evergreen status and renew automatically. The contracts are essential and have no practical alternative. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these 1 year extensions for the duration of the planning horizon of this filing.

Algonquin AIM contract 510804 was approved in D.P.U. 13-158. It does not terminate until 2032. This contract provides for a 1 year notice period before termination to extend the contract for 5 or 10 years which does not occur within two years of this filing. Therefore, the Company is not requesting an extension of this contract in this filing.

Texas Eastern Contracts:

The TETCO legacy contracts (800462,800414,800382) are scheduled to terminate October 31, 2029, have a notification date of October 31, 2024, and are on evergreen status for 1 year renewal. They are automatically renewed. The contract is essential and has no practical alternative. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these 1 year extensions for the duration of the planning horizon of this filing.

TETCO storage contract (400502) is a core storage contract serving the Brockton area is scheduled to terminate 4/30/2029 and has a notification date of 4/30/2024. It is on evergreen status for 1 year renewal. The contract is essential and has no practical alternative. The contract can automatically be renewed. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these extensions for the duration of the planning horizon of this filing.

TETCO storage contract (400193) is a core storage contract serving the Brockton area is scheduled to terminate 10/31/2029 and has a notification date of 4/30/2024. It is on evergreen status for a 5 year renewal which will then renew ever year for 1 year. The contract is essential and has no practical alternative. The contract can automatically be renewed. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these extensions for the duration of the planning horizon of this filing.

Tennessee Contracts:

TGP FTA 5173 (Longhaul) -The longhaul contract provides transportation from the TGP production areas to the Company's gate stations. This contract is scheduled to terminate on 10/31/2028 and the notice date is 10/31/2027. It is on evergreen status which TGP requires 5-year contract extensions at that time. The contract is essential and has no practical alternative. The contract can automatically be renewed. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these extensions for the duration of the planning horizon of this filing.

TGP FSMA 5178- This contract is the core TGP storage contract serving Springfield and Lawrence. This core storage contract is scheduled to terminate 10/31/2028 and has a notification date of 10/31/2027. It is on evergreen status which TGP requires 5 -year contract extensions. The contract is essential and has no practical alternative. The contract can automatically be renewed. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these extensions for the duration of the planning horizon of this filing.

TGP FTA 5293 – This contract provides transportation from the TGP FSMA storage contract to the Company's Springfield and Lawrence divisions. This core storage transportation contract is scheduled to terminate 10/31/2029 and has a notice date of 10/31/2028. It is on evergreen status which TGP requires 5-year contract extensions at that time. The contract is essential and has no practical alternative. The contract can automatically be renewed. Pursuant to

D.P.U. 16-40 the Department is not required to approve the renewal of these extensions for the duration of the planning horizon of this filing.

TGP FTA 5291 and FT 39741 (Niagara FT), have renewal notices of 03/31/24 and contract termination dates of 03/31/25. They are on evergreen status and require one year notification prior to extension. These contracts are essential and have no practical alternative. The contracts can be automatically renewed. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these extensions for the duration of the planning horizon of this filing.

TGP FTA 48427 (Dracut to Tewksbury) contract has a renewal notice date of 10/31/24 and an expiration date of 10/31/25. It is on evergreen status and requires one year notification prior to extension. The contract is essential and has no practical alternative. The contract can automatically be renewed. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these extensions for the duration of the planning horizon of this filing.

TGP FTA 41098 and FTA 95349 have a renewal notice dates of 10/31/26 and contract expiration dates of 10/31/27. These contracts provide transportation from IGT to AGT at Mendon and to Springfield and Lawrence. These contracts are on evergreen status and require one year notification prior to extension. These contracts are essential and have no practical alternative. The contracts can automatically be renewed. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these extensions for the duration of the planning horizon of this filing.

TGP contracts FTA 5196 (Storage FT), FTA 98775 (Dracut to Northampton), and FTA 330094 (Dracut to Springfield and Lawrence) are on evergreen status and require one year and two year notification prior to extension. These contracts are essential and have no practical alternative. The contracts can automatically be renewed. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these extensions for the duration of the planning horizon of this filing.

TGP FTIL 362252 Tewksbury Lateral- This is a one year contract that took effect 11/1/2021 with a MDQ of 14,000 Dth and receives supplies from TGP 48427 contract with a MDQ of 17,000 dth. The Company will look to renew this contract annually for one year each year and Department approval is not required.

<u>PNGTS Contracts and related Union and TCPL contracts</u>

The Company has three contracts with PNGTS. The first contract, 208540, transports storage gas from the Enbridge LST166/143 contract via the TCPL contract 63397. The PNGTS contract is scheduled to terminate in 2032. Therefore, the Company is not requesting an extension of this contract in this filing. The related TCPL 63397 contract is scheduled to terminate in 10/31/26 with a renewal notice of 10/31/25. The contract is on evergreen status and requires one year notification. It is essential and has no practical alternative. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these extensions for the duration of the planning horizon of this filing.

The other two PNGTS contracts, 208535 and 233301 transport gas under the PXP project. The related Union Gas contract M12292 and TCPL contract 64198 transport the gas from the Dawn Hub to PNGTS for ultimate delivery to TGP at Dracut. All the PNGTS contracts and related Union and TCPL contracts including the downstream TGP contract 330904 that delivers the Canadian supplies to EGMA's city-gate were approved by the Department in D.P.U.17-172. The two PNGTS contracts, the Union(M12292), and the TCPL(64198) contracts all terminate on October 31, 2040. The Company is not requesting an extension of these contracts.

The Union Gas contract M12204 transports gas from Enbridge Storage (LST165/144). The related TCPL contract 63398, delivers into the IGT system. Contract M12204 has a termination of 10/31/2026 and a two year notice date of 10/31/2024. It is essential and has no practical alternative. EGMA requests that the Department approve the renewal of Union contract M12204

<u>Enbridge Storage Contracts:</u>

Enbridge storage contract LST143 for 16,000 Dth/day of Enbridge storage deliverability and 1,600,000 Dth of annual storage capacity in the Dawn Ontario region went into service on April 1, 2018, and will expire on March 31, 2024. The Department approved the renewal of the contract in D.P.U. 21-118. The Enbridge storage contract LST144 for 26,500 Dth/day of deliverability and 1,820,000 Dth of annual storage capacity went into service April 1, 2016 and will expire on March 31, 2024. The Department approved the renewal of the contract in D.P.U. 21-118. The Company negotiated an extension of these contracts through March 31, 2026 (now contracts LST 166/165). The continuation of the Enbridge storage contracts, in conjunction with the recently approved PXP project which provides access to substantial amount of flowing gas at Dawn, maintains a good balance between flowing supplies and seasonal storage for the EGMA portfolio. EGMA will conduct a request for proposals for similarly structured storage contracts to the Dawn receipt points of its TCPL contracts. As in D.P.U. 21-118, the Company requests the Department to approve the renewal of the Enbridge storage contracts through March 31, 2026.

National Fuel Storage Contracts:

The National Fuel FSS contract O12603, National Fuel FST storage transportation contract N12604 are scheduled to terminate March 31, 2025, and have a notification date of March 31, 2024. They are on evergreen status. The contracts are essential and have no practical alternative. They can be automatically renewed. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these 1 year extensions for the duration of the planning horizon of this filing contracts. The National Fuel storage gas is delivered by TGP to Springfield and Lawrence.

Transcontinental Contracts:

Transco contract 9239453 is part of the contract path to deliver storage gas from the Eastern Gas Transmission & Storage (formerly DTI) GSS storage contract to the Brockton Division. It is scheduled to terminate October 8, 2025, with a notification date of October 8, 2024. The contract is on an evergreen status. The contract is essential and has no practical alternative. This contract can automatically be renewed. Pursuant to D.P.U. 16-40 the Department is not required to approve the renewal of these 1-year extensions for the duration of the planning horizon of this filing.

Iroquois Contracts:

The Iroquois contract RTS 182003 provides transportation for the Enbridge storage contracts from the IGT interconnection with TCPL in Waddington, NY to its interconnection with TGP in Wright, NY. Without the IGT link, the storage gas could not be delivered to the related

TGP contracts and could not ultimately be delivered to Springfield, Lawrence, or Brockton. This contract is essential and has no practical alternative. The contract is due to expire on October 31, 2027, with a renewal notice of 10/31/2026. Because the notification date does not occur within two years of this filing, the Company is not requesting an extension of this contract in this filing.

Millennium Contract:

EGMA has entered into contract 217524 which will expire on March 31, 2034. This contract is part of a path that delivers purchased supply to EGMA city gate, while also allowing EGMA to directly access Marcellus supply. Because the notification date does not occur within two years of this filing, the Company is not seeking Department approval of its renewal in this filing.

Granite State Gas Transportation Contract:

The Company extended contract No. 26-001-FT-1, on August 18, 2023. The new contract is effectively an extension of the previous contract No. 22-001-FT-1. EGMA has a year-to-year physical exchange agreement with Northern Utilities. Through this exchange agreement, Northern Utilities delivers 12,000 Dth/day directly to the EGMA city gates in Lawrence, Springfield and Brockton divisions. In exchange, EGMA delivers 12,000 Dth/day to the Northern Utilities city gate using this Granite State Gas Transmission (“GSGT”) FT-1 capacity. EGMA utilizes flowing supply from PNGTS to fill this GSGT capacity. The contract is for 1 year or less and therefore EGMA is not seeking Department’s approval.

Eastern Gas Storage Contracts:

Eastern Gas (Formerly DTI) gas storage contract 600002 is scheduled to terminate March 31, 2026, and has a notification date of March 31, 2024. The Department approved an extension of this contract in the prior F&SP D.P.U. 21-118 and the Company anticipates extending this contract in 2024 for up to 4 year term due to Eastern Gas new renewal policy. At that time the notification date will be 03/31/2026 and the term date will be 03/31/2028 The contracts are essential and have no practical alternatives. Consistent with D.P.U. 21-118, EGMA is seeking approval from the Department for the extension of this contract for up to a 4 year term.

On-System Peaking:

The Company continues to review the utilization of propane in its portfolio as part of the EGMA Safety Assessment and is in the process of replacing the LNG storage tanks at the Lawrence and Marshfield sites as part of the EGMA Safety Assessment. EGMA will continue to evaluate the operational capabilities of on-system peaking facilities as each facility continues to age and the operational requirements of the Company's distribution system continue to change. Should the results of ongoing analyses suggest a change in the daily and/or seasonal capability of any of EGMA's peaking facilities, EGMA will provide the updated capabilities within the F&SP process or other appropriate filing with the Department.

Peaking Supply:

EGMA has two transaction confirmations for LNG supplies from Repsol's Canaport LNG terminal for delivery on Tennessee capacity. A 30-day peaking supply for up to 32,900 Dth/day and a 40-day peak supply for up to 14,100 Dth/day are both contracted through March 31, 2028. These were approved by the Department in D.P.U. 17-172. Additionally, the Company entered into a contract with Constellation LNG LLC which provided for the firm delivery of up to 8,000 Dth/day to Company receipt points on AGT's Line G for the winter season. This contract is due to expire on March 31, 2024. The Company is currently in negotiations with CLNG regarding term supplies which will be submitted for approval in a separate filing. The Company will be assessing its future supply resources for the AGT G lateral and other locations as these contracts terminate during the forecast period.

B. Analyses Utilizing SENDOUT®

In order to assess the cost implications of various resource alternatives, EGMA performs optimization analyses using SENDOUT®. EGMA augments these cost analyses with assessment of non-cost characteristics in order to support its various resource decisions. Also, SENDOUT® is used to assess the adequacy of the resource portfolio under different levels of firm customer requirements.

This section of EGMA's Plan presents current SENDOUT® results based on its long-range forecast of requirements, existing resources and potential new supply resources. The results of these and recent analyses of the cost-effectiveness of potential EE measures form the basis of the Company's present Action Plan.

The SENDOUT® model is a linear programming software package designed for LDCs to optimize the cost of serving demand while ensuring reliable service to firm customers. Specifically, SENDOUT® incorporates the monthly demand forecast, converts this forecast into a daily interval, and then satisfies daily demand by utilizing the lowest cost resources from among those specified in the available network. EGMA's model includes limitations on the withdrawal of storage and peaking facilities to ensure that these assets are available throughout the heating season as one way to ensure reliable service to firm customers.

SENDOUT® assumes that all demand costs are fixed and all supplies are optimized based on variable costs. However, SENDOUT® can evaluate certain selected resources on a total cost basis. This evaluation is referred to as the Resource Mix option, and can be used to test whether a new contract should be entered into or whether an existing contract should be renewed. The Resource Mix option can also "size" a contract when given a maximum and minimum range from which to select. SENDOUT® is capable of handling several supply, transportation, and storage resources placed into the Resource Mix at one time.

EGMA utilizes SENDOUT® to test the adequacy of its resource portfolio, including any required incremental resources, under various design conditions. As described earlier, EGMA's design conditions include design day, design winter and cold-snap weather conditions.

EGMA's analyses, under a variety of demand scenarios, indicate that the portfolio is sufficient to satisfy EGMA's base case firm demand without the acquisition of incremental resources during the forecast period. The adequacy of the portfolio is due, in part, to the growth of EGMA's firm requirements under its base case scenario. This level of growth is a function of the projection of declining NUPC, somewhat dampening the load growth associated with the impact of projected customer growth.

It is important to note that the adequacy of the Company's portfolio to satisfy firm demand under the base and high case scenarios throughout the five-year forecast period (through October 2028), is in part due to EGMA's plan to acquire capacity to attain this portfolio adequacy.

Detailed results showing the resources utilized to meet firm customer requirements under each of the demand growth scenarios are provided in accompanying appendices. Appendix 1, G-22 Tables, provides the winter and summer dispatch results for the base, and high demand growth cases based on normal year requirements. Appendix 1, G-23 Tables, provides the winter and summer dispatch results for the base, and high demand growth cases based on design year requirements.

Table I-2
EGMA Gas Normal Year Adequacy (BBTU)
Base Case

Gas Year	2023/2024	2024/2025	2025/2026	2026/2027	2027/2028
Requirements					
Sendout	46,882	46,391	46,912	48,112	49,051
Injection	9,045	9,168	9,309	9,366	9,326
Total	55,926	55,559	56,221	57,478	58,377
Resources					
Pipeline	46,396	45,894	46,403	47,557	48,488
LNG/LPG Trucking	649	612	677	723	729
Storage Withdrawals	8,232	8,389	8,464	8,476	8,431
LNG Withdrawals	649	663	677	723	729
LPG Withdrawals	0	0	0	0	0
Other Supplies	0	0	0	0	0
Total	55,926	55,559	56,221	57,478	58,377

Note: Annual normal year figures are on a Gas Year (November through October) basis, not Calendar Year basis.

Table I-3
EGMA Gas Design Year Adequacy (BBTU)
Base Case

Gas Year	2023/2024	2024/2025	2025/2026	2026/2027	2027/2028
Requirements					
Sendout	51,785	51,291	51,803	53,069	54,068
Injection	9,475	9,623	9,791	9,883	9,900
Total	61,259	60,914	61,594	62,952	63,968
Resources					
Pipeline	50,807	50,290	50,778	51,932	52,887
LNG/LPG Trucking	1,129	1,105	1,181	1,290	1,322
LNG Withdrawals	1,108	1,134	1,160	1,266	1,301
LPG Withdrawals	21	21	21	21	24
Storage Withdrawals	8,184	8,353	8,443	8,426	8,412
Other Supplies	11	11	12	17	21
Total	61,259	60,914	61,594	62,952	63,968

Note: Annual design year figures are on a Gas Year (November through October) basis, not Calendar Year basis.

Incremental Resources are not required in a Normal Year in either the Base Case or High Case Growth Scenarios. However, in a Design Year, regardless of growth, and in the Cold Snap Scenarios, discrete upstream incremental pipeline and/or supply resources are required in most years of the plan. The Company would expect to cover any Incremental Resource needed with upstream or citygate supply, or a pipeline expansion should one become available and was selected by the Company's planning process as least cost option and also approved in a separate by the Department. The Design Day Scenarios are outlined below in Tables I-4 through I-6.

Table I-4					
EGMA Gas Design Day Adequacy (BBTU)					
Base Case					
Gas Year	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Peak Day Sendout	521.1	520.4	522.7	531.2	538.4
Resources					
Pipeline	275.9	275.9	275.9	275.9	275.9
Storage Withdrawals	104.5	104.5	104.5	104.5	104.5
LNG Withdrawals	109.0	108.4	109.7	112.5	112.5
LPG Withdrawals	21.0	21.0	21.0	21.3	24.3
Other Supplies	10.7	10.5	11.5	17.0	21.2
Total	521.1	520.4	522.7	531.2	538.4
Low Growth Scenario					
Gas Year	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Peak Day Sendout	520.9	512.7	512.4	520.8	528.2
Resources					
Pipeline	276.0	275.9	275.9	275.9	275.9
Storage Withdrawals	86.5	85.4	85.9	87.9	90.0
LNG Withdrawals	69.0	69.0	69.0	69.0	69.0
LPG Withdrawals	89.5	82.4	81.6	87.9	93.3
Other Supplies	0.0	0.0	0.0	0.0	0.0
Total	520.9	512.7	512.4	520.8	528.2
High Growth Scenario					
Gas Year	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Peak Day Sendout	522.0	524.3	527.8	537.2	544.6
Resources					
Pipeline	276.0	275.9	275.9	275.9	275.9
Storage Withdrawals	109.6	108.9	110.4	112.5	112.5
LNG Withdrawals	21.0	21.0	21.0	22.3	25.6
LPG Withdrawals	104.5	104.5	104.5	104.5	104.5
Other Supplies	10.9	13.9	16.0	21.9	26.0
Total	522.0	524.3	527.8	537.2	544.6

Table I-5
Design Day Adequacy for High and Low Growth Scenarios (BBTU)

Scenario / Gas Year	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Sendout requirements-High	521.9	524.2	527.7	536.9	544.1
Sendout requirements-Low	520.9	512.7	512.5	520.7	528.1
Resources-High	511.0	510.3	511.8	515.1	518.3
Resources-Low	510.2	509.2	509.6	511.6	513.6
Citygate supplies-High	10.9	13.8	15.9	21.8	25.8
Citygate supplies -Low	10.7	3.6	2.9	9.1	14.5

Table I-6
EGMA Gas Design-Day Firm Requirements (BBtu)
Base Case

Year	Brockton	Lawrence	Springfield	Total
2023-24	289.2	85.3	146.6	521.1
2024-25	289.1	84.5	146.8	520.4
2025-26	290.0	84.8	147.8	522.7
2026-27	295.5	86.5	149.3	531.2
2027-28	299.7	87.9	150.8	538.4

Overall, EGMA is presently projecting a modest resource deficiency in the base case scenario, which will be served through a combination of peaking supplies, via an RFP process, and day-to-day spot supply. Also, as noted above, EGMA will be required to evaluate a number of important contract renewal decisions during the five-year planning horizon. These include capacity on Tennessee, Algonquin, Iroquois, National Fuel, Eastern Gas, Transco, TransCanada, Union, PNGTS, and TETCO. Appendix 1, Table G-24, highlights all contracts that terminate during the forecast period, terms and required notice dates for renewal, as well as indicating those contracts having an evergreen provision. Some of these contracts provide important primary delivery point capacity needed to maintain the reliability of EGMA's system.

As the decision time nears for each of these renewal decisions, EGMA will employ its resource planning process to establish the least-cost alternative, which may be renewal, replacement, reduction or termination of all of the existing resources, as explained in Section I, above. The Department will be notified of any long-term renewal decisions and, further, any new long-term capacity contracts, as may be required, will be filed with the Department, along with the appropriate support, for approval under G. L. c. 164, § 94A. In this F&SP, the Company requests specific approval to renew all contracts with renewal notice required within the two-year period from the filing of this document and also all contracts just outside of the two-year window with renewal dates November 1, 2025. These contracts are noted on Table G-24.

C. Evaluation of Demand-Side Resources

EGMA considers both supply and demand-side options on an equal footing. The evaluation of demand-side resources on a consistent basis with supply-side resources is accomplished through a separate screening process utilizing appropriate analytical tools. Avoided energy supply costs are the basis for determining the cost-effectiveness of alternative demand-side resources. In Massachusetts, the supply-side avoided costs utilized by all LDCs in their EE Plans are prepared on a regional basis and are updated biannually. The most recent regional avoided cost study is the Avoided Energy Supply Costs in New England: 2021 Report ("AESC 2021"), which was completed on March 15, 2021 and amended on May 14, 2021.

An EE program cost-effectiveness screening model is utilized to evaluate EE resources. The model incorporates an array of descriptive parameters, in addition to the avoided energy costs, to calculate the expected lifetime energy savings of EE measures. Screening is performed on a total-resource cost test basis as currently specified by the Department. The EE program is discussed further in Section II.

D. Non-Cost Analyses

In addition to a cost analysis, EGMA evaluates other attributes of potential resources, including reliability, flexibility and viability. This non-cost evaluation is accomplished through appropriate assessment techniques, and is integrated with cost-considerations in order to arrive at final resource decisions. EGMA will present a comprehensive analysis of both cost and non-cost considerations associated with available alternatives at the time the Company requests Department approval of any specific long-term resource option.

E. Operational Considerations

Although EGMA's F&SP is a comprehensive plan intended to reliably service the long term demands of its customers, EGMA nonetheless faces operational risks in the day-to-day management of its system. Some of these risks are inherent and quantifiable, such as the risk that the weather could be colder than design day or extends longer in duration than EGMA's planned cold snap. Other risks, however, are outside of EGMA's direct control. For example, several years ago, TGP installed an electric compressor to support the Northampton lateral. A failure of this singular compressor station due to electrical interruption or mechanical failure could lead to significant pressure drops on the Northampton lateral and potentially result in disruption of service to EGMA's customers.

Electric generation facilities are now the largest consumers of natural gas; larger than the natural gas LDC community. Electric generation facilities tend to burn their daily allotment of gas in a very short period of time, typically in less than a twelve-hour period. The increasing utilization of the natural gas system by electric generating facilities especially when taking gas in a non-ratable manner, when the natural gas system was designed for natural gas LDC usage, which is more consistent throughout the day, has resulted at times in very low instantaneous pipeline pressures. This threatens the overall viability of the natural gas system.

The increased demands resulting from (1) new electric loads attaching to the pipeline system without corresponding pipeline capacity and (2) new customers converting to natural gas have resulted in the natural gas pipeline system running consistently at or near design peak day levels. Several years ago, when there was more flexibility of available capacity in the pipeline system, TGP would restrict their pipeline at station 245, the entry point into Massachusetts (Zone 6). Now, due to the increased electric load, changing supply dynamics, and increased overall demand, TGP has been actively restricting their pipeline through every existing compressor station in Massachusetts, something never experienced before. EGMA's planning standards have not traditionally included a gate-by-gate specific supply/demand balance. EGMA's customers do not take supply on an evenly hourly basis and hourly take restrictions which the pipeline can institute require EGMA to acquire supply and/or capacity to meet these demands.

Additionally, when the pipeline runs consistently at or near its design day capabilities, there is a much greater risk that the pipeline system could experience a widespread interruption of service, due to the fact that the pipeline compressor stations are running at high utilization rates, and are therefore more prone to breakdown. When compressor stations breakdown, this causes overall lower system pressures and throughput. This may result in the pipeline cutting firm pipeline capacity, resulting in EGMA potentially using much more peaking resources than planned. When a compressor fails, it has the immediate effect of lowering pressures downstream of that compressor station and the pipeline is forced to cut flowing gas through that point. The net result is that EGMA must strive to maintain higher levels of on-system peaking resources in the event of pipeline curtailments.

F. Springfield Division – Reliability Plan

Prior F&SPs have discussed a reliability plan for the Springfield Division in detail. The reliability plan consists of four separate projects to accomplish the goal of enhancing the reliable, safe and continuous delivery of natural gas service to approximately 100,000 customers in the Springfield operating area. These projects will not impact Northampton or Easthampton and, as a result, the moratorium on natural gas service in Northampton and Easthampton will remain in place.

Three of these separate projects are part of a contract with TGP, which was approved by the Department in D.P.U. 17-172. The TGP contract entitles EGMA to 96,400 Dth of firm transportation capacity, which eliminates the need to rely on non-firm city-gate delivered supplies to manage supply deficiencies. Much of firm TGP capacity replaced much less reliable and interruptible capacity, significantly improving reliability of supply to customers in both the Springfield and Lawrence Divisions. This capacity became available on November 1, 2021. In addition, the TGP contract provides for increased delivery pressure of 300 psi at EGMA's Agawam point of receipt and an additional point of delivery from TGP.

First, pursuant to the Department-approved contract, TGP completed the Agawam Compressor Station Enhancement project, which consisted of upgrading equipment at TGP's existing compressor station to improve operating efficiency, deliver enhanced services and increase reliability to EGMA customers. Second, TGP completed the construction of the Agawam Two-Mile Pipeline Loop, which provides additional capacity and operational pressure that ensures reliable service on the western end of the Springfield operating area. The third project is the Longmeadow Supply Strategy Project in which TGP will install a new Point of Delivery ("POD") in the Town of Longmeadow. As part of this project, EGMA is seeking approval from the Energy Facilities Siting Board ("EFSB") to install facilities and new distribution piping from the new POD to its Bliss Street Station. The EGMA portion of this project is known as the Western Mass. Gas Reliability Project.[71] Completion of the Longmeadow Supply Strategy Project and the Western Mass. Gas Reliability Project will permit EGMA to enhance system reliability for 58,000 customers on both sides of the Connecticut River.

The fourth reliability project for the Springfield Division is the ConEd Transmission Line Replacement Project. This project will replace an 8,500 foot existing line with new pipe in Springfield to increase reliability and improve system flexibility.

These four separate projects are designed to provide for uninterrupted and reliable service to customers in the Springfield Division. EGMA will engage with the community in an open and transparent manner with respect to the construction of its projects. In addition, EGMA will conduct customer outreach and listening sessions for its Western Mass. Gas Reliability Project in advance of making a filing at the EFSB.

G. TAUNTON & ATTLEBORO – AGT LINE G ISSUE

The Company serves its Taunton and Attleboro areas (part of the Brockton Division) with capacity on AGT. The AGT lateral that serves these areas is AGT's Line G. For decades, the Company has used various AGT contracts to serve Taunton and Attleboro. Historically, EGMA's supply nominations have been made to an Allocation Point and AGT managed all city gates takes in on an aggregate basis accounting for all nominations to EGMA's Algonquin served market.

[71] EGMA filed a petition with the EFSB for approval of the Western Mass. Gas Reliability Project on May 26, 2022, EFSB 22-05, Petition of Eversource Gas Company of Massachusetts d/b/a Eversource Energy Pursuant to G.L. c. 164, § 69J for Approval to Construct and Operate a New Natural Gas Pipeline in the Town of Longmeadow and the City of Springfield.

EGMA has adequate capacity levels on AGT coupled with on-system peaking to meet projected total base case design day demand of its Brockton Division planning load and capacity exempt customers for the next winter season 2023-2024. AGT indicated that it may impose Line G specific operational flow orders, including the possibility of requiring 24-hour ratable deliveries or restricting deliveries to a specific point(s). The Company's contracts and system were not designed for such targeted pipeline operations. AGT's actions place the Company at risk of incurring penalties for over taking its contractual entitlements at Taunton and Attleboro, which has not been an issue until recently. Therefore, the Company received approval from the Department in D.P.U. 21-09 for the approval of three contracts to help serve the shortfall on Algonquin's G system. The first contract for 10,000 dekatherms (Dth) per day as an assignment of capacity from Neptune LNG, LLC. This contract expired on March 31, 2023. It has been replaced by a year supply deal through this winter. The second contract is a peaking agreement for 8,000 Dth per day of seasonal supply with Constellation LNG, LLC. This contract is due to expire in March 31, 2024. The third contract is a seasonal city-gate supply for 15,000 Dth per day with Direct Energy Business Marketing, LLC, which also expired in March 31, 2023. The Company will be assessing its future supply resources for the AGT G lateral as these contracts terminate during the forecast period as it cannot rely on the year-to-year availability of these other supplies.

These resources, coupled with the Company's existing portfolio, will help ensure adequate supply and capacity for the Brockton Division in total and will reduce the risk of potentially higher costs imposed by overtaking supplies at Taunton and Attleboro while under a Line G specific operational flow order. In addition to the above-described efforts, the Company continues to pursue additional supply resources for its Taunton and Attleboro area markets.

H. EVERETT MARINE TERMINAL

EGMA relies on the Everett Marine Terminal ("EMT") facility to provide reliable gas supply for their gas customers, particularly in the peak winter season. For the past several years, EGMA has entered into supply arrangements with EMT. These arrangements are a fundamental component of both EGMA and NSTAR Gas Company's fuel- supply resource plans and are vital to meet customer demand on winter-peak and design days.

In addition, EMT has served as a critical "reserve" gas resource to the region for decades and is uniquely positioned from a geographic perspective to provide seasonal peaking supply to the Eversource Companies for several reasons:

- EMT's location on the extreme east end of the pipeline network provides a supply source downstream of pipeline constraints on the coldest days of the year and serves as a critical backup in the event of a force majeure on one of the pipelines serving Massachusetts.

- EMT's 3.4 Bcf storage capacity near the largest load center of Massachusetts, has resulted in it being the largest natural gas storage asset in New England, which is a region without any underground storage fields.

- EMT's ability to make non-ratable hourly deliveries of large volumes of gas directly into the interstate pipeline network allows EMT to provide vital pressure support at the end of the system when needed, and its ability to shape deliveries to align with demand requirements of natural gas customers and interstate pipelines serving the Massachusetts, which have become increasingly stressed in the last several years.

- EMT's ability to contract for firm deliveries to meters on the highly constrained AGT G-Lateral via EMT's firm pipeline contracts with primary receipt at Everett provides the Eversource Companies with a critical supply source to manage G-Lateral hourly flow limitations and to enhance reliability and avoid pipeline penalties.

In addition to seasonal peaking supplies, the Eversource Companies have the ability to buy incremental gas from EMT on a spot basis. During extreme situations (e.g. Winter Storm Elliot December 2022, February 2023 cold snap, January 15th 2022 Algonquin Force Majeure), one of the first calls that the Eversource Gas Supply Team make is to EMT to determine if incremental supplies are available in the event that the supplies are needed.

VI EGMA'S ACTION PLAN

The Company expects to take advantage of roll-over rights for the majority, if not all, of its capacity contracts over the forecast period, thus maintaining the capacity the Company requires to provide reliable service to meet expected customer demands in the aggregate in all growth scenarios and weather conditions considered in this F&SP. EGMA will continue to closely monitor customer requirements so that it can take the necessary actions to ensure reliability if actual usage levels trend closer to the Company's forecast of high growth requirements. Further, as decision time nears for each of these contract decisions, the Company will determine the range of alternatives available in the marketplace, if any, and will employ its resource planning process to establish the least-cost alternative, which may be renewal or replacement of some or all of the existing resources.

The Company requests specific approval of the following contracts that have renewal notification dates that occur within two years of this filing:

> Eastern Gas Storage Renewal: Contract, No. 60002, is essential and the Company is requesting that the Department approve an extension for this contract for up to a 4 year term.
>
> Union Gas Transportation Capacity Renewal: Union Gas contract No. M12204 is up for renewal during the forecast period and the Company is seeking approval from the Department to renew contract M12204. This contract is a very valuable contract as is part of the transportation that delivers the Enbridge storage supply downstream to Portland and TGP contracts in order to deliver to EGMA city-gates.
>
> Enbridge Storage Capacity Renewal: EGMA has storage contracts, No. 166/143 and No. 165/144, with Enbridge. The Company is requesting to renew these contracts.

VII CONCLUSIONS REGARDING EGMA'S RESOURCE PLAN

The Company's F&SP, planning process and results have been subject to Department review in several previous filings pursuant to G.L. c. 164, § 69I. Also, requests for approval of long-term contracts have been subject to Department review in several filings pursuant to G.L. c. 164, § 94A. In this F&SP, the Company continues to utilize essentially the same planning process as has been employed since the time of its most recently approved F&SP, D.P.U. 21-118

EGMA has demonstrated that this F&SP meets the Department's standards for approval and is reviewable, appropriate and reliable. With respect to the Company's supply resource portfolio, the Plan indicates that EGMA's resource portfolio is adequate to meet the projected base case throughput requirements of its customers over the term of the forecast period, given the rollover and renewal of key existing pipeline transportation and storage capacity contracts and the acquisition of additional pipeline capacity. Further, EGMA's planning process achieves a least-cost portfolio, where resource decisions appropriately balance cost considerations with those related to the reliability and security of supply, contract flexibility and resource viability.

EGMA will carry out the elements of its Action Plan consistent with any guidance or direction from the Department. EGMA will file for Department approval long-term contracts related to specific resources in its portfolio that result from the application of the Company's resource planning process. EGMA has complied with the Department's order in D.P.U. 15-143 to request approval to renew any contract that is due to expire within two years of its F&SP filing. EGMA has specifically identified contracts that it is requesting approval to renew in Appendix 1 G-24. EGMA will rely on the results of this Plan as a guide in completing future resource analyses.

Table FA
MASS EFSC

Forecast Accuracy
Total Gas-Year Normalized Firm Planning Load (BBTU)
(Percent Difference)

Forecast Prepared For the Five-Years Starting:

Gas-Year 11/1-10/31	Actual Normalized Firm Planning Load	2016 (1)	2018 (2)	2021 (3)
2017-2018	46,557	46,594		
%CH		-0.1%		
2018-2019	47,526		48,365	
%CH			-1.7%	
2019-2020	47,037		48,191	
%CH			-2.4%	
2020-2021	48,739			47,334
%CH				3.0%
2021-2022	49,105			47,729
%CH				2.9%

(1) DPU 16-40
(2) DPU 18-47
(3) DPU 21-118

Table G-1
MASS EFSC

FIRM PLANNING LOAD BY CLASS
RESIDENTIAL WITH GAS HEATING

TOTAL HISTORICAL PLANNING LOAD (BBTU)

		ACTUAL		**NORMAL**	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2017-2018	267,467	18,395	7,600	18,439	7,364
2018-2019	271,524	19,375	7,292	18,783	7,485
2019-2020	277,482	17,505	7,852	19,020	7,538
2020-2021	281,212	17,683	6,853	20,143	7,223
2021-2022	283,906	17,962	6,825	19,842	7,214

TOTAL FORECAST PLANNING LOAD (BBTU)

		NORMAL		**DESIGN [2]**	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2023-2024	285,463	19,827	5,868	23,256	5,868
2024-2025	289,050	19,798	5,777	23,235	5,777
2025-2026	292,672	19,957	5,901	23,389	5,901
2026-2027	296,505	20,284	6,130	23,762	6,130
2027-2028	300,261	20,604	6,292	24,125	6,292

[1] Average customer counts calculated for the four quarters Q4-Q3 (October through September)
[2] Based on the aggregate ratio of design year to normal year

Table G-2
MASS EFSC

PLANNING LOAD BY CLASS
RESIDENTIAL WITHOUT GAS HEATING

TOTAL HISTORICAL PLANNING LOAD (BBTU)

		ACTUAL		NORMAL	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2017-2018	19,662	203	165	204	164
2018-2019	19,095	198	160	194	162
2019-2020	18,874	183	164	192	162
2020-2021	18,498	182	145	197	147
2021-2022	17,658	163	137	173	140

TOTAL FORECAST PLANNING LOAD (BBTU)

		NORMAL		DESIGN [2]	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2023-2024	16,568	167	111	167	111
2024-2025	16,005	158	105	158	105
2025-2026	15,441	153	103	153	103
2026-2027	14,878	149	101	149	101
2027-2028	14,315	144	98	144	98

[1] Average customer counts calculated for the four quarters Q4-Q3 (October through September)
[2] Based on the aggregate ratio of design year to normal year

Table G-3A
MASS EFSC

PLANNING LOAD BY CLASS
LOW LOAD FACTOR SALES

TOTAL HISTORICAL PLANNING LOAD (BBTU)

		ACTUAL		NORMAL	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2017-2018	21,495	6,074	1,900	6,079	1,797
2018-2019	21,880	6,167	1,814	5,970	1,873
2019-2020	22,070	5,338	1,836	5,843	1,748
2020-2021	22,154	5,663	1,751	6,507	1,878
2021-2022	22,184	5,897	1,732	6,560	1,864

TOTAL FORECAST PLANNING LOAD (BBTU)

		NORMAL		DESIGN [2]	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2023-2024	22,609	5,979	1,450	7,014	1,450
2024-2025	22,757	5,981	1,442	7,019	1,442
2025-2026	22,942	6,048	1,504	7,088	1,504
2026-2027	23,133	6,138	1,557	7,190	1,557
2027-2028	23,322	6,208	1,593	7,270	1,593

[1] Average customer counts calculated for the four quarters Q4-Q3 (October through September)
[2] Based on the aggregate ratio of design year to normal year

Table G-3B
MASS EFSC

PLANNING LOAD BY CLASS
HIGH LOAD FACTOR SALES

TOTAL HISTORICAL PLANNING LOAD (BBTU)

		ACTUAL		NORMAL	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2017-2018	4,241	1,531	1,504	1,536	1,502
2018-2019	3,928	1,425	1,459	1,411	1,468
2019-2020	4,074	1,468	1,220	1,536	1,214
2020-2021	4,115	1,304	1,359	1,382	1,376
2021-2022	4,248	1,565	1,609	1,643	1,632

TOTAL FORECAST PLANNING LOAD (BBTU)

		NORMAL		DESIGN [2]	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2023-2024	4,137	1,475	1,262	1,730	1,262
2024-2025	4,111	1,387	1,208	1,628	1,208
2025-2026	4,130	1,371	1,234	1,607	1,234
2026-2027	4,158	1,415	1,283	1,657	1,283
2027-2028	4,174	1,449	1,312	1,697	1,312

[1] Average customer counts calculated for the four quarters Q4-Q3 (October through September)
[2] Based on the aggregate ratio of design year to normal year

Table G-4
MASS EFSC

Planning Load BY CLASS
INTERRUPTIBLE

TOTAL HISTORICAL PLANNING LOAD (BBTU)

ACTUAL

Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**
2017-2018	0	0
2018-2019	0	0
2019-2020	0	0
2020-2021	0	0
2021-2022	0	0

TOTAL FORECAST PLANNING LOAD (BBTU)

NORMAL

Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**
2023-2024	0	0
2024-2025	0	0
2025-2026	0	0
2026-2027	0	0
2027-2028	0	0

Table G-4B
MASS EFSC

FIRM PLANNING LOAD BY CLASS
SPECIAL CONTRACTS

TOTAL HISTORICAL PLANNING LOAD (BBTU)

ACTUAL

Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**
2017-2018		
2018-2019		
2019-2020		
2020-2021		
2021-2022		

TOTAL FORECAST PLANNING LOAD (BBTU)

NORMAL

Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**
2023-2024		
2024-2025		
2025-2026		
2026-2027		
2027-2028		

Table G-4A
MASS EFSC

PLANNING LOAD BY CLASS
CAPACITY ELIGIBLE PLANNING LOAD

TOTAL HISTORICAL PLANNING LOAD (BBTU)

ACTUAL

Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**
2017-2018	5,361	3,295
2018-2019	5,992	3,352
2019-2020	5,750	3,199
2020-2021	5,598	3,394
2021-2022	5,762	3,378

TOTAL FORECAST PLANNING LOAD (BBTU)

NORMAL

Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**
2023-2024	6,477	3,134
2024-2025	6,355	3,056
2025-2026	6,318	3,189
2026-2027	6,545	3,352
2027-2028	6,699	3,476

Table G-4C-Sales
MASS EFSC

PLANNING LOAD BY CLASS
NEW PROJECT PLANNING LOAD

TOTAL HISTORICAL NEW PROJECT PLANNING LOAD (BBTU)

ACTUAL

Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**
2017-2018	0	0
2018-2019	0	0
2019-2020	0	0
2020-2021	0	0
2021-2022	0	0

TOTAL FORECAST NEW PROJECT PLANNING LOAD (BBTU)

NORMAL

Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**
2023-2024	0	0
2024-2025	0	0
2025-2026	0	0
2026-2027	0	0
2027-2028	0	0

Table G-4D
MASS EFSC

FIRM PLANNING LOAD BY CLASS
COMPANY USE & UNACCOUNTED-FOR-GAS

TOTAL HISTORICAL PLANNING LOAD (BBTU)

	ACTUAL		NORMAL	
Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2017-2018	569	261	569	246
2018-2019	597	254	573	262
2019-2020	545	257	591	245
2020-2021	551	244	633	262
2021-2022	567	248	631	266

TOTAL FORECAST PLANNING LOAD (BBTU)

	NORMAL		DESIGN [1]	
Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2023-2024	752	380	883	380
2024-2025	749	376	879	376
2025-2026	752	382	882	382
2026-2027	765	391	897	391
2027-2028	777	398	909	398

[1] Based on the aggregate ratio of design year to normal year

Table G-5
MASS EFSC

COMPANY PLANNING LOAD
TOTAL PLANNING LOAD
(Including Company Use and Unaccounted-for-Gas)

TOTAL HISTORICAL PLANNING LOAD (BBTU)

	ACTUAL		NORMAL	
Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2017-2018	32,133	14,724	32,188	14,369
2018-2019	33,755	14,330	32,923	14,603
2019-2020	30,789	14,528	32,932	14,106
2020-2021	30,981	13,747	34,460	14,280
2021-2022	31,917	13,928	34,611	14,494

TOTAL FORECAST PLANNING LOAD (BBTU)

	NORMAL		DESIGN	
Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2023-2024	34,677	12,205	39,526	12,205
2024-2025	34,428	11,964	39,273	11,964
2025-2026	34,600	12,312	39,437	12,312
2026-2027	35,297	12,814	40,201	12,814
2027-2028	35,881	13,169	40,844	13,169

TABLE G-14

Eversource Gas Company of Massachusetts
Exisiting On-System Peaking Resources

LNG Facility	Division	No. Tanks	Gallons Liquid per Tank	Capacity Total MMBtu (net of heel)	Vaporization MDWQ
Easton	Brockton	1	9,393,300	731,704	44,000
Lawrence	Lawrence	5	30,208	11,628	12,500
Ludlow	Springfield	1	12,173,947	948,413	48,000
Marshfield	Brockton	2	49,500	7,622	8,000
Total Brockton				739,326	52,000
Total SP/LAW				960,041	60,500
Total				1,699,367	112,500
Propane Facility					
Meadowlane	Brockton	12	72,297	70,749	21,000
Lawrence	Lawrence	3	53,505	13,033	14,000
N. Hampton	Springfield	5	53,505	21,722	5,000
Total Brockton				70,749	21,000
Total SP/LAW				34,755	19,000
Total				105,504	40,000

Table G-22N, Page 1
MASS EFSC

COMPARISON OF RESOURCES AND REQUIREMENTS

NORMAL YEAR (Bbtu)

HEATING SEASON - Base Case

	Season	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
	REQUIREMENTS					
1	FIRM	34,677	34,428	34,600	35,297	35,881
2	Sub Total	34,677	34,428	34,600	35,297	35,881
3	Injections					
4	LNG	42	0	0	0	0
5	LPG	0	0	0	0	0
6	Underground	0	0	0	0	0
7	Sub Total	42	0	0	0	0
8	**Total**	**34,720**	**34,428**	**34,600**	**35,297**	**35,881**
	RESOURCES					
9	Pipeline					
10	TGP	14,172	13,887	13,716	14,038	14,306
11	AGT/TETCO	11,986	11,849	12,105	12,422	12,777
12	LNG Injection	42	0	0	0	0
13	LPG Injection	0	0	0	0	0
14	Sum Total	26,200	25,736	25,820	26,461	27,083
15	Storage Withdrawals					
16	LNG	287	302	315	361	367
17	LPG	0	0	0	0	0
18	AGT/TETCO	2,947	2,938	2,970	2,970	2,952
19	TGP	5,285	5,452	5,494	5,506	5,478
20	Sub Total	8,519	8,691	8,780	8,837	8,798
21	Citygate Supplies	0	0	0	0	0
22	**Total**	**34,720**	**34,428**	**34,600**	**35,297**	**35,881**

Table G-22N, Page 2
MASS EFSC

COMPARISON OF RESOURCES AND REQUIREMENTS

NORMAL YEAR (Bbtu)

NON-HEATING SEASON - Base Case

	Season	Summer 2024	Summer 2025	Summer 2026	Summer 2027	Summer 2028
	REQUIREMENTS					
1	FIRM	12,205	11,964	12,312	12,814	13,169
2	Sub Total	12,205	11,964	12,312	12,814	13,169
3	Injections					
4	LNG	607	612	677	723	729
5	LPG	0	0	0	0	0
6	Underground	8,395	8,555	8,632	8,644	8,597
7	Sub Total	9,002	9,168	9,309	9,366	9,326
8	**Total**	**21,207**	**21,131**	**21,621**	**22,180**	**22,496**
	RESOURCES					
9	Pipeline					
10	TGP	10,922	11,163	11,401	11,510	11,582
11	AGT/TETCO	9,316	8,994	9,181	9,587	9,823
12	LNG Injection	607	612	677	723	729
13	LPG Injection	0	0	0	0	0
14	Sum Total	20,845	20,770	21,259	21,819	22,134
15	Storage Withdrawals					
16	LNG	362	362	362	362	362
17	LPG	0	0	0	0	0
18	AGT/TETCO	0	0	0	0	0
19	TGP	0	0	0	0	0
20	Sub Total	362	362	362	362	362
21	Citygate Supplies	0	0	0	0	0
22	**Total**	**21,207**	**21,131**	**21,621**	**22,180**	**22,496**

Table G-22D, Page 1
MASS EFSC

COMPARISON OF RESOURCES AND REQUIREMENTS

DESIGN YEAR (Bbtu)

HEATING SEASON - Base Case

	Season	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
	REQUIREMENTS					
1	FIRM	39,526	39,273	39,437	40,201	40,844
2	Sub Total	39,526	39,273	39,437	40,201	40,844
3	Injections					
4	LNG	51	11	12	15	15
5	LPG	21	21	21	21	21
6	Underground	0	0	0	0	0
7	Sub Total	72	32	33	36	36
8	**Total**	**39,598**	**39,305**	**39,470**	**40,237**	**40,880**
	RESOURCES					
9	Pipeline					
10	TGP	15,620	15,324	15,438	15,640	15,930
11	AGT/TETCO	14,944	14,792	14,725	15,193	15,517
12	LNG Injection	51	11	12	15	15
13	LPG Injection	21	21	21	21	21
14	Sum Total	30,637	30,148	30,196	30,869	31,483
15	Storage Withdrawals					
16	LNG	746	772	799	904	940
17	LPG	21	21	21	21	24
18	AGT/TETCO	2,947	2,938	2,970	2,970	2,956
19	TGP	5,237	5,415	5,473	5,456	5,456
20	Sub Total	8,951	9,146	9,262	9,351	9,376
21	Citygate Supplies	11	11	12	17	21
22	**Total**	**39,598**	**39,305**	**39,470**	**40,237**	**40,880**

Table G-22D, Page 2
MASS EFSC

COMPARISON OF RESOURCES AND REQUIREMENTS

DESIGN YEAR (Bbtu)

NON-HEATING SEASON - Base Case

	Season	Summer 2024	Summer 2025	Summer 2026	Summer 2027	Summer 2028
	REQUIREMENTS					
1	FIRM	12,205	11,964	12,312	12,814	13,169
2	Sub Total	12,205	11,964	12,312	12,814	13,169
3	Injections					
4	LNG	1,057	1,073	1,148	1,254	1,283
5	LPG	0	0	0	0	3
6	Underground	8,346	8,518	8,610	8,592	8,578
7	Sub Total	9,402	9,591	9,758	9,847	9,864
8	**Total**	**21,607**	**21,555**	**22,070**	**22,661**	**23,034**
	RESOURCES					
9	Pipeline					
10	TGP	10,873	11,033	11,229	11,405	11,559
11	AGT/TETCO	9,316	9,087	9,332	9,640	9,827
12	LNG Injection	1,057	1,073	1,148	1,254	1,283
13	LPG Injection	0	0	0	0	3
14	Sum Total	21,245	21,193	21,709	22,299	22,672
15	Storage Withdrawals					
16	LNG	362	362	362	362	362
17	LPG	0	0	0	0	0
18	AGT/TETCO	0	0	0	0	0
19	TGP	0	0	0	0	0
20	Sub Total	362	362	362	362	362
21	Citygate Supplies	0	0	0	0	0
22	**Total**	**21,607**	**21,555**	**22,070**	**22,661**	**23,034**

Tables G-22, Back-up
MASS EFSC

TABLE G-22 BACK-UP DATA - Base Case
Bbtu

A. Design Heating Season Ending Resources

		2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
	STORAGE INVENTORIES					
1	AGT STORAGE	118	127	94	94	108
2	TGP STORAGE	373	191	133	150	150
3	LNG	1,005	938	863	760	727
4	LPG	106	106	106	106	102
	PIPELINE GAS					
5	TGP	4,905	5,197	5,218	4,880	4,591
6	AGT / TETCO	6,197	6,349	6,556	5,948	5,624
	SUPPLEMENTAL					
7	LNG Optional Volumes					
8	Propane Optional Volumes					

B. THERMAL-VOLUMETRIC CONVERSION FACTORS

9 System Average
10 TGP
11 AGT
12 LNG

13 Propane gal/Btu
14 Propane Btu/cf

C. PERCENT LOSSES ASSOCIATED WITH STORAGE

	Storage Field	Loss Factor
15		
16		
17		

Tables G-23
MASS EFSC

COMPARISON OF RESOURCES AND REQUIREMENTS
PEAK DAY Bbtu

HEATING SEASON - Base Case

	REQUIREMENTS	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
1	Total Peak Day Sendout	521	520	523	531	538
	RESOURCES					
2	TGP-FT	136	136	136	136	136
3	AGT-FT	140	140	140	140	140
4	TGP STORAGE	69	69	69	69	69
5	AGT STORAGE	36	36	36	36	36
6	LNG from Storage	109	108	110	113	113
7	LPG from Storage	21	21	21	21	24
8	Citygate Supplies	11	11	12	17	21
0	TOTAL	521	520	523	531	538

TABLE G-24

Eversource Gas Company of Massachusetts
Long Term Contracts as of November 1, 2023

Pipeline	Contract	Rate Schedule	MDQ	ACQ	Days	Contract Expiration	Next Renewal Notice Date	EVERGREEN	ROFR Provision (Y/N)	Contracts for which EGMA is requesting approval in this Current Docket [/1]
Algonquin	93001EC	AFT-1E	51,632	15,467,350	365	10/31/2025	10/31/2024	Y	Y	N
Algonquin	93201AC	AFT-1	5,489	2,003,485	365	10/31/2025	10/31/2024	Y	Y	N
Algonquin	93401	AFT-1	5,690	2,076,850	365	10/31/2025	10/31/2024	Y	Y	N
Algonquin	93001F	AFT-1	18,490	6,748,850	365	10/31/2025	10/31/2024	Y	Y	N
Algonquin	94501	AFT-1	14,758	5,386,670	365	10/31/2025	10/31/2024	Y	Y	N
Algonquin	510352	AFT-1(X-35)	48,000	17,520,000	365	10/31/2025	10/31/2024	Y	Y	N
Algonquin	510066	AFT-1H	20,000	7,300,000	365	11/30/2025	11/30/2024	Y	Y	N
Algonquin/2	510804	AFT-1AIM	30,000	10,950,000	365	1/6/2032	1/6/2031	Y	Y	N
Granite	26-001-FT-1	FT-1	12,000	2,172,000	181	10/31/2024	None	N	N	N
Iroquois	182003	RTS-1	28,840	10,526,600	365	10/31/2027	10/31/2026	N	Y	N
National Fuel	N12604	FST	10,000	3,650,000	365	3/31/2025	3/31/2024	Y	Y	N
PNGTS	208540	FT	16,000	5,840,000	365	11/30/2032	11/30/2031	Y	N	N
PNGTS	208535	FT	45,500	16,607,500	365	10/31/2040	10/31/2039	Y	N	N
PNGTS	233301	FT(PXP)	14,300	5,219,500	365	10/31/2040	10/31/2039	Y	N	N
Texas Eastern	800462	CDS	36,369	13,274,685	365	10/31/2029	10/31/2024	Y	Y	N
Texas Eastern	800414	CDS	1,056	385,440	365	10/31/2029	10/31/2024	Y	Y	N
Texas Eastern	800382	FT-1	4,235	1,545,775	365	10/31/2029	10/31/2024	Y	Y	N
Tennessee	5173-FTATGP	FT-A	12,748	4,653,020	365	10/31/2028	10/31/2027	Y	Y	N
Tennessee	5293-FTATGP	FT-A	12,547	4,579,655	365	10/31/2029	10/31/2028	Y	Y	N
Tennessee	39741-FTATGP	FT-A	4,081	1,489,565	365	3/31/2025	3/31/2024	Y	Y	N
Tennessee	5291-FTATGP	FT-A	6,171	2,252,415	365	3/31/2025	3/31/2024	Y	Y	N
Tennessee	48427-FTATGP	FT-A	17,000	6,205,000	365	10/31/2025	10/31/2024	Y	Y	N
Tennessee	41098-FTATGP	FT-A	18,733	6,837,545	365	10/31/2027	10/31/2026	Y	Y	N
Tennessee	95349-FTATGP	FT-A	9,774	3,567,510	365	10/31/2027	10/31/2026	Y	Y	N
Tennessee	98775-FTAHTGP	FT-A	6,100	2,226,500	365	10/31/2032	10/31/2030	Y	Y	N
Tennessee	330904-FTATGP	FT-A	96,400	35,186,000	365	10/31/2038	10/31/2037	Y	Y	N
Tennessee	5196-FTATGP	FT-A	15,375	5,611,875	365	4/30/2045	4/30/2044	Y	Y	N
Tennessee	362252 -FTILTGP	FT-IL	14,000	5,110,000	365	10/31/2024	10/31/2023	N	N	N
Tennessee	645-ITTGP	IT	50,000	18,250,000	365	12/31/2049	None	N	N	N
TransCanada/3	64198	FT	59,827	21,836,855	365	10/31/2040	10/31/2039	Y	Y	N
TransCanada SH	63398	FT	26,063	9,512,995	365	10/31/2026	10/31/2025	Y	Y	Y
TransCanada MH	63397	FT	16,000	5,840,014	365	10/31/2026	10/31/2025	Y	Y	Y
Transco	9239453	FT	1,254	457,710	365	10/8/2024	10/8/2023	Y	Y	N
Union Gas	**M12204**	**M12**	**26,352**	**9,618,480**	**365**	**10/31/2026**	**10/31/2024**	**N**	**Y**	**Y**
Union Gas	M12292	M12	61,218	22,344,425	365	10/31/2040	10/31/2038	N	Y	N
Millennium	217524	FT-1	15,000	5,475,000	365	3/31/2034	3/31/2033	N	Y	N

Underground Storage			MDWQ	Capacity						
Eastern Gas/4	**600002**	**GSS-TE**	**14,758**	**1,441,753**	**151**	**3/31/2026**	**3/31/2024**	**N**	**Y**	**Y**
National Fuel	O12603	FSS	10,000	1,100,000	151	3/31/2025	3/31/2024	Y	Y	N
Texas Eastern	400502	FSS-1	1,056	63,360	151	4/30/2029	4/30/2024	Y	Y	N
Texas Eastern	400193	SS-1	22,819	1,588,950	151	4/30/2029	4/30/2024	Y	Y	N
Tennessee	5178	FS-MA	19,755	1,222,594	151	10/31/2028	10/31/2027	Y	Y	N
Enbridge/5	**LST166/LST143**	**USS**	**16,000**	**1,600,000**	**100**	**3/31/2026**	**3/31/2025**	**N**	**N**	**Y**
Enbridge/5	**LST165/LST144**	**USS**	**26,500**	**1,820,000**	**69**	**3/31/2026**	**3/31/2025**	**N**	**N**	**Y**

/1: EGMA has determined that the contracts for which the Company requests approval have (a) no material changes and (b) no reasonable alternatives.
/2: Revised Term date since contract was not fully operational in 11/01/2016 and instead full MDQ was available on Jan 6, 2017.
/3: This was mistakenly not included in D.P.U. 21-118 F&SP Table G-24 - this is transportation for Canadian Dawn supplies which the Department approved in D.P.U. 17-172.
/4: EGMA Received approval w DPU 21-118 to renew this contract, pending Company contract execution in Q1 2024.
/5: EGMA Received approval w DPU 21-118 to renew this contract, but notification falls within 2 year window, therefore asking for approval for another term.

Appendix 2

Eversource Gas Company of Massachusetts
Existing Capacity Paths

Path #	Segment #	Contract	Expiration	Supply Source					
A	1	TGP/FT-A - 5173	31-Oct-28	*Texas*	4,462 Zone 0				
				Louisiana	8,286 Zone 1				
					12,748	12,748 EGMA CITYGATE			
B	1	TENN Storage - 5178	31-Oct-28	NY / Penn	19,755	19,755 TGP ELLISBURG			
	2	TGP/FT-A - 5196	30-Apr-45				5,500 EGMA CITYGATE		
	3	TGP/FT-A - 5293	31-Oct-29				12,547 EGMA CITYGATE		
C	1	NAT FUEL Storage O12603	31-Mar-25	NY / Penn	10,000	10,000 Nat Fuel			
	2	NAT FUEL FST -N12604	31-Mar-25			10,000 TGP ELLISBURG			
	3	TGP/FT-A - 5196	30-Apr-45				9,875 EGMA CITYGATE		
D	1	TGP/FT-A - 5291	31-Mar-25	Niagara, NY	6,171	6,171 EGMA CITYGATE			
E	1	TGP/FT-A - 39741	31-Mar-25	Niagara, NY	4,081	4,081 EGMA CITYGATE			
F & G	1	ENB STORAGE - LST165/144	31-Mar-26		26,500				
	2	UNION - M12204	31-Oct-26	Dawn	26,352	26,352 Parkway			
	3	TRANSCANADA - 63398	31-Oct-26				26,063 TCPL		
			TCPL						
	5	SPOT		Waddington, NY					
	6	IGTS/RST-1 - 182003	01-Nov-27		28,840	28,840 IROQ WRIGHT			
	7	TGP/FT-A - 95349	31-Oct-27				6,068 EGMA CITYGATE		F
	8	TGP/FT-A - 95349	31-Oct-27				3,706 EGMA CITYGATE		F
	8	TGP/FT-A - 41098	31-Oct-27			18,733 AGT MENDON			
	9	AGT/FT-2 - 93001F	31-Oct-25				18,490 EGMA CITYGATE		G
I & S	1	TETCO/CDS - 800462	31-Oct-29	*Texas*	16,408				
				Louisiana	37,687				
					36,369	36,369 AGT LAMBERTVILLE			
			TETCO						
	2	SPOT (**S**)		*Lambertville/Hanover*	36,369				
	2	AGT/AFT-E/1 - 93201AC	31-Oct-25			5,489			
	3	AGT/AFT-E/1 - 93401	31-Oct-25			5,690			
	4	AGT/AFT-E/1 - 93001EC	31-Oct-25			27,757			
						38,936 EGMA CITYGATE			
J	1	TETCO Storage - 400193	30-Apr-29	NY / Penn / WV	22,819	22,819 AGT LAMBERTVILLE			
	2	AGT/AFT-E/1 - 93001EC	31-Oct-25				22,819 EGMA CITYGATE		
K	1	TETCO Storage - 400502	30-Apr-29	NY / Penn / WV	1,056	1,056 STOR W/D POINT			
	2	TETCO CDS - 800414	31-Oct-29				1,056 AGT LAMBERTVILLE		
	3	AGT/AFT-E/1 - 93001EC	31-Oct-25					1,056 EGMA CITYGATE	
L	1	EGTS Storage - 600002	31-Mar-26	NY / Penn / WV	14,758	14,758 STOR W/D POINT			
	2	TETCO- FT - 800382	31-Oct-29				4,235 AGT LAMBERTVILLE		
	2	TRANSCO/FT - 9239453	08-Oct-24				1,254 AGT LAMBERTVILLE		
	3	*SECONDARY*					9,269 AMA SECONDARY		
	4	AGT/AFT-1 - 93201AC	31-Oct-25					14,758	
M	1	ENB STORAGE - LST166/143	31-Mar-26	Dawn	16,000				
	2	TRANSCANADA - 63397	31-Oct-26			16,000 PNGTS Pittsburgh, NH			
	3	PNGTS/WS - 208540	30-Nov-32			16,000 TGP Dracut			
	4	TGP FT - 330904	31-Oct-38			16,000 EGMA CITYGATE			
N	1	UNION - M12292		Dawn	61,218				
	2	TRANSCANADA - 64198		Pittsburgh, NH	59,827	TGP Dracut/Haverill			
	3	PNGTS/FT - 208535	31-Oct-40			45,500			
	4	PNGTS/FT - 233301	31-Oct-40			14,300			
H	5	Repsol Peaking	31-Mar-28	Canaport		47,000			
Q	6	GNST/FT - 26-001-FT-1	31-Oct-24				12,000 NUI Exchange		12,000 EGMA CITYGATE
	7	TGP FT - 98775	31-Oct-32				6,100 EGMA CITYGATE		
	7	TGP FT - 48427/362252	31-Oct-25				17,000 EGMA CITYGATE		
	7	TGP FT - 330904	31-Oct-38				80,400 EGMA CITYGATE		
								103,500	
P	1	AGT AFT-1(H) - 510066	30-Nov-25	Beverly, MA	20,000	20,000 EGMA CITYGATE			
R	1	AGT AFT-1 (X-35) - 510352	31-Oct-25	Transco	48,000	48,000 EGMA CITYGATE			
T	1	MLP (FT-1) - 217524	31-Mar-34	Corning, NY	15,000	Ramapo, NJ	20,000 AGT Sharon Station, MA		
	2	AGT (AFT-1 AIM) - 510804	06-Jan-32			30,000	10,000 AGT Taunton/South Attleboro		
								30,000 EGMA CITYGATE	

Appendix 3: Statistical Techniques and Glossary

Regression modeling techniques were used to generate the demand forecasts for the four divisions. The regression analyses were developed using the EViews software package. Regression modeling techniques were used to develop separate Brockton, Lawrence, and Springfield forecasts of number of customers and use per customer for Residential Heating, Residential Non-Heating, LLF, and HLF customer segments, for sales and transportation combined, and for sales.[1]

Regression Analysis

Econometrics is the empirical determination of economic laws; it involves the application of statistical techniques and analyses to the study of economic data. A fundamental statistical method of econometrics is regression analysis, which is concerned with the study of the relationship between one variable, i.e., the dependent variable, and one or more other variables, i.e., the independent or explanatory variables. One of the primary uses of regression analysis is to forecast the values of the dependent variable, given forecast values of the independent variables.[2]

Regression equations that included appropriate variables (e.g., weather, natural gas price, economic data, etc.) were identified and tested to develop the forecast models. Each of the forecast models explains historical values of the dependent variable as a function of historical values of the independent variables; the models produce forecasted values of the dependent variable based on forecasted values of the independent variables.

"Sound econometric modeling and analysis generally follows a common process: (a) create statement of theory; (b) collect data; (c) specify mathematical model; (d) specify statistical model; (e)

1 A total of 36 models were developed to forecast customer demand
2 A glossary of statistical terms can be found at the end of this Appendix.

estimate model parameters; (f) check model accuracy; (g) test hypotheses; and (h) use model for forecasting." (Essentials of Econometrics, Damodar Gujarati, p. 3 (1999 Irwin McGraw-Hill)).

The forecast models that were developed for the 2023 F&SP followed this process. First, economic theory and standard utility forecasting practice was used to identify (a) variables that could have an effect on the dependent variable in each equation, and (b) the expected sign of the coefficients for those variables. For example, the EDD variable is expected to affect use per customer, and the EDD coefficient should be positive (i.e., when EDDs increase, demand should increase, and vice versa). The price variable is also expected to affect use per customer and the price coefficient should be negative (i.e., when natural gas prices increase, demand should decrease, and vice versa).

For each of the models, after possible explanatory variables were identified and the data sets were developed, regression equations were estimated to test various combinations of independent variables. A preliminary regression equation was identified for each model based on (1) the theoretical relevance and signs of the independent variables; (2) the results of various statistical tests that assess the significance of the independent variables included in the equation; and (3) the explanatory power of the equation as a whole. If the sign of an independent variable was counter to expectations or if important variables were not significant, either, (a) that model was not considered further or (b) modified forms of the model with different variables were considered. The statistical significance of each independent variable was determined by examining the variable t-test values. Variables that were significant at the 0.10 level were included in a model.[3] Finally, equations were evaluated based on explanatory power, as determined by the R^2. Models that met all of these criteria were subjected to further testing for autocorrelation, heteroskedasticity, stability, multicollinearity, and outliers; the

[3] Depending on specific circumstances, acceptable statistical practice allows for including variables that are not statistically significant in a regression model.

performance of each model was also assessed using an ex post analysis. Lastly, models were evaluated based on the reasonableness of the forecast values by comparing forecast trends and growth rates to historical trends and growth rates for relevant historical periods, while also accounting for the effect of independent variables during these historical and forecast periods.

Autocorrelation

Statistical theory requires that the residuals associated with a regression equation (the "errors") be independent of one another (i.e., there should be no relationship or correlation in the residuals over time) to ensure that the equation is efficient.[4] Correlation of residuals over time is known as "autocorrelation". If the error terms are autocorrelated, the efficiency of ordinary least-squares (OLS) parameter estimates is adversely affected. One aspect of time series analysis is to identify and correct for autocorrelation.

Autocorrelation can be present between two consecutive periods (lag 1 or first-order), periods separated by one period (lag 2 or second-order), periods separated by two periods (lag 3 or third-order), etc. The autocorrelation function ("ACF") and partial autocorrelation function ("PACF") values and graphs can be used to test for higher orders of autocorrelation.[5] Advanced statistical packages correct for higher order autocorrelation, based on user inputs.

The forecast models for this F&SP were examined for autocorrelation from lag(s) 1 through 8 using the ACF and PACF values and graphs. If autocorrelation was identified, the appropriate autoregressive terms ("AR") were added to the regression equation to correct for the autocorrelation (e.g., autocorrelation at lag 4 could be corrected by adding an AR4 term to the regression equation). The regression equations were re-evaluated after any necessary corrections for autocorrelation were

[4] In statistical theory, coefficient estimates are "efficient" if, comparing all unbiased estimates, they have the smallest (i.e., minimum) variance.
[5] The presence of autocorrelation is indicated by ACF or PACF values that fall beyond two standard errors.

made. If correcting for autocorrelation in residuals decreased an independent variable's t-statistic to the extent that the variable was no longer significant, the equation parameters were re-estimated with the statistically insignificant variables excluded. The ACF and PACF values and graphs for each model are presented in the detailed statistical results appendix.

Heteroskedasticity

Statistical theory also requires that the residuals associated with a regression equation have constant variance to ensure that the equation is efficient. Non-constant variance is known as "heteroskedasticity". The forecast models for this F&SP were tested for heteroskedasticity using White's Test. The White's Test statistic is developed by regressing the squared residuals from the original regression against the original independent variables, the independent variables squared, and the cross products. The R^2 from this new regression is multiplied by the number of observations compared against a distribution to test for significance; models with White's Test results that were not significant at the 0.01 level were considered to not exhibit heteroskedasticity. Results of the White's test for each model are presented in the detailed statistical results appendix.

Stability and Structural Change

The Chow test was used to test for break points or structural changes in each model. The Chow test involves splitting the historical data into two parts and comparing the sum of squared errors from the original model to the sum of squared errors of the two subset models that are based on re-estimating the original model prior to and post the potential structural break. If the two subset models have significantly lower sum of squared errors than the original model, then the original model is considered to have failed the stability test. Models with Chow test results that were not significant at the 0.01 level were considered to be stable.

The Chow test was performed for each regression equation for any break point suspected of being associated with a structural change. If any structural change was determined to be statistically significant on the basis of the Chow test, shifts in either the intercept or a particular slope coefficient associated with the structural change were incorporated into the model with dummy variables and/or interaction terms. Results of the Chow test for each model are presented in the detailed statistical results appendix.

Multicollinearity

A key assumption of multiple regression analysis is that there is no exact linear relationship among the independent variables. In the case of an exact linear relationship (or perfect multicollinearity) estimation of the parameters of the model is not possible. In practice, there is always some degree of less-than-exact multicollinearity among the independent variables of a multiple regression model.

To test for multicollinearity, a correlation matrix of driving variables for each model developed was calculated and evaluated.[6] The correlation matrices did not include (a) dummy variables that apply to one year or less of the historical data (i.e., point dummy variables or very short duration dummy variables) because they are not driving variables and (b) interactive terms (or product terms) if one or more of its component parts were also in the model, because according to Jaccard and Turrisi (2003):

> "… high levels of collinearity between a product term and its component parts generally will not be problematic for interaction analysis unless the collinearity is so high that it disrupts the computer algorithm designed to isolate the relevant standard errors in a standard computer statistical package." (Jaccard, James and Turrisi, Robert, Interaction Effects in Multiple Regression. Sage Publications, 2003, p. 27-28)

The correlation matrices for each model are provided in the detailed statistical appendix.

If a particular equation demonstrated high correlation values among driving variables (i.e., greater than 0.9, or less than -0.9), a Klein test would be performed to further evaluate the presence of multicollinearity. In those instances where the Klein test failed, the equations were re-specified to address the multicollinearity.

[6] "The model shows no multicollinearity in driving variables…" D.P.U. Order 10-100, Berkshire Gas Company, p. 11.

Outliers

Residual values are provided for each customer segment model in the detailed statistical appendix, which contains tables of quarterly values of actuals, fitted values, residuals, percent residuals, and standardized residuals. The values of the standardized residuals express the residuals in terms of their deviations from average values (i.e. standard errors). Models that had standardized residuals over 3.0, which indicates an outlier that is approximately outside the 99.7% confidence interval, were re-specified.

Ex Post Forecast

For this F&SP, ex post forecasts were performed by suppressing the last four quarters of historical data (i.e., 2021Q4 – 2022Q3) and re-estimating the model. The forecast for the suppressed quarters was compared with the actual data for these quarters and the parameter estimates from the "new" models with the suppressed quarters were compared to the parameter estimates from the original models. The results of the ex post forecasts for each model are included in the detailed statistical appendix.

Summary

If the overall explanatory power of the model was drastically reduced after correcting for the statistical issues described above, another preliminary model was examined. This process continued until a model was developed with appropriate statistical properties and explanatory power. Details associated with final model results, including all parameters, residuals, and the results of all the statistical tests described above can be found in the detailed statistical appendix.

Glossary of Statistical Terms[7]

Term	Definition
Adjusted R^2	A measure of the overall goodness of fit for the regression model, taking into account the number of independent variables in the model. Adjusted R^2 ranges from 0 to 1; the closer the Adjusted R^2 value is to 1, the better the fit of the model. Adjusted R^2 can be interpreted as the amount of variability of the dependent variable that is explained by the regression equation, taking into consideration the number of independent variables in the model.
Autocorrelation	A measure of the correlation of the values of a series with the values lagged by 1 or more orders. (Other equivalent terms include: serial correlation)
Autocorrelation Function ("ACF")	A function defined as the autocorrelation of the residuals at various lags; can be shown as a graph.
Correlation	A measure of the degree of relationship between two variables. The value of a correlation can range from -1 to 1, with values close to +/-1 indicating a strong relationship between two variables and a correlation close to 0 indicating no relationship between the variables.
Dependent Variable	A dependent variable is one that is observed to change in response to the independent variables. (Other equivalent terms include: response variable, result variable, outcome variable, endogenous variable, output variable, Y-variable)
Estimate (of the Independent Variable)	A measure of the value of the model parameter (i.e., independent variable). (Other equivalent terms include: coefficient of the independent variable)
F statistic	A measure of whether a regression equation is significant (i.e., whether the set of independent variables in a model explains a significant portion of the variability of the dependent variable). Calculated as the mean-square regression divided by the mean square residuals. The value of the F statistic ranges from zero to positive infinity, with large positive values indicating that the model is significant. (Equivalent terms include: t-Statistic, t-Test, Student's t)
Forecast	The dependent variable values predicted by the model for the forecast period.
Independent Variable	A variable used to explain the behavior of another variable (see Dependent Variable) in a regression equation. (Other equivalent terms include: explanatory variable, exogenous variable, external variable, predictor variable, causal variable, input variable, X-variable, regressors)
Model	A specific set of independent variables and their parameters used to explain a dependent variable. (Other equivalent terms include: Equation)
Number of Observations ("N")	The amount of data used to develop the model (i.e., the number of data points that are included for each variable in the model).

7 These terms are defined as they relate to the econometric/regression analysis used in this F&SP.

Term	**Definition**
Number of Predictors	The amount of independent variables included in the model. Note that Number of Predictors measures the total number of independent variables included in the model, not only the significant independent variables.
Partial Autocorrelation Function ("PACF")	A function defined as the partial autocorrelation of the residuals at various lags. Partial autocorrelation is a measure of the correlation of the values of a series with values lagged by one or more orders, after the effects of correlations at the intervening lags have been removed; can be shown as a graph.
R^2	A measure of the overall goodness of fit for the regression model. R^2 ranges from 0 to 1; the closer the R^2 value is to 1, the better the fit of the model. R^2 can be interpreted as the amount of variability of the dependent variable that is explained by the regression equation.
Residual	The difference between the actual historical values of the dependent variable and the values predicted by the model (i.e., the model fits). (Other equivalent terms include: error, error term)
Standard Error of the Regression ("S.E. of Regression)	A measure of the variability of the residuals. (Other equivalent terms include: Root Mean Square Error or RMSE)
Significance of the t statistic	A measure of the strength (or significance level) of the t statistic. A low value of the significance level of the t statistic is desired, as it indicates the related independent variable is significant in the equation. In general, only independent variables that had t statistics that were significant at the 0.10 level (i.e. less than 0.10) were included in the final equation. (Other equivalent terms include: p-value) Although statistical significance is dependent on the number of observations and number of explanatory variables in the equation, generally, t statistics greater than 2.0 are statistically significant.
Standard Error (of the Estimate of the Independent Variable) ("SE")	A measure of how much the value of a test statistic varies (i.e., the standard deviation of the sampling distribution for a statistic), in this case the Estimate of the Independent Variable.
t statistic	A measure of whether the coefficient for an independent variable is statistically different than zero. Calculated as the Estimate of the Independent Variable divided by its Standard Error. The value of t ranges from negative infinity to positive infinity, with values far from zero indicating that the independent variable is significant in the model. (Other equivalent terms include: t-Statistic, t-Test, Student's t)

RHC Brockton S&T

I. Sales and Transportation - Customers

A. Residential Heating Customers - Sales and Transportation

1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
B_RH_CUST_S_T	7	0.980	36.344

ARIMA Model Parameters

B_RH_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	70101.51	2143.557	32.70	0.000
	B_PINC(-4)	0.199556	0.006	31.56	0.000
	B_D15Q1	2368.064	1368.322	1.73	0.091
	B_D12Q2	-4598.768	1380.313	-3.33	0.002
	B_D12Q3	-4031.667	1383.336	-2.91	0.006
	B_D2011	-4722.084	794.859	-5.94	0.000
	B_D2013	-2335.006	758.802	-3.08	0.004

Variable	Definition	Explanation	Dummy Variable Support
B_PINC(-4)	Total personal income in Brockton (million $2012) lagged four quarters		
B_D15Q1	Binary variable equal to 1 in 2015Q1		2
B_D12Q2	Binary variable equal to 1 in 2012Q2		2
B_D12Q3	Binary variable equal to 1 in 2012Q3		2
B_D2011	Binary variable equal to 1 in 2011		2
B_D2013	Binary variable equal to 1 in 2013		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)

B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed

C: To account for seasonality

1: Included to address a structural shift

2: Included to address an outlier

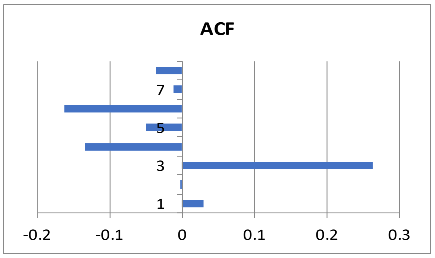
N	Adjusted R2	F Statistic
47	0.977154	328.9122

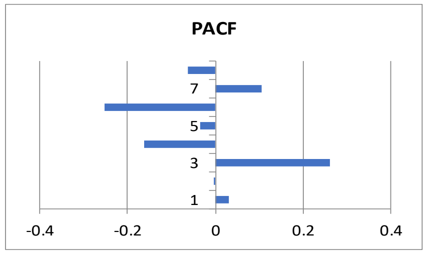
Chow Test Stats	N	k	SSR
Combined	47	7	69,788,417.77
1	26	7	31,147,065.06
2	21	2	29,231,503.90

Chow Stat:	0.735
P-Value:	0.644155

Heteroscedasticity - White's Test	
White Stat	0.43
Significance (p-value)	0.85

Correlations	B_PINC(-4)	B_D15Q1	B_D12Q2	B_D12Q3	B_D2011	B_D2013
B_PINC(-4)	1	-0.124148	-0.156951	-0.164465	-0.38659	-0.28293
B_D15Q1	-0.124148	1	-0.021739	-0.021739	-0.04497	-0.044969
B_D12Q2	-0.156951	-0.021739	1	-0.021739	-0.04497	-0.044969
B_D12Q3	-0.164465	-0.021739	-0.021739	1	-0.04497	-0.044969
B_D2011	-0.386589	-0.044969	-0.044969	-0.044969	1	-0.093023
B_D2013	-0.28293	-0.044969	-0.044969	-0.044969	-0.09302	1





Residual ACF										
Model			1	2	3	4	5	6	7	8
b_rh_cust_s_t Model	ACF		0.03	-0.001	0.263	-0.134	-0.049	-0.162	-0.011	-0.036
	SE		0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292
Residual PACF										
Model			1	2	3	4	5	6	7	8
b_rh_cust_s_t Model			0.03	-0.002	0.263	-0.161	-0.034	-0.253	0.107	-0.061
	SE		0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2011Q1	120935	119274	1661.77	1.37%	1.26
2011Q2	120273	120423	-149.522	-0.12%	(0.11)
2011Q3	119718	121267	-1549.02	-1.29%	(1.17)
2011Q4	121357	121320	36.7722	0.03%	0.03
2012Q1	122664	126094	-3429.36	-2.80%	(2.60)
2012Q2	122235	122235	-1.2E-11	0.00%	(0.00)
2012Q3	122415	122415	-1.1E-11	0.00%	(0.00)
2012Q4	124242	126478	-2236.05	-1.80%	(1.69)
2013Q1	125486	124793	692.704	0.55%	0.52
2013Q2	125016	125351	-335.744	-0.27%	(0.25)
2013Q3	124761	124954	-192.175	-0.15%	(0.15)
2013Q4	126887	127051	-164.785	-0.13%	(0.12)
2014Q1	128335	127093	1241.78	0.97%	0.94
2014Q2	127655	127619	35.9758	0.03%	0.03
2014Q3	127163	127763	-599.933	-0.47%	(0.45)
2014Q4	129468	127985	1483.2	1.15%	1.12
2015Q1	130890	130890	-1E-11	0.00%	(0.00)
2015Q2	130471	129033	1437.33	1.10%	1.09
2015Q3	129940	130150	-210.456	-0.16%	(0.16)
2015Q4	132096	131615	480.917	0.36%	0.36
2016Q1	133289	132874	415.042	0.31%	0.31
2016Q2	132701	133681	-979.17	-0.74%	(0.74)
2016Q3	132573	133898	-1325.46	-1.00%	(1.00)
2016Q4	134335	134951	-616.026	-0.46%	(0.47)
2017Q1	135337	135070	267.237	0.20%	0.20
2017Q2	135123	135388	-264.539	-0.20%	(0.20)
2017Q3	135051	136351	-1300.1	-0.96%	(0.98)
2017Q4	137088	136243	845.071	0.62%	0.64
2018Q1	138280	136737	1543.51	1.12%	1.17
2018Q2	138065	137572	492.412	0.36%	0.37
2018Q3	137697	138293	-596.001	-0.43%	(0.45)
2018Q4	139445	138547	897.44	0.64%	0.68
2019Q1	140296	139356	940.382	0.67%	0.71
2019Q2	140182	139510	672.147	0.48%	0.51
2019Q3	140043	140108	-64.7817	-0.05%	(0.05)
2019Q4	141622	140693	928.555	0.66%	0.70
2020Q1	142735	142722	13.6295	0.01%	0.01
2020Q2	143481	142525	956.022	0.67%	0.72
2020Q3	143947	142542	1404.93	0.98%	1.06
2020Q4	144685	143181	1503.62	1.04%	1.14
2021Q1	145550	144164	1386.05	0.95%	1.05
2021Q2	145786	148609	-2822.3	-1.94%	(2.14)
2021Q3	146108	146389	-281.636	-0.19%	(0.21)
2021Q4	146842	146995	-153.27	-0.10%	(0.12)
2022Q1	147473	151013	-3540.64	-2.40%	(2.68)
2022Q2	148320	147882	437.585	0.30%	0.33
2022Q3	148345	147308	1036.9	0.70%	0.79

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	146842	147412	-570.00	-0.4%
Q1 2022	147472.7	151557.4	-4084.70	-2.8%
Q2 2022	148319.7	148326.9	-7.20	0.0%
Q3 2022	148344.7	147734.4	610.30	0.4%
Total	590979.10	595030.70	-4051.60	-0.7%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	70101.51	68080.59	2020.92	3%
B_PINC(-4)	0.199556	0.205882	-0.006326	-3%
B_D15Q1	2368.064	2536.984	-168.92	-7%
B_D12Q2	-4598.768	-4376.321	-222.447	5%
B_D12Q3	-4031.667	-3796.959	-234.708	6%
B_D2011	-4722.084	-4450.791	-271.293	6%
B_D2013	-2335.006	-2145.483	-189.523	8%

RHC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
L_RH_CUST_S_T	11	0.998	9.577

ARIMA Model Parameters

L_RH_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	19365.16	1891.568	10.24	0.000
	L_CUMULATIVE_HC(-3)	0.067347	0.005	13.92	0.000
	L_D18Q4	-2811.218	76.327	-36.83	0.000
	L_D18Q3	-2584.902	102.707	-25.17	0.000
	L_D22Q3	-528.4603	98.901	-5.34	0.000
	L_AFT_D21Q3	-151.1755	60.568	-2.50	0.021
	L_D15Q3	-247.8396	81.841	-3.03	0.006
	L_D15Q2	-178.3481	78.304	-2.28	0.033
	L_D19Q3	-273.8248	90.260	-3.03	0.006
	L_D17Q3	-266.3664	91.190	-2.92	0.008
	AR(4)	0.669837	0.080	8.38	0.000

Variable	Definition	Explanation	Dummy Variable Support
L_CUMULATIVE_HC(-3)	Cumulative housing completions (# of units) in Lawrence lagged three quarters		
L_D18Q4	Binary variable equal to 1 in 2018Q4		2
L_D18Q3	Binary variable equal to 1 in 2018Q3		2
L_D22Q3	Binary variable equal to 1 in 2022Q3		2
L_AFT_D21Q3	Binary variable equal to 1 from 2021Q3 on		1
L_D15Q3	Binary variable equal to 1 in 2015Q3		2
L_D15Q2	Binary variable equal to 1 in 2015Q2		2
L_D19Q3	Binary variable equal to 1 in 2019Q3		2
L_D17Q3	Binary variable equal to 1 in 2017Q3		2
AR(4)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

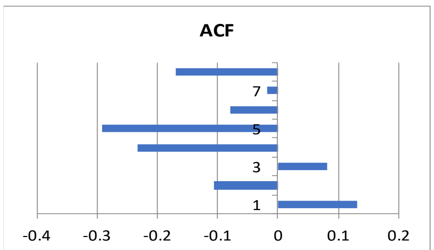
N	Adjusted R2	F Statistic
32	0.996511	886.4661

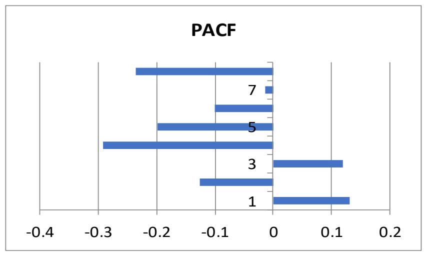
Chow Test Stats	N	k	SSR
Combined	34	11	246,588.90
1	17	6	92,511.87
2	17	8	92,325.18

Chow Stat:	0.364
P-Value:	0.947432

Heteroscedasticity - White's Test	
White Stat	0.87
Significance (p-value)	0.57

Correlations									
	L_CUMULATIVE_HC(-3)	L_D18Q4	L_D18Q3	L_D22Q3	L_AFT_D21Q3	L_D15Q3	L_D15Q2	L_D19Q3	L_D17Q3
L_CUMULATIVE_HC(-3)	1	0.010255	-0.01413	0.304158	0.637256	-0.232098	-0.24683	0.068284	-0.10283
L_D18Q4	0.010255	1	-0.032258	-0.032258	-0.07729	-0.032258	-0.03226	-0.03226	-0.03226
L_D18Q3	-0.01413	-0.032258	1	-0.032258	-0.07729	-0.032258	-0.03226	-0.03226	-0.03226
L_D22Q3	0.304158	-0.032258	-0.032258	1	0.417365	-0.032258	-0.03226	-0.03226	-0.03226
L_AFT_D21Q3	0.637256	-0.07729	-0.07729	0.417365	1	-0.07729	-0.07729	-0.07729	-0.07729
L_D15Q3	-0.232098	-0.032258	-0.032258	-0.032258	-0.07729	1	-0.03226	-0.03226	-0.03226
L_D15Q2	-0.246829	-0.032258	-0.032258	-0.032258	-0.07729	-0.032258	1	-0.03226	-0.03226
L_D19Q3	0.068284	-0.032258	-0.032258	-0.032258	-0.07729	-0.032258	-0.03226	1	-0.03226
L_D17Q3	-0.102826	-0.032258	-0.032258	-0.032258	-0.07729	-0.032258	-0.03226	-0.03226	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_rh_cust_s_t Model	ACF	0.132	-0.106	0.082	-0.233	-0.291	-0.078	-0.019	-0.169
	SE	0.354	0.354	0.354	0.354	0.354	0.354	0.354	0.354
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_rh_cust_s_t Model		0.132	-0.125	0.119	-0.291	-0.199	-0.1	-0.014	-0.235
	SE	0.354	0.354	0.354	0.354	0.354	0.354	0.354	0.354

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2014Q4	41314	41406.7	-92.686	-0.22%	(1.01)
2015Q1	41854.3	41838.9	15.4412	0.04%	0.17
2015Q2	41430	41416.5	13.4585	0.03%	0.15
2015Q3	41158.7	41157.3	1.39735	0.00%	0.02
2015Q4	41935.7	41969.4	-33.7415	-0.08%	(0.37)
2016Q1	42410.3	42359.4	50.9655	0.12%	0.56
2016Q2	42239.3	42219.2	20.0923	0.05%	0.22
2016Q3	42128.3	42126.2	2.08611	0.00%	0.02
2016Q4	42668	42542.4	125.57	0.29%	1.37
2017Q1	43003.7	42910.8	92.8903	0.22%	1.01
2017Q2	42761.3	42856.2	-94.8237	-0.22%	(1.03)
2017Q3	42562	42562.6	-0.58001	0.00%	(0.01)
2017Q4	43201.7	43239.3	-37.6509	-0.09%	(0.41)
2018Q1	43540.3	43539	1.34292	0.00%	0.01
2018Q2	43381	43444.7	-63.681	-0.15%	(0.69)
2018Q3	40993.7	40994.5	-0.8659	0.00%	(0.01)
2018Q4	41081.3	41099.7	-18.4158	-0.04%	(0.20)
2019Q1	44015	44167.3	-152.338	-0.35%	(1.66)
2019Q2	44061.7	44091.6	-29.9712	-0.07%	(0.33)
2019Q3	43964.3	43965.6	-1.29271	0.00%	(0.01)
2019Q4	44443.3	44470.8	-27.493	-0.06%	(0.30)
2020Q1	44764	44606.9	157.095	0.35%	1.71
2020Q2	44901.3	44696.1	205.209	0.46%	2.24
2020Q3	44871.7	44873.6	-1.92989	0.00%	(0.02)
2020Q4	44968.7	45054.9	-86.259	-0.19%	(0.94)
2021Q1	45328	45279.6	48.3769	0.11%	0.53
2021Q2	45313.3	45405.5	-92.1968	-0.20%	(1.01)
2021Q3	45273.3	45272.4	0.90522	0.00%	0.01
2021Q4	45373.3	45404	-30.6669	-0.07%	(0.33)
2022Q1	45629	45694.6	-65.5929	-0.14%	(0.72)
2022Q2	45823.3	45728	95.3545	0.21%	1.04
2022Q3	45311.3	45311.3	1.8E-10	0.00%	0.00

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	45373.33	45404.09	-30.76	-0.1%
Q1 2022	45629	45696.51	-67.51	-0.1%
Q2 2022	45823.33	45728.28	95.05	0.2%
Q3 2022	45311.33	45837.36	-526.03	-1.2%
Total	182136.99	182666.24	-529.25	-0.3%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	19365.16	19572.16	-207	-1%
L_CUMULATIVE_HC(-3)	0.067347	0.066825	0.000522	1%
L_D18Q4	-2811.218	-2811.218	0	0%
L_D18Q3	-2584.902	-2584.144	-0.758	0%
L_D22Q3	-528.4603	0	-528.4603	100%
L_AFT_D21Q3	-151.1755	-147.8798	-3.2957	2%
L_D15Q3	-247.8396	-245.028	-2.8116	1%
L_D15Q2	-178.3481	-176.9971	-1.351	1%
L_D19Q3	-273.8248	-273.4448	-0.38	0%
L_D17Q3	-266.3664	-265.8851	-0.4813	0%
AR(4)	0.669837	0.678552	-0.008715	-1%

RHC Springfield S&T
3. Springfield

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
S_RH_CUST_S_T	8	0.997	12.509

ARIMA Model Parameters

S_RH_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	56652.51	3991.578	14.19	0.000
	S_CUMULATIV_HC(-3)	0.280418	0.032	8.79	0.000
	S_Q2_D2016_D2019	-365.999	124.047	-2.95	0.007
	S_D22Q3	-2751.477	176.817	-15.56	0.000
	S_Q3_D2015_D2019	-801.4067	122.289	-6.55	0.000
	S_D15Q4	-243.849	130.547	-1.87	0.073
	S_D22Q2	333.37	173.143	1.93	0.065
	AR(4)	0.674285	0.042	16.08	0.000

Variable	Definition	Explanation	Dummy Variable Support
S_CUMULATIV_HC(-3)	Cumulative housing completions (# of units) in Springfield lagged three quarters		
S_Q2_D2016_D2019	Binary variable equal to 1 in Q2 from 2016 to 2019	C	2
S_D22Q3	Binary variable equal to 1 in 2022Q3		2
S_Q3_D2015_D2019	Binary variable equal to 1 in Q3 from 2015 to 2019	C	2
S_D15Q4	Binary variable equal to 1 in 2015Q4		2
S_D22Q2	Binary variable equal to 1 in 2022Q2		2
AR(4)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
34	0.995654	1081.008

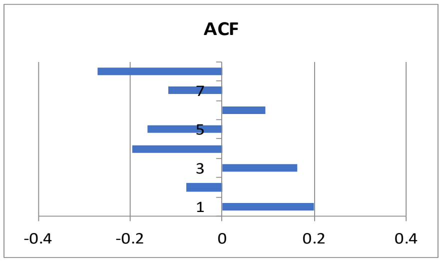
Chow Test Stats	N	k	SSR
Combined	34	8	636,563.63
1	17	6	241,081.48
2	17	7	189,860.69

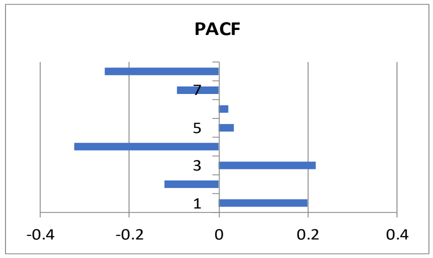
Chow Stat:	1.074
P-Value:	0.423028

Heteroscedasticity - White's Test	
White Stat	0.80
Significance (p-value)	0.60

Correlations

	S_CUMULATIV_HC(-3)	S_Q2_D2016_D2019	S_D22Q3	S_Q3_D2015_D2019	S_D15Q4	S_D22Q2
S_CUMULATIV_HC(-3)	1	-0.113948	0.309984	-0.165363	-0.18474	0.291011
S_Q2_D2016_D2019	-0.113948	1	-0.063564	-0.15162	-0.06356	-0.063564
S_D22Q3	0.309984	-0.063564	1	-0.072282	-0.0303	-0.030303
S_Q3_D2015_D2019	-0.165363	-0.15162	-0.072282	1	-0.07228	-0.072282
S_D15Q4	-0.184739	-0.063564	-0.030303	-0.072282	1	-0.030303
S_D22Q2	0.291011	-0.063564	-0.030303	-0.072282	-0.0303	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_rh_cust_s_t Model	ACF	0.199	-0.079	0.164	-0.195	-0.161	0.094	-0.116	-0.27
	SE	0.343	0.343	0.343	0.343	0.343	0.343	0.343	0.343
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_rh_cust_s_t Model		0.199	-0.123	0.218	-0.325	0.034	0.022	-0.092	-0.256
	SE	0.343	0.343	0.343	0.343	0.343	0.343	0.343	0.343

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2014Q2	83738.3	83729.4	8.89966	0.01%	0.06
2014Q3	83399.3	83597.8	-198.423	-0.24%	(1.27)
2014Q4	84745	84571.2	173.765	0.21%	1.11
2015Q1	85711	85520.9	190.108	0.22%	1.21
2015Q2	85104	85270.7	-166.687	-0.20%	(1.07)
2015Q3	84478.3	84269.8	208.555	0.25%	1.33
2015Q4	85681.3	85752	-70.635	-0.08%	(0.45)
2016Q1	86546.3	86680.4	-134.054	-0.15%	(0.86)
2016Q2	86051	85936.4	114.604	0.13%	0.73
2016Q3	85739.7	85664.3	75.333	0.09%	0.48
2016Q4	86866.7	86971.4	-104.756	-0.12%	(0.67)
2017Q1	87516	87451.6	64.4348	0.07%	0.41
2017Q2	87023.3	87075	-51.6247	-0.06%	(0.33)
2017Q3	86537	86774.1	-237.061	-0.27%	(1.52)
2017Q4	87660	87850.8	-190.755	-0.22%	(1.22)
2018Q1	88439	88361	78.0391	0.09%	0.50
2018Q2	87882.7	87965.4	-82.7167	-0.09%	(0.53)
2018Q3	87435.7	87570.6	-134.934	-0.15%	(0.86)
2018Q4	88710	88651.6	58.4304	0.07%	0.37
2019Q1	89285	89202.2	82.8088	0.09%	0.53
2019Q2	88955	88754.7	200.312	0.23%	1.28
2019Q3	88394	88353.4	40.6438	0.05%	0.26
2019Q4	89508.7	89525.3	-16.5976	-0.02%	(0.11)
2020Q1	90104	90003.3	100.665	0.11%	0.64
2020Q2	90319.3	90117.5	201.832	0.22%	1.29
2020Q3	90310.7	90125	185.627	0.21%	1.19
2020Q4	90531	90384	146.988	0.16%	0.94
2021Q1	90793.7	90786.5	7.14522	0.01%	0.05
2021Q2	90744.3	90966.3	-221.921	-0.24%	(1.42)
2021Q3	90765.3	91010.2	-244.877	-0.27%	(1.56)
2021Q4	91173.3	91260.9	-87.593	-0.10%	(0.56)
2022Q1	91521.7	91517.2	4.44382	0.00%	0.03
2022Q2	91882.3	91882.3	3.7E-09	0.00%	0.00
2022Q3	88853	88853	3.2E-09	0.00%	0.00

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	91173.33	91277.81	-104.48	-0.1%
Q1 2022	91521.67	91535.36	-13.69	0.0%
Q2 2022	91882.33	91569.73	312.60	0.3%
Q3 2022	88853	91800.82	-2947.82	-3.3%
Total	363430.33	366183.72	-2753.39	-0.8%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	56652.51	55833.97	818.54	1%
S_CUMULATIV_HC(-3)	0.280418	0.287158	-0.00674	-2%
S_Q2_D2016_D2019	-365.999	-359.8641	-6.1349	2%
S_D22Q3	-2751.477	0	-2751.477	100%
S_Q3_D2015_D2019	-801.4067	-797.9325	-3.4742	0%
S_D15Q4	-243.849	-242.4727	-1.3763	1%
S_D22Q2	333.37	0	333.37	100%
AR(4)	0.674285	0.669442	0.004843	1%

RNHC Brockton S&T
B. Residential Non-Heating Customers - Sales and Transportation
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
B_RNH_CUST_S_T	8	0.998	5.529

ARIMA Model Parameters

B_RNH_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	10747.44	36.054	298.09	0.000
	@TREND	-54.17471	0.661	-81.99	0.000
	B_D20Q3	143.0595	31.618	4.52	0.000
	B_D14Q3	391.5331	32.856	11.92	0.000
	B_D18Q1	-61.68762	31.174	-1.98	0.059
	B_D14Q4	361.7078	32.652	11.08	0.000
	B_D20Q4	189.9009	31.738	5.98	0.000
	B_D21Q1+B_D21Q2	95.3296	23.518	4.05	0.000

Variable	Definition	Explanation	Dummy Variable Support
@TREND	Quarterly Trend		
B_D20Q3	Binary variable equal to 1 in 2020Q3		2
B_D14Q3	Binary variable equal to 1 in 2014Q3		2
B_D18Q1	Binary variable equal to 1 in 2018Q1		2
B_D14Q4	Binary variable equal to 1 in 2014Q4		2
B_D20Q4	Binary variable equal to 1 in 2020Q4		2
B_D21Q1+B_D21Q2	Binary variable equal to 1 in 2021Q1 and 2021Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

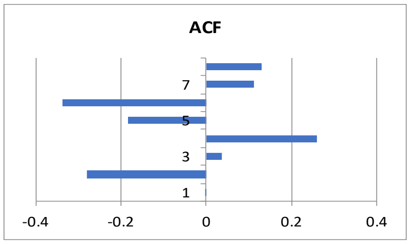
N	Adjusted R2	F Statistic
33	0.996964	1502.197

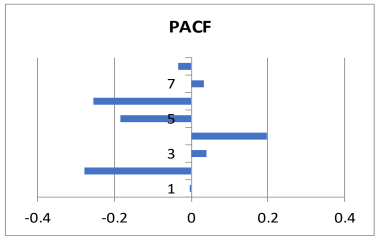
Chow Test Stats	N	k	SSR
Combined	33	8	23,361.68
1	14	4	6,693.25
2	19	6	12,043.45

Chow Stat:	0.525
P-Value:	0.822066

Heteroscedasticity - White's Test	
White Stat	0.87
Significance (p-value)	0.54

Correlations	@TREND	B_D20Q3	B_D14Q3	B_D18Q1	B_D14Q4	B_D20Q4	B_D21Q1+B_D21Q2
@TREND	1	0.148522	-0.297044	-0.037131	-0.27848	0.167087	0.280091
B_D20Q3	0.148522	1	-0.03125	-0.03125	-0.03125	-0.03125	-0.044901
B_D14Q3	-0.297044	-0.03125	1	-0.03125	-0.03125	-0.03125	-0.044901
B_D18Q1	-0.037131	-0.03125	-0.03125	1	-0.03125	-0.03125	-0.044901
B_D14Q4	-0.278479	-0.03125	-0.03125	-0.03125	1	-0.03125	-0.044901
B_D20Q4	0.167087	-0.03125	-0.03125	-0.03125	-0.03125	1	-0.044901
B_D21Q1+B_D21Q2	0.280091	-0.044901	-0.044901	-0.044901	-0.0449	-0.044901	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_rnh_cust_s_t Model	ACF	-0.002	-0.279	0.037	0.261	-0.183	-0.336	0.113	0.131
	SE	0.348	0.348	0.348	0.348	0.348	0.348	0.348	0.348
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_rnh_cust_s_t Model		-0.002	-0.279	0.039	0.198	-0.186	-0.254	0.032	-0.033
	SE	0.348	0.348	0.348	0.348	0.348	0.348	0.348	0.348

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2014Q3	9080.33	9080.33	-1.1E-13	0.00%	(0.00)
2014Q4	8996.33	8996.33	-1.7E-13	0.00%	(0.00)
2015Q1	8609.67	8580.45	29.2159	0.34%	0.96
2015Q2	8527.33	8526.28	1.05723	0.01%	0.03
2015Q3	8473	8472.1	0.89861	0.01%	0.03
2015Q4	8466.33	8417.93	48.4067	0.57%	1.58
2016Q1	8331	8363.75	-32.752	-0.39%	(1.07)
2016Q2	8287.33	8309.58	-22.2439	-0.27%	(0.73)
2016Q3	8237.67	8255.4	-17.7359	-0.22%	(0.58)
2016Q4	8224.67	8201.23	23.4388	0.28%	0.77
2017Q1	8143	8147.05	-4.05313	-0.05%	(0.13)
2017Q2	8102.33	8092.88	9.45492	0.12%	0.31
2017Q3	8051.33	8038.7	12.6296	0.16%	0.41
2017Q4	8023	7984.53	38.471	0.48%	1.26
2018Q1	7868.67	7868.67	7.8E-13	0.00%	(0.00)
2018Q2	7814	7876.18	-62.1796	-0.80%	(2.03)
2018Q3	7804	7822	-18.0049	-0.23%	(0.59)
2018Q4	7778	7767.83	10.1698	0.13%	0.33
2019Q1	7674	7713.66	-39.6554	-0.52%	(1.30)
2019Q2	7620.33	7659.48	-39.1474	-0.51%	(1.28)
2019Q3	7594	7605.31	-11.306	-0.15%	(0.37)
2019Q4	7584.67	7551.13	33.5354	0.44%	1.10
2020Q1	7466.67	7496.96	-30.2899	-0.41%	(0.99)
2020Q2	7470.67	7442.78	27.8848	0.37%	0.91
2020Q3	7531.67	7531.67	2.6E-13	0.00%	(0.00)
2020Q4	7524.33	7524.33	-2.8E-13	0.00%	(0.00)
2021Q1	7363.67	7375.59	-11.9207	-0.16%	(0.39)
2021Q2	7333.33	7321.41	11.9207	0.16%	0.39
2021Q3	7214.67	7171.91	42.7583	0.59%	1.40
2021Q4	7087	7117.73	-30.7336	-0.43%	(1.01)
2022Q1	7034.67	7063.56	-28.8923	-0.41%	(0.95)
2022Q2	7037.67	7009.38	28.2825	0.40%	0.93
2022Q3	6986	6955.21	30.7905	0.44%	1.01

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	7087	7116.176	-29.18	-0.4%
Q1 2022	7034.667	7061.901	-27.23	-0.4%
Q2 2022	7037.667	7007.627	30.04	0.4%
Q3 2022	6986	6953.352	32.65	0.5%
Total	28145.33	28139.06	6.28	0.0%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	10747.44	10752.57	-5.13	0%
@TREND	-54.17471	-54.2745	0.09979	0%
B_D20Q3	143.0595	144.1184	-1.0589	-1%
B_D14Q3	391.5331	390.1971	1.336	0%
B_D18Q1	-61.68762	-61.62657	-0.06105	0%
B_D14Q4	361.7078	360.4716	1.2362	0%
B_D20Q4	189.9009	191.0596	-1.1587	-1%
B_D21Q1+B_D21Q2	95.3296	96.638	-1.3084	-1%

RNHC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
L_RNH_CUST_S_T	8	0.996	3.438

ARIMA Model Parameters

L_RNH_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	3469.277	16.288	212.99	0.000
	@TREND	-18.7144	0.286	-65.44	0.000
	L_D18Q3	-180.3661	12.103	-14.90	0.000
	L_D18Q4	-264.3183	12.091	-21.86	0.000
	L_D20Q4	44.7302	12.237	3.66	0.002
	L_D20Q3	38.68247	12.196	3.17	0.005
	L_D19Q4	31.87261	12.110	2.63	0.016
	L_D17Q4	31.82407	12.179	2.61	0.017

Variable	Definition	Explanation	Dummy Variable Support
@TREND	Quarterly Trend		
L_D18Q3	Binary variable equal to 1 in 2018Q3		2
L_D18Q4	Binary variable equal to 1 in 2018Q4		2
L_D20Q4	Binary variable equal to 1 in 2020Q4		2
L_D20Q3	Binary variable equal to 1 in 2020Q3		2
L_D19Q4	Binary variable equal to 1 in 2019Q4		2
L_D17Q4	Binary variable equal to 1 in 2017Q4		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
28	0.994615	713.3764

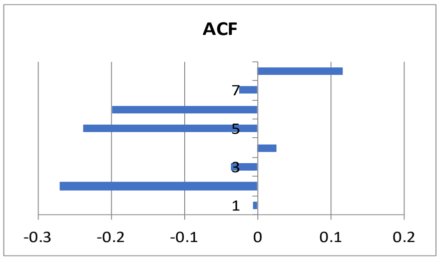
Chow Test Stats	N	k	SSR
Combined	28	8	2,794.09
1	15	5	1,981.83
2	13	5	364.54

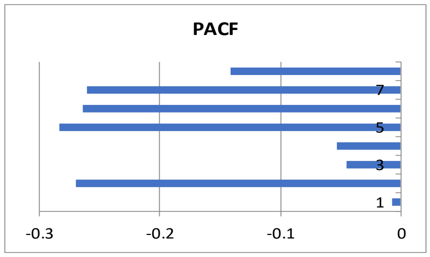
Chow Stat:	0.286
P-Value:	0.957774

Heteroscedasticity - White's Test	
White Stat	0.95
Significance (p-value)	0.49

Correlations

	@TREND	L_D18Q3	L_D18Q4	L_D20Q4	L_D20Q3	L_D19Q4	L_D17Q4
@TREND	1	-0.059562	-0.035737	0.154861	0.131036	0.059562	-0.13104
L_D18Q3	-0.059562	1	-0.037037	-0.037037	-0.03704	-0.037037	-0.03704
L_D18Q4	-0.035737	-0.037037	1	-0.037037	-0.03704	-0.037037	-0.03704
L_D20Q4	0.154861	-0.037037	-0.037037	1	-0.03704	-0.037037	-0.03704
L_D20Q3	0.131036	-0.037037	-0.037037	-0.037037	1	-0.037037	-0.03704
L_D19Q4	0.059562	-0.037037	-0.037037	-0.037037	-0.03704	1	-0.03704
L_D17Q4	-0.131036	-0.037037	-0.037037	-0.037037	-0.03704	-0.037037	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_rnh_cust_s_t Model	ACF	-0.007	-0.27	-0.037	0.025	-0.239	-0.199	-0.026	0.116
	SE	0.378	0.378	0.378	0.378	0.378	0.378	0.378	0.378
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_rnh_cust_s_t Model		-0.007	-0.27	-0.045	-0.053	-0.284	-0.264	-0.261	-0.142
	SE	0.378	0.378	0.378	0.378	0.378	0.378	0.378	0.378

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2015Q4	2696.33	2664.56	31.7755	1.18%	2.69
2016Q1	2637.67	2645.84	-8.17672	-0.31%	(0.69)
2016Q2	2610	2627.13	-17.129	-0.66%	(1.45)
2016Q3	2598.67	2608.41	-9.74792	-0.38%	(0.82)
2016Q4	2600	2589.7	10.2998	0.40%	0.87
2017Q1	2559.33	2570.99	-11.6525	-0.46%	(0.99)
2017Q2	2545.67	2552.27	-6.60473	-0.26%	(0.56)
2017Q3	2541	2533.56	7.44301	0.29%	0.63
2017Q4	2546.67	2546.67	6E-14	0.00%	0.00
2018Q1	2506.67	2496.13	10.5385	0.42%	0.89
2018Q2	2471.67	2477.41	-5.74713	-0.23%	(0.49)
2018Q3	2278.33	2278.33	2.3E-13	0.00%	0.00
2018Q4	2175.67	2175.67	5.7E-14	0.00%	0.00
2019Q1	2409.33	2421.27	-11.9373	-0.50%	(1.01)
2019Q2	2390.33	2402.56	-12.2229	-0.51%	(1.03)
2019Q3	2393.67	2383.84	9.82487	0.41%	0.83
2019Q4	2397	2397	5.9E-13	0.00%	0.00
2020Q1	2352.67	2346.41	6.25367	0.27%	0.53
2020Q2	2340.67	2327.7	12.9681	0.55%	1.10
2020Q3	2347.67	2347.67	1.5E-13	0.00%	0.00
2020Q4	2335	2335	-2.1E-14	0.00%	0.00
2021Q1	2274.67	2271.56	3.11127	0.14%	0.26
2021Q2	2251.67	2252.84	-1.17433	-0.05%	(0.10)
2021Q3	2228	2234.13	-6.1266	-0.27%	(0.52)
2021Q4	2205	2215.41	-10.4122	-0.47%	(0.88)
2022Q1	2195	2196.7	-1.6978	-0.08%	(0.14)
2022Q2	2187.33	2177.98	9.34994	0.43%	0.79
2022Q3	2160.33	2159.27	1.06434	0.05%	0.09

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	2205	2215.542	-10.54	-0.5%
Q1 2022	2195	2196.831	-1.83	-0.1%
Q2 2022	2187.333	2178.119	9.21	0.4%
Q3 2022	2160.333	2159.407	0.93	0.0%
Total	8747.67	8749.90	-2.23	0.0%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	3469.277	3469.228	0.049	0%
@TREND	-18.7144	-18.71172	-0.00268	0%
L_D18Q3	-180.3661	-180.4615	0.0954	0%
L_D18Q4	-264.3183	-264.4164	0.0981	0%
L_D20Q4	44.7302	44.61072	0.11948	0%
L_D20Q3	38.68247	38.56566	0.11681	0%
L_D19Q4	31.87261	31.76383	0.10878	0%
L_D17Q4	31.82407	31.73671	0.08736	0%

RNHC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
S_RNH_CUST_S_T	5	0.991	6.629

ARIMA Model Parameters

S_RNH_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	12765.68	184.286	69.27	0.000
	@TREND	-61.87065	2.869	-21.56	0.000
	S_D14Q1_D17Q1	-204.8526	60.108	-3.41	0.002
	S_D17Q2_D19Q3	-133.0668	36.633	-3.63	0.001
	S_D20Q4_D21Q2	131.4861	29.746	4.42	0.000

Variable	Definition	Explanation	Dummy Variable Support
@TREND	Quarterly Trend		
S_D14Q1_D17Q1	Binary variable equal to 1 from 2014Q1 to 2017Q1		1
S_D17Q2_D19Q3	Binary variable equal to 1 from 2017Q2 to 2019Q3		1
S_D20Q4_D21Q2	Binary variable equal to 1 from 2020Q4 to 2021Q2		1

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

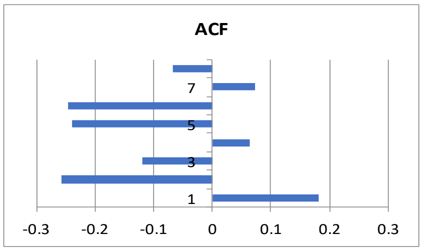
N	Adjusted R2	F Statistic
29	0.989873	685.2099

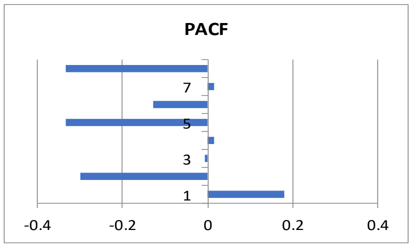
Chow Test Stats	N	k	SSR
Combined	30	5	118,173.29
1	19	4	24,687.77
2	11	3	83,615.04

Chow Stat:	0.365
P-Value:	0.866725

Heteroscedasticity - White's Test	
White Stat	1.61
Significance (p-value)	0.21

Correlations	@TREND	S_D14Q1_D17Q1	S_D17Q2_D19Q3	S_D20Q4_D21Q2
@TREND	1	-0.774597	-0.130066	0.365399
S_D14Q1_D17Q1	-0.774597	1	-0.447774	-0.209657
S_D17Q2_D19Q3	-0.130066	-0.447774	1	-0.246432
S_D20Q4_D21Q2	0.365399	-0.209657	-0.246432	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_rnh_cust_s_t Model	ACF	0.181	-0.257	-0.119	0.063	-0.24	-0.247	0.073	-0.068
	SE	0.371	0.371	0.371	0.371	0.371	0.371	0.371	0.371
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_rnh_cust_s_t Model		0.181	-0.299	-0.005	0.017	-0.335	-0.127	0.016	-0.334
	SE	0.371	0.371	0.371	0.371	0.371	0.371	0.371	0.371

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2015Q2	10080.3	10024.1	56.2027	0.56%	1.28
2015Q3	9968.67	9962.26	6.40672	0.06%	0.15
2015Q4	9919.33	9900.39	18.944	0.19%	0.43
2016Q1	9780.33	9838.52	-58.1853	-0.59%	(1.32)
2016Q2	9729.33	9776.65	-47.3147	-0.49%	(1.08)
2016Q3	9685.33	9714.78	-29.444	-0.30%	(0.67)
2016Q4	9671.33	9652.91	18.4266	0.19%	0.42
2017Q1	9626	9591.04	34.9639	0.36%	0.80
2017Q2	9573.67	9600.95	-27.2846	-0.28%	(0.62)
2017Q3	9541.33	9539.08	2.25274	0.02%	0.05
2017Q4	9567	9477.21	89.79	0.94%	2.04
2018Q1	9430	9415.34	14.6607	0.16%	0.33
2018Q2	9332.33	9353.47	-21.1353	-0.23%	(0.48)
2018Q3	9266.33	9291.6	-25.2647	-0.27%	(0.58)
2018Q4	9272.67	9229.73	42.9393	0.46%	0.98
2019Q1	9161.67	9167.86	-6.19005	-0.07%	(0.14)
2019Q2	9057.67	9105.99	-48.3194	-0.53%	(1.10)
2019Q3	9022.67	9044.12	-21.4488	-0.24%	(0.49)
2019Q4	9052.33	9115.31	-62.9782	-0.70%	(1.43)
2020Q1	8993.33	9053.44	-60.1076	-0.67%	(1.37)
2020Q2	9003.33	8991.57	11.7631	0.13%	0.27
2020Q3	9016	8929.7	86.3004	0.96%	1.96
2020Q4	9000.33	8999.32	1.01824	0.01%	0.02
2021Q1	8936.33	8937.44	-1.11111	-0.01%	(0.03)
2021Q2	8875.67	8875.57	0.09287	0.00%	0.00
2021Q3	8716.67	8682.22	34.4496	0.40%	0.78
2021Q4	8576.67	8620.35	-43.6797	-0.51%	(0.99)
2022Q1	8552.33	8558.48	-6.14241	-0.07%	(0.14)
2022Q2	8537	8496.61	40.3949	0.47%	0.92

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	8716.667	8667.478	49.19	0.6%
Q1 2022	8576.667	8604.064	-27.40	-0.3%
Q2 2022	8552.333	8540.651	11.68	0.1%
Q3 2022	8537	8477.238	59.76	0.7%
Total	34382.67	34289.43	93.24	0.3%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	12765.68	12852.75	-87.07	-1%
@TREND	-61.87065	-63.41318	1.54253	-2%
S_D14Q1_D17Q1	-204.8526	-223.2776	18.425	-9%
S_D17Q2_D19Q3	-133.0668	-137.6089	4.5421	-3%
S_D20Q4_D21Q2	131.4861	143.1406	-11.6545	-9%

LLFC Brockton S&T
C. Low Load Factor Customers - Sales and Transportation
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
B_LLF_CUST_S_T	11	0.970	9.601

ARIMA Model Parameters

B_LLF_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	12763.79	617.241	20.68	0.000
	B_GMP(-3)	4.191045	1.222	3.43	0.002
	Q3	-280.4617	25.742	-10.90	0.000
	B_D20Q2+B_D20Q3	254.0344	71.849	3.54	0.002
	B_D21Q4	-234.6384	82.492	-2.84	0.008
	B_D22Q1	-295.5459	85.566	-3.45	0.002
	Q1	273.9673	26.878	10.19	0.000
	B_D16Q4_17Q2	-176.7979	73.724	-2.40	0.024
	B_D13Q4	166.9824	72.593	2.30	0.029
	B_D18Q4	173.6032	72.363	2.40	0.024
	AR(1)	0.858518	0.073	11.72	0.000

Variable	Definition	Explanation	Dummy Variable Support
B_GMP(-3)	Gross Metro Product (bil. $) in Brockton lagged three quarters		
Q3	Binary variable equal to 1 in Q3	C	2
B_D20Q2+B_D20Q3	Binary variable equal to 1 in 2020Q2 and 2020Q3		2
B_D21Q4	Binary variable equal to 1 in 2021Q4		2
B_D22Q1	Binary variable equal to 1 in 2022Q1		2
Q1	Binary variable equal to 1 in Q1	C	2
B_D16Q4_17Q2	Binary variable equal to 1 from 2016Q4 to 2017Q2		2
B_D13Q4	Binary variable equal to 1 in 2013Q4		2
B_D18Q4	Binary variable equal to 1 in 2018Q4		2
AR(1)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

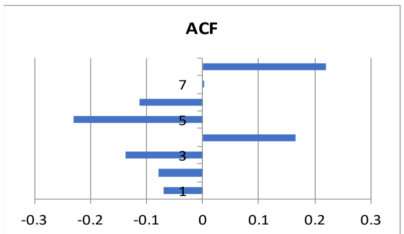
N	Adjusted R2	F Statistic
38	0.958888	87.29766

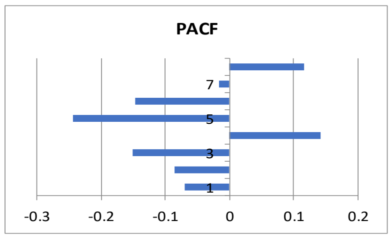
Chow Test Stats	N	k	SSR
Combined	38	11	229,408.27
1	16	8	69,173.52
2	22	11	69,289.66

Chow Stat:	0.955
P-Value:	0.518437

Heteroscedasticity - White's Test	
White Stat	0.50
Significance (p-value)	0.87

Correlations									
	B_GMP(-3)	Q3	B_D20Q2+B_D20Q3	B_D21Q4	B_D22Q1	Q1	B_D16Q4_17Q2	B_D13Q4	B_D18Q4
B_GMP(-3)	1	0.060366	0.250114	0.23254	0.275086	-0.031353	-0.101022	-0.2216	0.047207
Q3	0.060366	1	0.126773	-0.098247	-0.09825	-0.332923	-0.174964	-0.09825	-0.09825
B_D20Q2+B_D20Q3	0.250114	0.126773	1	-0.038749	-0.03875	-0.131306	-0.069007	-0.03875	-0.03875
B_D21Q4	0.23254	-0.098247	-0.038749	1	-0.02703	-0.091584	-0.048131	-0.02703	-0.02703
B_D22Q1	0.275086	-0.098247	-0.038749	-0.027027	1	0.295105	-0.048131	-0.02703	-0.02703
Q1	-0.031353	-0.332923	-0.131306	-0.091584	0.295105	1	0.066447	-0.09158	-0.09158
B_D16Q4_17Q2	-0.101022	-0.174964	-0.069007	-0.048131	-0.04813	0.066447	1	-0.04813	-0.04813
B_D13Q4	-0.221598	-0.098247	-0.038749	-0.027027	-0.02703	-0.091584	-0.048131	1	-0.02703
B_D18Q4	0.047207	-0.098247	-0.038749	-0.027027	-0.02703	-0.091584	-0.048131	-0.02703	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_llf_cust_s_t Model	ACF	-0.07	-0.079	-0.137	0.166	-0.23	-0.113	0.001	0.219
	SE	0.324	0.324	0.324	0.324	0.324	0.324	0.324	0.324
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_llf_cust_s_t Model		-0.07	-0.085	-0.151	0.141	-0.244	-0.147	-0.017	0.116
	SE	0.324	0.324	0.324	0.324	0.324	0.324	0.324	0.324

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2013Q2	13370	13514.7	-144.724	-1.08%	(1.57)
2013Q3	13257.3	13215.1	42.1995	0.32%	0.46
2013Q4	13871.3	13818.1	53.259	0.38%	0.58
2014Q1	14120.3	14058.3	62.0367	0.44%	0.67
2014Q2	13843.3	13916.7	-73.3243	-0.53%	(0.80)
2014Q3	13588.7	13638.3	-49.6521	-0.37%	(0.54)
2014Q4	14106	13925.8	180.225	1.28%	1.96
2015Q1	14350	14429.9	-79.8904	-0.56%	(0.87)
2015Q2	14081.3	14134.3	-52.9585	-0.38%	(0.57)
2015Q3	13866	13862.8	3.20483	0.02%	0.03
2015Q4	14311	14197.7	113.334	0.79%	1.23
2016Q1	14579.7	14629.9	-50.19	-0.34%	(0.54)
2016Q2	14371.7	14335.9	35.7461	0.25%	0.39
2016Q3	14006.3	14102.6	-96.3162	-0.69%	(1.04)
2016Q4	14082	14145.1	-63.0528	-0.45%	(0.68)
2017Q1	14294.3	14402.8	-108.471	-0.76%	(1.18)
2017Q2	14066.7	14075.8	-9.11358	-0.06%	(0.10)
2017Q3	13910	14002.8	-92.8237	-0.67%	(1.01)
2017Q4	14321	14243.7	77.3163	0.54%	0.84
2018Q1	14565.7	14626.3	-60.6021	-0.42%	(0.66)
2018Q2	14324.3	14346.2	-21.8489	-0.15%	(0.24)
2018Q3	14201.3	14111.8	89.5204	0.63%	0.97
2018Q4	14742.3	14700.3	42.0736	0.29%	0.46
2019Q1	14931.7	14882.7	49.0077	0.33%	0.53
2019Q2	14667	14669.5	-2.54899	-0.02%	(0.03)
2019Q3	14440.7	14397	43.6587	0.30%	0.47
2019Q4	14655.3	14732.4	-77.0911	-0.53%	(0.84)
2020Q1	14834.7	14962.2	-127.567	-0.86%	(1.38)
2020Q2	14858.7	14869.7	-10.997	-0.07%	(0.12)
2020Q3	14801.7	14642.5	159.129	1.08%	1.73
2020Q4	14846.7	14833.2	13.4167	0.09%	0.15
2021Q1	14957	14870.2	86.7716	0.58%	0.94
2021Q2	14886.3	14873.2	13.1392	0.09%	0.14
2021Q3	14661.7	14614.5	47.1937	0.32%	0.51
2021Q4	14708.7	14739.6	-30.911	-0.21%	(0.34)
2022Q1	14927.3	14963.3	-36.0055	-0.24%	(0.39)
2022Q2	14931.7	14973.6	-41.9396	-0.28%	(0.45)
2022Q3	14845	14726.2	118.796	0.80%	1.29

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	14708.67	14933.95	-225.28	-1.5%
Q1 2022	14927.33	15245.32	-317.99	-2.1%
Q2 2022	14931.67	14994.57	-62.90	-0.4%
Q3 2022	14845	14762.69	82.31	0.6%
Total	59412.67	59936.53	-523.86	-0.9%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	12763.79	12963.03	-199.24	-2%
B_GMP(-3)	4.191045	3.810018	0.381027	9%
Q3	-280.4617	-292.4471	11.9854	-4%
B_D20Q2+B_D20Q3	254.0344	259.4578	-5.4234	-2%
B_D21Q4	-234.6384	0	-234.6384	
B_D22Q1	-295.5459	0	-295.5459	
Q1	273.9673	270.778	3.1893	1%
B_D16Q4_17Q2	-176.7979	-187.3976	10.5997	-6%
B_D13Q4	166.9824	160.8744	6.108	4%
B_D18Q4	173.6032	165.7591	7.8441	5%
AR(1)	0.858518	0.874673	-0.016155	-2%

LLFC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
L_LLF_CUST_S_T	9	0.945	5.926

ARIMA Model Parameters

L_LLF_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	4855.735	54.713	88.75	0.000
	L_LLFNGP_ST_ROLL12	-150.9493	4.244	-35.57	0.000
	L_AFT_D21Q3	-127.0368	13.300	-9.55	0.000
	L_D16Q1	98.38065	28.066	3.51	0.001
	L_D15Q1	58.73617	28.077	2.09	0.042
	L_D18Q3+L_D18Q4	-232.6476	21.198	-10.98	0.000
	L_D16Q2	111.9859	28.178	3.97	0.000
	L_D2010	-42.03181	13.607	-3.09	0.004
	AR(2)	-0.817717	0.096	-8.55	0.000

Variable	Definition	Explanation	Dummy Variable Support
L_LLFNGP_ST_ROLL12	Rolling 12 quarter natural gas price for low load factor customers in Lawrence ($2022/MMBtu)		
L_AFT_D21Q3	Binary variable equal to 1 from 2021Q3 on		1
L_D16Q1	Binary variable equal to 1 in 2016Q1		2
L_D15Q1	Binary variable equal to 1 in 2015Q1		2
L_D18Q3+L_D18Q4	Binary variable equal to 1 in 2018Q3 and 2018Q4		2
L_D16Q2	Binary variable equal to 1 in 2016Q2		2
L_D2010	Binary variable equal to 1 in 2010		2
AR(2)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
52	0.934239	91.5663

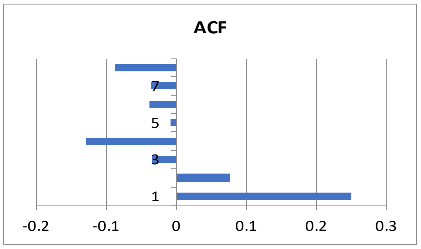
Chow Test Stats	N	k	SSR
Combined	52	9	53,015.93
1	28	7	18,879.46
2	24	5	28,174.75

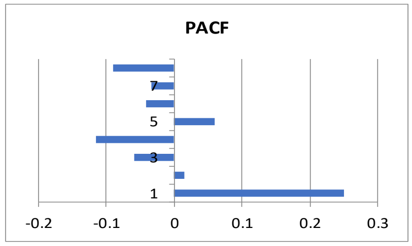
Chow Stat:	0.479
P-Value:	0.878689

Heteroscedasticity - White's Test	
White Stat	1.70
Significance (p-value)	0.13

Correlations

	L_LLFNGP_ST_ROLL12	L_AFT_D21Q3	L_D16Q1	L_D15Q1	L_D18Q3+	L_D16Q2	L_D2010
L_LLFNGP_ST_ROLL12	1	-0.545262	0.027876	0.055165	-0.12853	0.016216	0.400653
L_AFT_D21Q3	-0.545262	1	-0.045672	-0.045672	-0.06523	-0.045672	-0.09416
L_D16Q1	0.027876	-0.045672	1	-0.019608	-0.02801	-0.019608	-0.04042
L_D15Q1	0.055165	-0.045672	-0.019608	1	-0.02801	-0.019608	-0.04042
L_D18Q3+L_D18Q4	-0.128527	-0.065233	-0.028006	-0.028006	1	-0.028006	-0.05774
L_D16Q2	0.016216	-0.045672	-0.019608	-0.019608	-0.02801	1	-0.04042
L_D2010	0.400653	-0.094155	-0.040423	-0.040423	-0.05774	-0.040423	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_llf_cust_s_t	ACF	0.25	0.076	-0.034	-0.129	-0.008	-0.038	-0.036	-0.088
	SE	0.277	0.277	0.277	0.277	0.277	0.277	0.277	0.277
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_llf_cust_s_t		0.25	0.014	-0.06	-0.115	0.06	-0.041	-0.033	-0.09
	SE	0.277	0.277	0.277	0.277	0.277	0.277	0.277	0.277

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2009Q4	2722.67	2752.15	-29.4858	-1.08%	(0.84)
2010Q1	2786.33	2783.76	2.56863	0.09%	0.07
2010Q2	2697	2700.05	-3.04838	-0.11%	(0.09)
2010Q3	2629.67	2628.49	1.17461	0.04%	0.03
2010Q4	2730.33	2713.67	16.6648	0.61%	0.47
2011Q1	2810	2822.04	-12.0394	-0.43%	(0.34)
2011Q2	2722	2749.03	-27.0294	-0.99%	(0.77)
2011Q3	2697.33	2725.89	-28.5556	-1.06%	(0.81)
2011Q4	2798.67	2809.54	-10.8763	-0.39%	(0.31)
2012Q1	2887.33	2842.76	44.5753	1.54%	1.27
2012Q2	2823.67	2776.78	46.8858	1.66%	1.34
2012Q3	2756.67	2722.41	34.2576	1.24%	0.98
2012Q4	2798	2791	6.99596	0.25%	0.20
2013Q1	2863.33	2861.46	1.87544	0.07%	0.05
2013Q2	2780.33	2840.85	-60.5176	-2.18%	(1.72)
2013Q3	2753.33	2801.33	-47.9922	-1.74%	(1.37)
2013Q4	2881.33	2882.48	-1.15004	-0.04%	(0.03)
2014Q1	2943.67	2918.72	24.9425	0.85%	0.71
2014Q2	2850	2828	22.0023	0.77%	0.63
2014Q3	2792.67	2791.26	1.40231	0.05%	0.04
2014Q4	2925.33	2880.93	44.4061	1.52%	1.26
2015Q1	3010.33	2997.84	12.4932	0.42%	0.36
2015Q2	2874.67	2841.85	32.8204	1.14%	0.93
2015Q3	2815.33	2830.61	-15.2782	-0.54%	(0.44)
2015Q4	2974	2905.17	68.8345	2.31%	1.96
2016Q1	3051.33	3064.64	-13.3019	-0.44%	(0.38)
2016Q2	2995.67	2965.55	30.1207	1.01%	0.86
2016Q3	2904.67	2888.4	16.2672	0.56%	0.46
2016Q4	2927.67	2964.5	-36.8353	-1.26%	(1.05)
2017Q1	2981.67	2965.6	16.0657	0.54%	0.46
2017Q2	2923	2962.81	-39.8127	-1.36%	(1.13)
2017Q3	2861	2934.09	-73.0926	-2.55%	(2.08)
2017Q4	2973.33	2998.26	-24.9253	-0.84%	(0.71)
2018Q1	3040.67	3068.48	-27.8139	-0.91%	(0.79)
2018Q2	2955	2998.18	-43.1774	-1.46%	(1.23)
2018Q3	2727.33	2734.7	-7.36241	-0.27%	(0.21)
2018Q4	2806	2828.19	-22.1885	-0.79%	(0.63)
2019Q1	3087.67	3079.89	7.77352	0.25%	0.22
2019Q2	3063.67	3035.3	28.365	0.93%	0.81
2019Q3	3000.67	3014.26	-13.5887	-0.45%	(0.39)
2019Q4	3065.33	3052.66	12.6777	0.41%	0.36
2020Q1	3110	3123.38	-13.3833	-0.43%	(0.38)
2020Q2	3120.67	3090.26	30.4109	0.97%	0.87
2020Q3	3111	3074.08	36.9236	1.19%	1.05
2020Q4	3106.33	3083.63	22.7016	0.73%	0.65
2021Q1	3123.67	3108.32	15.3457	0.49%	0.44
2021Q2	3103.67	3127.97	-24.3005	-0.78%	(0.69)
2021Q3	2991	3001.56	-10.5569	-0.35%	(0.30)
2021Q4	3038.67	3034.32	4.34275	0.14%	0.12
2022Q1	3118.33	3041.75	76.5838	2.46%	2.18
2022Q2	3020.33	3025.36	-5.03088	-0.17%	(0.14)
2022Q3	2917.67	2985.8	-68.1343	-2.34%	(1.94)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	3038.667	3022.167	16.50	0.5%
Q1 2022	3118.333	3021.014	97.32	3.1%
Q2 2022	3020.333	3019.404	0.93	0.0%
Q3 2022	2917.667	3045.191	-127.52	-4.4%
Total	12095.00	12107.78	-12.78	-0.1%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	4855.735	4859.567	-3.832	0%
L_LLFNGP_ST_ROLL12	-150.9493	-151.2403	0.291	0%
L_AFT_D21Q3	-127.0368	-138.8387	11.8019	-9%
L_D16Q1	98.38065	99.0516	-0.67095	-1%
L_D15Q1	58.73617	59.94092	-1.20475	-2%
L_D18Q3+L_D18Q4	-232.6476	-233.5471	0.8995	0%
L_D16Q2	111.9859	111.2457	0.7402	1%
L_D2010	-42.03181	-41.61314	-0.41867	1%
AR(2)	-0.817717	-0.75966	-0.058057	7%

LLFC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
S_LLF_CUST_S_T	10	0.873	7.743

ARIMA Model Parameters

S_LLF_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	7382.808	112.822	65.44	0.000
	S_GMP(-1)	21.35116	3.149	6.78	0.000
	S_D2020+S_D21Q1	162.0298	21.286	7.61	0.000
	S_D22Q3	-344.1358	72.777	-4.73	0.000
	S_D22Q2	-201.074	70.656	-2.85	0.010
	S_D17Q3	-140.239	56.020	-2.50	0.021
	S_D19Q2	123.7813	52.035	2.38	0.027
	S_D17Q2	-201.1034	51.049	-3.94	0.001
	S_D17Q1	-118.3896	56.400	-2.10	0.048
	AR(2)	-0.756841	0.110	-6.85	0.000

Variable	Definition	Explanation	Dummy Variable Support
S_GMP(-1)	Gross Metro Product (bil. $) in Springfield		
S_D2020+S_D21Q1	Binary variable equal to 1 in 2020 and 2021Q1		2
S_D22Q3	Binary variable equal to 1 in 2022Q3		2
S_D22Q2	Binary variable equal to 1 in 2022Q2		2
S_D17Q3	Binary variable equal to 1 in 2017Q3		2
S_D19Q2	Binary variable equal to 1 in 2019Q2		2
S_D17Q2	Binary variable equal to 1 in 2017Q2		2
S_D17Q1	Binary variable equal to 1 in 2017Q1		2
AR(2)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
31	0.819274	16.11079

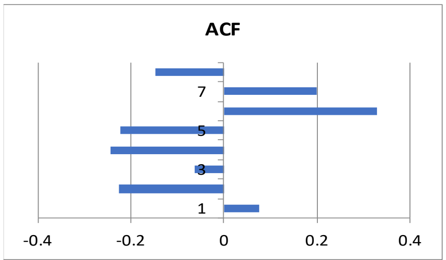
Chow Test Stats	N	k	SSR
Combined	31	10	75,478.98
1	15	6	27,606.62
2	16	7	24,036.96

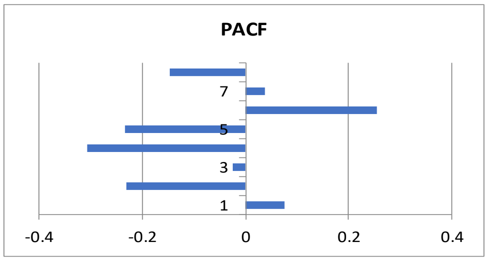
Chow Stat:	0.508
P-Value:	0.852247

Heteroscedasticity - White's Test	
White Stat	0.67
Significance (p-value)	0.73

Correlations

	S_GMP(-1)	S_D2020+S_D21Q1	S_D22Q3	S_D22Q2	S_D17Q3	S_D19Q2	S_D17Q2	S_D17Q1
S_GMP(-1)	1	0.096978	0.421998	0.371113	-0.12011	0.048287	-0.13648	-0.13641
S_D2020+S_D21Q1	0.096978	1	-0.080064	-0.080064	-0.08006	-0.080064	-0.08006	-0.08006
S_D22Q3	0.421998	-0.080064	1	-0.033333	-0.03333	-0.033333	-0.03333	-0.03333
S_D22Q2	0.371113	-0.080064	-0.033333	1	-0.03333	-0.033333	-0.03333	-0.03333
S_D17Q3	-0.120105	-0.080064	-0.033333	-0.033333	1	-0.033333	-0.03333	-0.03333
S_D19Q2	0.048287	-0.080064	-0.033333	-0.033333	-0.03333	1	-0.03333	-0.03333
S_D17Q2	-0.136478	-0.080064	-0.033333	-0.033333	-0.03333	-0.033333	1	-0.03333
S_D17Q1	-0.136413	-0.080064	-0.033333	-0.033333	-0.03333	-0.033333	-0.03333	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_llf_cust_s_t Model	ACF	0.077	-0.225	-0.062	-0.245	-0.224	0.328	0.199	-0.148
	SE	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_llf_cust_s_t Model		0.077	-0.232	-0.024	-0.307	-0.233	0.255	0.038	-0.147
	SE	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2015Q1	8239	8260.51	-21.5113	-0.26%	(0.36)
2015Q2	8065	8067.07	-2.07046	-0.03%	(0.03)
2015Q3	7934	7984.24	-50.2423	-0.63%	(0.84)
2015Q4	8159.67	8124.91	34.7602	0.43%	0.58
2016Q1	8285	8234.15	50.8458	0.61%	0.85
2016Q2	8149.33	8065.68	83.658	1.03%	1.40
2016Q3	7978.67	7972.88	5.78434	0.07%	0.10
2016Q4	8017.67	8086.07	-68.4001	-0.85%	(1.14)
2017Q1	8106.67	8102.91	3.75273	0.05%	0.06
2017Q2	7980	7998.37	-18.3728	-0.23%	(0.31)
2017Q3	7906	7910.96	-4.9584	-0.06%	(0.08)
2017Q4	8118.33	8094.06	24.2756	0.30%	0.40
2018Q1	8217	8210.45	6.55143	0.08%	0.11
2018Q2	8081.33	8166.95	-85.6175	-1.06%	(1.43)
2018Q3	8007.67	8111.17	-103.501	-1.29%	(1.73)
2018Q4	8274.67	8226.33	48.3351	0.58%	0.81
2019Q1	8340.33	8295.06	45.2752	0.54%	0.76
2019Q2	8233	8231.42	1.58496	0.02%	0.03
2019Q3	8094.67	8072.85	21.8198	0.27%	0.36
2019Q4	8259.33	8261.43	-2.09418	-0.03%	(0.03)
2020Q1	8334.33	8452.43	-118.099	-1.42%	(1.97)
2020Q2	8341	8330.92	10.0772	0.12%	0.17
2020Q3	8312	8299.05	12.9494	0.16%	0.22
2020Q4	8337	8367.91	-30.9128	-0.37%	(0.52)
2021Q1	8377.67	8327.04	50.6235	0.60%	0.84
2021Q2	8325.33	8219.97	105.36	1.27%	1.76
2021Q3	8186.67	8225.11	-38.4473	-0.47%	(0.64)
2021Q4	8221.67	8170.72	50.9502	0.62%	0.85
2022Q1	8301.33	8313.71	-12.3772	-0.15%	(0.21)
2022Q2	8116.33	8116.33	-1.5E-09	0.00%	0.00
2022Q3	7945.33	7945.33	-1.7E-09	0.00%	0.00

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	8221.667	8151.306	70.36	0.9%
Q1 2022	8301.333	8272.864	28.47	0.3%
Q2 2022	8116.333	8351.345	-235.01	-2.9%
Q3 2022	7945.333	8286.891	-341.56	-4.3%
Total	32584.67	33062.41	-477.74	-1.5%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	7382.808	7435.452	-52.644	-1%
S_GMP(-1)	21.35116	19.80008	1.55108	7%
S_D2020+S_D21Q1	162.0298	169.0137	-6.9839	-4%
S_D22Q3	-344.1358	0	-344.1358	
S_D22Q2	-201.074	0	-201.074	
S_D17Q3	-140.239	-135.4765	-4.7625	3%
S_D19Q2	123.7813	135.7141	-11.9328	-10%
S_D17Q2	-201.1034	-198.9703	-2.1331	1%
S_D17Q1	-118.3896	-119.6161	1.2265	-1%
AR(2)	-0.756841	-0.780795	0.023954	-3%

HLFC Brockton S&T
D. High Load Factor Customers - Sales and Transportation
1. Brockton

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
B_HLF_CUST_S_T	6	0.849	8.188

ARIMA Model Parameters

B_HLF_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	4918.074	233.837	21.03	0.000
	B_HLFNGP_ST_ROLL12(-1)	-277.0401	30.307	-9.14	0.000
	B_D2017	300.933	37.123	8.11	0.000
	B_D2019	-111.031	36.513	-3.04	0.005
	B_D16Q4	355.2657	69.292	5.13	0.000
	B_D18Q1	236.015	68.656	3.44	0.002

Variable	Definition	Explanation	Dummy Variable Support
B_HLFNGP_ST_ROLL12(-1)	Rolling 12 quarter natural gas price for high load factor sales and transport customers in Brockton ($2022/MMBtu) lagged one quarter		
B_D2017	Binary variable equal to 1 in 2017		2
B_D2019	Binary variable equal to 1 in 2019		2
B_D16Q4	Binary variable equal to 1 in 2016Q4		2
B_D18Q1	Binary variable equal to 1 in 2018Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
33	0.820704	30.29514

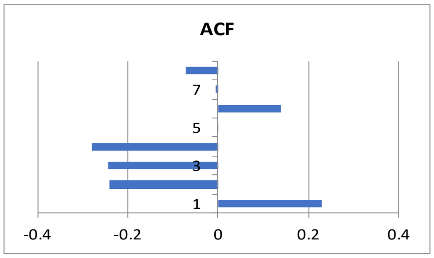
Chow Test Stats	N	k	SSR
Combined	33	6	121,346.03
1	17	5	72,906.99
2	16	3	24,657.40

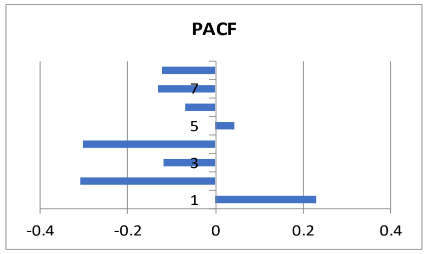
Chow Stat:	0.853
P-Value:	0.544265

Heteroscedasticity - White's Test	
White Stat	0.50
Significance (p-value)	0.77

Correlations

	B_HLFNGP_ST_ROLL12(-1)	B_D2017	B_D2019	B_D16Q4	B_D18Q1
B_HLFNGP_ST_ROLL12(-1)	1	0.205755	-0.143869	0.139752	0.057309
B_D2017	0.205755	1	-0.137931	-0.065653	-0.06565
B_D2019	-0.143869	-0.137931	1	-0.065653	-0.06565
B_D16Q4	0.139752	-0.065653	-0.065653	1	-0.03125
B_D18Q1	0.057309	-0.065653	-0.065653	-0.03125	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_hlf_cust_s_t Model	ACF	0.229	-0.241	-0.244	-0.281	-0.002	0.138	-0.006	-0.071
	SE	0.348	0.348	0.348	0.348	0.348	0.348	0.348	0.348
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_hlf_cust_s_t Model		0.229	-0.31	-0.117	-0.303	0.045	-0.07	-0.13	-0.122
	SE	0.348	0.348	0.348	0.348	0.348	0.348	0.348	0.348

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2014Q3	2711.67	2608.28	103.387	3.81%	1.54
2014Q4	2653	2617.17	35.8278	1.35%	0.53
2015Q1	2654	2625.15	28.849	1.09%	0.43
2015Q2	2626	2630.94	-4.94111	-0.19%	(0.07)
2015Q3	2576	2637.42	-61.4238	-2.38%	(0.92)
2015Q4	2559.33	2644.52	-85.1827	-3.33%	(1.27)
2016Q1	2594.33	2652.69	-58.3554	-2.25%	(0.87)
2016Q2	2573.33	2661.44	-88.1099	-3.42%	(1.31)
2016Q3	2709.33	2674.46	34.8692	1.29%	0.52
2016Q4	3043	3043	1.3E-12	0.00%	(0.00)
2017Q1	3066	3000.52	65.4753	2.14%	0.98
2017Q2	3049.33	3010.78	38.5582	1.26%	0.58
2017Q3	2985.67	3019.64	-33.9738	-1.14%	(0.51)
2017Q4	2959	3029.06	-70.0598	-2.37%	(1.05)
2018Q1	2975.67	2975.67	1.1E-12	0.00%	(0.00)
2018Q2	2936.67	2754.53	182.138	6.20%	2.72
2018Q3	2827.33	2770.04	57.2904	2.03%	0.85
2018Q4	2671	2785.92	-114.917	-4.30%	(1.71)
2019Q1	2672	2689.29	-17.2924	-0.65%	(0.26)
2019Q2	2636.33	2703.06	-66.728	-2.53%	(1.00)
2019Q3	2681	2714.12	-33.1152	-1.24%	(0.49)
2019Q4	2842	2724.86	117.136	4.12%	1.75
2020Q1	2849	2848.58	0.41617	0.01%	0.01
2020Q2	2847.67	2862.02	-14.3536	-0.50%	(0.21)
2020Q3	2857	2874.49	-17.4871	-0.61%	(0.26)
2020Q4	2884	2887.04	-3.037	-0.11%	(0.05)
2021Q1	2891	2898.01	-7.00779	-0.24%	(0.10)
2021Q2	2878.33	2907.12	-28.7891	-1.00%	(0.43)
2021Q3	2899	2916.51	-17.5141	-0.60%	(0.26)
2021Q4	2954.67	2926.13	28.5393	0.97%	0.43
2022Q1	2970.67	2937.46	33.2084	1.12%	0.50
2022Q2	2964.33	2951.78	12.5521	0.42%	0.19
2022Q3	2952.67	2968.63	-15.9587	-0.54%	(0.24)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	2954.667	2915.773	38.89	1.3%
Q1 2022	2970.667	2926.635	44.03	1.5%
Q2 2022	2964.333	2940.364	23.97	0.8%
Q3 2022	2952.667	2956.511	-3.84	-0.1%
Total	11842.33	11739.28	103.05	0.9%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	4918.074	4825.19	92.884	2%
B_HLFNGP_ST_ROLL12(-1)	-277.0401	-265.5619	-11.4782	4%
B_D2017	300.933	302.501	-1.568	-1%
B_D2019	-111.031	-105.1211	-5.9099	5%
B_D16Q4	355.2657	355.7427	-0.477	0%
B_D18Q1	236.015	238.643	-2.628	-1%

HLFC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
L_HLF_CUST_S_T	12	0.912	3.246

ARIMA Model Parameters

L_HLF_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	789.1263	12.471	63.28	0.000
	L_HLFNGP_ST_ROLL12(-3)	-5.396111	2.450	-2.20	0.033
	L_D09Q2_D12Q3	-45.44303	6.953	-6.54	0.000
	L_AFT_D19Q1	-35.44037	7.644	-4.64	0.000
	L_D18Q4	-108.2862	11.234	-9.64	0.000
	L_D18Q3	-60.81407	10.462	-5.81	0.000
	L_D14Q4_D16Q3*L_HLFNGP_ST_ROLL12	-15.57978	1.746	-8.92	0.000
	L_D14Q3	48.30162	11.861	4.07	0.000
	L_D16Q3+L_D16Q4	22.47353	9.859	2.28	0.027
	L_D17Q1	19.15565	10.176	1.88	0.066
	L_D14Q4	21.77183	10.813	2.01	0.050
	AR(1)	0.580657	0.135	4.30	0.000

Variable	Definition	Explanation	Dummy Variable Support
L_HLFNGP_ST_ROLL12(-3)	Rolling 12-quarter natural gas price for high load factor		
L_D09Q2_D12Q3	Binary variable equal to 1 from 2009Q2 to 2012Q3		2
L_AFT_D19Q1	Binary variable equal to 1 from 2019Q1 on		1
L_D18Q4	Binary variable equal to 1 in 2018Q4		2
L_D18Q3	Binary variable equal to 1 in 2018Q3		2
L_D14Q4_D16Q3*L_HLFNGP_ST_ROLL12	Rolling 12-quarter natural gas price for high load factor sales and transport customers in Lawrence ($2022) from 2014Q4 to 2016Q3	B	
L_D14Q3	Binary variable equal to 1 in 2014Q3		2
L_D16Q3+L_D16Q4	Binary variable equal to 1 in 2016Q3 and 2016Q4		2
L_D17Q1	Binary variable equal to 1 in 2017Q1		2
L_D14Q4	Binary variable equal to 1 in 2014Q4		2
AR(1)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
59	0.891351	44.25726

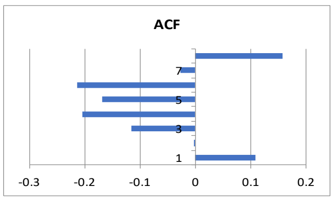
Chow Test Stats

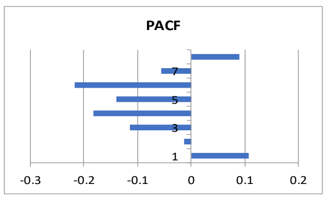
	N	k	SSR
Combined	59	12	5,216.42
1	30	7	2,732.67
2	29	9	1,317.93

Chow Stat:	0.839
P-Value:	0.611213

Heteroscedasticity - White's Test	
White Stat	0.87
Significance (p-value)	0.57

Correlations										
	L_HLFNGP_ST_ROLL12(-3)	L_D18Q4	L_D18Q3	L_D14Q3	L_D16Q3+L_D16Q4	L_D17Q1	L_D14Q4	L_D09Q2_D12Q3	L_AFT_D19Q1	L_D14Q3_D16Q3*L_HLFNGP_ST_ROLL12
L_HLFNGP_ST_ROLL12(-3)	1	-0.012134	-0.007739	0.036405	0.023789	0.01153	0.033675	0.31719	-0.191573	0.086678
L_D18Q4	-0.012134	1	-0.017241	-0.017241	-0.024596	-0.017241	-0.01724	-0.073239	-0.076666	-0.055706
L_D18Q3	-0.007739	-0.017241	1	-0.017241	-0.024596	-0.017241	-0.01724	-0.073239	-0.076666	-0.055706
L_D14Q3	0.036405	-0.017241	-0.017241	1	-0.024596	-0.017241	-0.01724	-0.073239	-0.076666	0.314427
L_D16Q3+L_D16Q4	0.023789	-0.024596	-0.024596	-0.024596	1	-0.024596	-0.0246	-0.104481	-0.10937	0.176443
L_D17Q1	0.01153	-0.017241	-0.017241	-0.017241	-0.024596	1	-0.01724	-0.073239	-0.076666	-0.055706
L_D14Q4	0.033675	-0.017241	-0.017241	-0.017241	-0.024596	-0.017241	1	-0.073239	-0.076666	0.31314
L_D09Q2_D12Q3	0.31719	-0.073239	-0.073239	-0.073239	-0.104481	-0.073239	-0.07324	1	-0.325669	-0.23663
L_AFT_D19Q1	-0.191573	-0.076666	-0.076666	-0.076666	-0.10937	-0.076666	-0.07667	-0.325669	1	-0.247703
L_D14Q3_D16Q3*L_HLFNGP_ST_ROLL12	0.086678	-0.055706	-0.055706	0.314427	0.176443	-0.055706	0.31314	-0.23663	-0.247703	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_hlf_cust_s_t Model	ACF	0.108	-0.001	-0.115	-0.204	-0.169	-0.213	-0.027	0.158
	SE	0.260	0.260	0.260	0.260	0.260	0.260	0.260	0.260
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_hlf_cust_s_t Model		0.108	-0.013	-0.115	-0.183	-0.139	-0.218	-0.056	0.09
	SE	0.260	0.260	0.260	0.260	0.260	0.260	0.260	0.260

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2008Q1	794	784.988	9.01164	1.13%	0.86
2008Q2	782	791.956	-9.95625	-1.27%	(0.95)
2008Q3	759.333	756.741	2.592	0.34%	0.25
2008Q4	739.667	760.201	-20.534	-2.78%	(1.95)
2009Q1	732.333	748.888	-16.5547	-2.26%	(1.57)
2009Q2	718	699.277	18.723	2.61%	1.78
2009Q3	709	717.365	-8.3652	-1.18%	(0.79)
2009Q4	724	712.173	11.8268	1.63%	1.12
2010Q1	721	720.916	0.08382	0.01%	0.01
2010Q2	715.667	719.217	-3.55058	-0.50%	(0.34)
2010Q3	711.667	716.197	-4.53033	-0.64%	(0.43)
2010Q4	718	713.913	4.0865	0.57%	0.39
2011Q1	721	717.623	3.37703	0.47%	0.32
2011Q2	709.333	719.397	-10.0637	-1.42%	(0.96)
2011Q3	703.667	712.641	-8.97405	-1.28%	(0.85)
2011Q4	706.667	709.378	-2.71114	-0.38%	(0.26)
2012Q1	708.667	711.14	-2.47322	-0.35%	(0.23)
2012Q2	692.667	712.307	-19.6402	-2.84%	(1.86)
2012Q3	717.667	703.092	14.575	2.03%	1.38
2012Q4	776.333	763.125	13.2079	1.70%	1.25
2013Q1	781.333	770.86	10.4732	1.34%	0.99
2013Q2	773	773.808	-0.80773	-0.10%	(0.08)
2013Q3	760.333	768.999	-8.66545	-1.14%	(0.82)
2013Q4	747.333	761.684	-14.3509	-1.92%	(1.36)
2014Q1	757.333	754.163	3.17024	0.42%	0.30
2014Q2	752.333	760.015	-7.68212	-1.02%	(0.73)
2014Q3	738.333	732.884	5.44968	0.74%	0.52
2014Q4	722	712.614	9.38559	1.30%	0.89
2015Q1	713	696.836	16.1641	2.27%	1.53
2015Q2	706.667	704.392	2.27482	0.32%	0.22
2015Q3	690.667	700.851	-10.1845	-1.47%	(0.97)
2015Q4	679	691.7	-12.6999	-1.87%	(1.21)
2016Q1	685	685.086	-0.08605	-0.01%	(0.01)
2016Q2	678.333	688.858	-10.5245	-1.55%	(1.00)
2016Q3	710	707.684	2.3155	0.33%	0.22
2016Q4	790.667	783.17	7.49626	0.95%	0.71
2017Q1	795.333	785.931	9.40184	1.18%	0.89
2017Q2	787.667	771.475	16.1921	2.06%	1.54
2017Q3	778.667	778.191	0.47572	0.06%	0.05
2017Q4	781.333	773.002	8.33126	1.07%	0.79
2018Q1	780.667	774.582	6.08476	0.78%	0.58
2018Q2	771.333	774.242	-2.90845	-0.38%	(0.28)
2018Q3	707.667	708.074	-0.40747	-0.06%	(0.04)
2018Q4	658.333	659.035	-0.70175	-0.11%	(0.07)
2019Q1	729.667	730.875	-1.20857	-0.17%	(0.11)
2019Q2	718.667	730.072	-11.4052	-1.59%	(1.08)
2019Q3	711	723.742	-12.7416	-1.79%	(1.21)
2019Q4	728.667	719.349	9.3177	1.28%	0.88
2020Q1	725.333	729.641	-4.30737	-0.59%	(0.41)
2020Q2	725.333	727.752	-2.41875	-0.33%	(0.23)
2020Q3	728	727.823	0.17723	0.02%	0.02
2020Q4	745.667	729.437	16.2292	2.18%	1.54
2021Q1	743.667	739.747	3.91965	0.53%	0.37
2021Q2	739.667	738.643	1.02317	0.14%	0.10
2021Q3	738.667	736.361	2.30614	0.31%	0.22
2021Q4	742	735.81	6.18954	0.83%	0.59
2022Q1	746	737.791	8.20946	1.10%	0.78
2022Q2	740.667	740.159	0.5078	0.07%	0.05
2022Q3	723	737.125	-14.125	-1.95%	(1.34)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	742	734.364	7.64	1.0%
Q1 2022	746	733.2964	12.70	1.7%
Q2 2022	740.6667	732.725	7.94	1.1%
Q3 2022	723	732.458	-9.46	-1.3%
Total	2951.67	2932.84	18.82	0.6%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	789.1263	789.2335	-0.1072	0%
L_HLFNGP_ST_ROLL12(-3)	-5.396111	-5.417102	0.020991	0%
L_D18Q4	-108.2862	-108.3645	0.0783	0%
L_D18Q3	-60.81407	-60.8438	0.02973	0%
L_D14Q3	48.30162	48.31486	-0.01324	0%
L_D16Q3+L_D16Q4	22.47353	22.47537	-0.00184	0%
L_D17Q1	19.15565	19.17688	-0.02123	0%
L_D14Q4	21.77183	21.79456	-0.02273	0%
L_D09Q2_D12Q3	-45.44303	-45.48648	0.04345	0%
L_AFT_D19Q1	-35.44037	-35.59183	0.15146	0%
L_D14Q3_D16Q3*L_HLFNGP_ST_ROLL12	-15.57978	-15.58235	0.00257	0%
AR(1)	0.580657	0.578401	0.002256	0%

HLFC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
S_HLF_CUST_S_T	7	0.915	5.278

ARIMA Model Parameters

S_HLF_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	1891.566	31.546	59.96	0.000
	S_HLFNGP_ST_ROLL12(-4)	-12.68627	5.100	-2.49	0.016
	S_D14Q4_D16Q3	-140.5639	21.570	-6.52	0.000
	S_D12Q4	86.77251	25.612	3.39	0.001
	S_AFT_D18Q3	-70.71645	23.655	-2.99	0.004
	S_D13Q1	50.3926	25.582	1.97	0.054
	AR(1)	0.75125	0.096	7.83	0.000

Variable	Definition	Explanation	Dummy Variable Support
S_HLFNGP_ST_ROLL12(-4)	Rolling 12-quarter natural gas price for high load factor sales and transport customers in Springfield ($2022) lagged four quarters		
S_D14Q4_D16Q3	Binary variable equal to 1 from 2014Q4 to 2016Q3		2
S_D12Q4	Binary variable equal to 1 in 2012Q4		2
S_AFT_D18Q3	Binary variable equal to 1 from 2018Q3 on		1
S_D13Q1	Binary variable equal to 1 in 2013Q1		2
AR(1)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

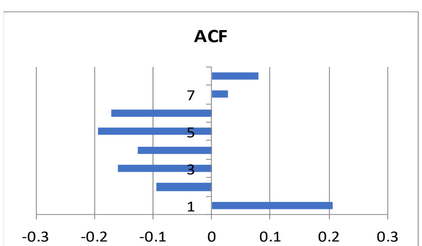
N	Adjusted R2	F Statistic
62	0.905815	98.77673

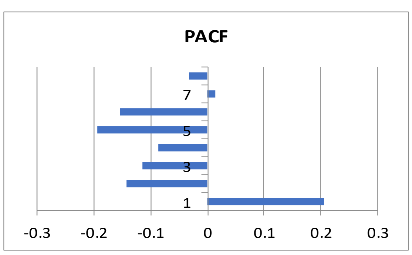
Chow Test Stats	N	k	SSR
Combined	62	7	42,677.28
1	32	6	22,222.41
2	30	5	16,179.00

Chow Stat:	0.764
P-Value:	0.620348

Heteroscedasticity - White's Test	
White Stat	0.89
Significance (p-value)	0.51

Correlations	S_HLFNGP_ST_ROLL12(-4)	S_D14Q4_D16Q3	S_D12Q4	S_AFT_D18Q3	S_D13Q1
S_HLFNGP_ST_ROLL12(-4)	1	0.112983	0.060731	0.034938	0.058764
S_D14Q4_D16Q3	0.112983	1	-0.049281	-0.236574	-0.04928
S_D12Q4	0.060731	-0.049281	1	-0.078696	-0.01639
S_AFT_D18Q3	0.034938	-0.236574	-0.078696	1	-0.0787
S_D13Q1	0.058764	-0.049281	-0.016393	-0.078696	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_hlf_cust_s_t Model	ACF	0.206	-0.094	-0.159	-0.127	-0.194	-0.171	0.027	0.08
	SE	0.254	0.254	0.254	0.254	0.254	0.254	0.254	0.254
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_hlf_cust_s_t Model		0.206	-0.142	-0.115	-0.086	-0.194	-0.154	0.015	-0.033
	SE	0.254	0.254	0.254	0.254	0.254	0.254	0.254	0.254

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2007Q2	1953.33	1957	-3.66711	-0.19%	(0.13)
2007Q3	1951.33	1937.97	13.3646	0.68%	0.48
2007Q4	1994	1936.47	57.5337	2.89%	2.07
2008Q1	1988.67	1968.52	20.1471	1.01%	0.72
2008Q2	1962	1964.51	-2.51295	-0.13%	(0.09)
2008Q3	1928.33	1944.48	-16.1463	-0.84%	(0.58)
2008Q4	1861.33	1844.12	17.2168	0.92%	0.62
2009Q1	1851.67	1850.92	0.74593	0.04%	0.03
2009Q2	1815.33	1843.92	-28.5819	-1.57%	(1.03)
2009Q3	1803	1816.8	-13.8044	-0.77%	(0.50)
2009Q4	1837	1807.55	29.4548	1.60%	1.06
2010Q1	1846.67	1833.17	13.4998	0.73%	0.48
2010Q2	1829.33	1840.52	-11.1838	-0.61%	(0.40)
2010Q3	1825.33	1827.59	-2.25698	-0.12%	(0.08)
2010Q4	1870.33	1824.76	45.5773	2.44%	1.64
2011Q1	1880	1858.61	21.3902	1.14%	0.77
2011Q2	1850	1865.89	-15.8904	-0.86%	(0.57)
2011Q3	1812.33	1843.4	-31.0702	-1.71%	(1.12)
2011Q4	1786	1815.11	-29.1089	-1.63%	(1.04)
2012Q1	1781.33	1795.34	-14.0057	-0.79%	(0.50)
2012Q2	1765	1791.83	-26.8272	-1.52%	(0.96)
2012Q3	1814.33	1779.54	34.7983	1.92%	1.25
2012Q4	1931.33	1903.53	27.7993	1.44%	1.00
2013Q1	1927	1890	37.0039	1.92%	1.33
2013Q2	1913	1863.74	49.2562	2.57%	1.77
2013Q3	1886	1891.15	-5.14522	-0.27%	(0.18)
2013Q4	1838	1870.93	-32.9252	-1.79%	(1.18)
2014Q1	1830.67	1834.98	-4.31518	-0.24%	(0.15)
2014Q2	1814.33	1829.57	-15.2325	-0.84%	(0.55)
2014Q3	1761	1817.4	-56.3968	-3.20%	(2.02)
2014Q4	1676.67	1636.84	39.8276	2.38%	1.43
2015Q1	1681.33	1679.16	2.17442	0.13%	0.08
2015Q2	1662	1682.72	-20.723	-1.25%	(0.74)
2015Q3	1648	1668.29	-20.2854	-1.23%	(0.73)
2015Q4	1643	1657.82	-14.8214	-0.90%	(0.53)
2016Q1	1633.67	1654.08	-20.4165	-1.25%	(0.73)
2016Q2	1622.67	1647.18	-24.5133	-1.51%	(0.88)
2016Q3	1697	1639	58.001	3.42%	2.08
2016Q4	1875	1835.42	39.5771	2.11%	1.42
2017Q1	1885	1863.54	21.4643	1.14%	0.77
2017Q2	1874	1871.13	2.86896	0.15%	0.10
2017Q3	1846.33	1862.9	-16.5673	-0.90%	(0.59)
2017Q4	1819.67	1842.14	-22.4755	-1.24%	(0.81)
2018Q1	1831	1822.11	8.88571	0.49%	0.32
2018Q2	1813.67	1830.63	-16.9607	-0.94%	(0.61)
2018Q3	1771.67	1746.92	24.7516	1.40%	0.89
2018Q4	1710.67	1768.57	-57.9062	-3.39%	(2.08)
2019Q1	1711.33	1722.86	-11.5305	-0.67%	(0.41)
2019Q2	1703.67	1723.42	-19.7544	-1.16%	(0.71)
2019Q3	1717.67	1717.73	-0.06718	0.00%	(0.00)
2019Q4	1755.67	1728.35	27.3129	1.56%	0.98
2020Q1	1733.33	1757.03	-23.6932	-1.37%	(0.85)
2020Q2	1724	1740.34	-16.3364	-0.95%	(0.59)
2020Q3	1726.67	1733.43	-6.75908	-0.39%	(0.24)
2020Q4	1744	1735.55	8.45339	0.48%	0.30
2021Q1	1745.33	1748.67	-3.33912	-0.19%	(0.12)
2021Q2	1737	1749.72	-12.7231	-0.73%	(0.46)
2021Q3	1737.33	1743.58	-6.24849	-0.36%	(0.22)
2021Q4	1792.67	1743.9	48.768	2.72%	1.75
2022Q1	1797	1785.54	11.4625	0.64%	0.41
2022Q2	1784	1788.9	-4.89877	-0.27%	(0.18)
2022Q3	1747	1779.25	-32.2453	-1.85%	(1.16)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	1792.667	1746.811	45.86	2.6%
Q1 2022	1797	1750.243	46.76	2.6%
Q2 2022	1784	1753.01	30.99	1.7%
Q3 2022	1747	1755.264	-8.26	-0.5%
Total	7120.67	7005.33	115.34	1.6%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	1891.566	1884.482	7.084	0%
S_HLFNGP_ST_ROLL12(-4)	-12.68627	-11.96386	-0.72241	6%
S_D14Q4_D16Q3	-140.5639	-138.0474	-2.5165	2%
S_D12Q4	86.77251	86.35866	0.41385	0%
S_AFT_D18Q3	-70.71645	-68.6435	-2.07295	3%
S_D13Q1	50.3926	49.77138	0.62122	1%
AR(1)	0.75125	0.779818	-0.028568	-4%

RHUPC Brockton S&T

II. Sales and Transportation - Use Per Customer

A. Residential Heating Use Per Customer - Sales & Transportation

1. Brockton

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
B_RH_UPC_S_T	8	0.999	0.799

ARIMA Model Parameters

B_RH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	9.691119	2.365	4.10	0.000
	B_RHNGP_ROLL12(-2)	-0.251895	0.142	-1.77	0.086
	B_Q1_EDD	0.012895	0.000	147.99	0.000
	B_Q2_EDD	0.011	0.000	49.46	0.000
	B_Q4_EDD	0.010042	0.000	54.55	0.000
	B_D15Q4	-1.792863	0.692	-2.59	0.015
	B_D21Q1	2.323054	0.667	3.48	0.002
	B_D22Q2	-1.764565	0.666	-2.65	0.013

Variable	Definition	Explanation	Dummy Variable Support
B_RHNGP_ROLL12(-2)	Rolling 12 quarter natural gas price for residential		
B_Q1_EDD	Effective Degree Days in Brockton in Q1	A	
B_Q2_EDD	Effective Degree Days in Brockton in Q2	A	
B_Q4_EDD	Effective Degree Days in Brockton in Q4	A	
B_D15Q4	Binary variable equal to 1 in 2015Q4		2
B_D21Q1	Binary variable equal to 1 in 2021Q1		2
B_D22Q2	Binary variable equal to 1 in 2022Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)

B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed

C: To account for seasonality

1: Included to address a structural shift

2: Included to address an outlier

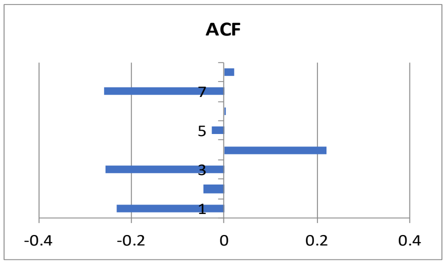
N	Adjusted R2	F Statistic
39	0.998409	3406.852

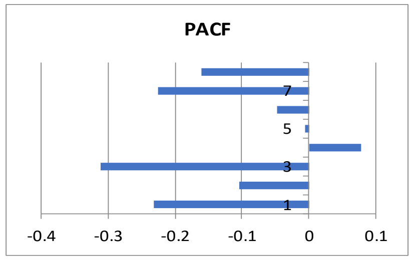
Chow Test Stats	N	k	SSR
Combined	39	8	12.64
1	17	6	5.29
2	22	7	3.42

Chow Stat:	1.297
P-Value:	0.293258

Heteroscedasticity - White's Test	
White Stat	1.81
Significance (p-value)	0.12

Correlations	B_RHNGP_ROLL12(-2)	B_Q1_EDD	B_Q2_EDD	B_Q4_EDD	B_D15Q4	B_D21Q1	B_D22Q2
B_RHNGP_ROLL12(-2)	1	0.015112	0.009836	-0.032245	0.229145	0.054886	0.037499
B_Q1_EDD	0.015112	1	-0.341231	-0.31679	-0.09451	0.236365	-0.09451
B_Q2_EDD	0.009836	-0.341231	1	-0.318468	-0.09501	-0.095012	0.233535
B_Q4_EDD	-0.032245	-0.31679	-0.318468	1	0.261777	-0.088207	-0.08821
B_D15Q4	0.229145	-0.094512	-0.095012	0.261777	1	-0.026316	-0.02632
B_D21Q1	0.054886	0.236365	-0.095012	-0.088207	-0.02632	1	-0.02632
B_D22Q2	0.037499	-0.094512	0.233535	-0.088207	-0.02632	-0.026316	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_rh_upc_s_t Model	ACF	-0.232	-0.044	-0.256	0.221	-0.025	0.002	-0.258	0.022
	SE	0.320	0.320	0.320	0.320	0.320	0.320	0.320	0.320
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_rh_upc_s_t Model		-0.232	-0.104	-0.311	0.078	-0.006	-0.047	-0.226	-0.16
	SE	0.320	0.320	0.320	0.320	0.320	0.320	0.320	0.320

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2013Q1	48.366	48.7071	-0.34102	-0.71%	(0.53)
2013Q2	19.1648	19.7911	-0.6263	-3.27%	(0.98)
2013Q3	6.02596	5.47134	0.55462	9.20%	0.87
2013Q4	23.9596	24.0543	-0.09475	-0.40%	(0.15)
2014Q1	54.77	54.2835	0.48645	0.89%	0.76
2014Q2	20.6882	20.3108	0.37739	1.82%	0.59
2014Q3	5.90868	5.43471	0.47397	8.02%	0.74
2014Q4	21.4447	22.7314	-1.28676	-6.00%	(2.01)
2015Q1	57.9003	56.6516	1.24869	2.16%	1.96
2015Q2	20.4577	20.1118	0.34592	1.69%	0.54
2015Q3	5.84385	5.23598	0.60787	10.40%	0.95
2015Q4	18.2769	18.2769	4E-15	0.00%	(0.00)
2016Q1	42.666	43.5112	-0.84523	-1.98%	(1.32)
2016Q2	19.3655	19.216	0.14946	0.77%	0.23
2016Q3	5.58925	5.33971	0.24954	4.46%	0.39
2016Q4	21.01	21.9352	-0.92516	-4.40%	(1.45)
2017Q1	45.2768	46.1474	-0.87055	-1.92%	(1.36)
2017Q2	21.0256	20.5978	0.42776	2.03%	0.67
2017Q3	5.83038	5.64734	0.18304	3.14%	0.29
2017Q4	20.8124	20.3534	0.45895	2.21%	0.72
2018Q1	49.5102	49.9183	-0.40801	-0.82%	(0.64)
2018Q2	21.2126	20.7176	0.49501	2.33%	0.78
2018Q3	5.26504	5.93375	-0.66871	-12.70%	(1.05)
2018Q4	25.0438	24.0408	1.00299	4.00%	1.57
2019Q1	48.8808	49.5071	-0.6264	-1.28%	(0.98)
2019Q2	19.1286	19.288	-0.15939	-0.83%	(0.25)
2019Q3	5.35863	5.64754	-0.28891	-5.39%	(0.45)
2019Q4	23.5803	23.0113	0.56906	2.41%	0.89
2020Q1	42.4258	42.1774	0.24841	0.59%	0.39
2020Q2	20.6406	20.8859	-0.24526	-1.19%	(0.38)
2020Q3	5.51094	5.48879	0.02215	0.40%	0.03
2020Q4	19.5775	19.2951	0.28237	1.44%	0.44
2021Q1	45.7995	45.7995	1.1E-14	0.00%	(0.00)
2021Q2	17.5017	18.4007	-0.89898	-5.14%	(1.41)
2021Q3	5.30413	5.48419	-0.18006	-3.39%	(0.28)
2021Q4	19.9407	19.9001	0.04063	0.20%	0.06
2022Q1	45.1202	44.3256	0.79455	1.76%	1.24
2022Q2	16.3237	16.3237	1.4E-14	0.00%	(0.00)
2022Q3	4.88198	5.43531	-0.55333	-11.33%	(0.87)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	19.94071	19.90262	0.04	0.2%
Q1 2022	45.12017	44.25178	0.87	1.9%
Q2 2022	16.32369	18.09679	-1.77	-10.9%
Q3 2022	4.881978	5.489258	-0.61	-12.4%
Total	86.27	87.74	-1.47	-1.7%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	9.691119	9.533495	0.157624	2%
B_RHNGP_ROLL12(-2)	-0.251895	-0.239372	-0.012523	5%
B_Q1_EDD	0.012895	0.012854	4.1E-05	0%
B_Q2_EDD	0.011	0.010962	3.8E-05	0%
B_Q4_EDD	0.010042	0.010011	3.1E-05	0%
B_D15Q4	-1.792863	-1.809407	0.016544	-1%
B_D21Q1	2.323054	2.390372	-0.067318	-3%
B_D22Q2	-1.764565	0	-1.764565	

RHUPC Lawrence S&T
2. Lawrence

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
L_RH_UPC_S_T	9	0.999	0.788

ARIMA Model Parameters

L_RH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	7.710904	0.291	26.46	0.000
	L_RHNGP_ROLL12(-3)	-0.065245	0.015	-4.41	0.000
	L_Q1_EDD	0.013409	0.000	213.99	0.000
	L_Q2_EDD	0.010675	0.000	66.02	0.000
	L_Q4_EDD	0.00981	0.000	78.03	0.000
	L_AFT_D15Q4*L_RHNGP_ROLL12(-4)	-0.053913	0.010	-5.24	0.000
	L_D12Q1	-1.484256	0.643	-2.31	0.025
	L_D12Q2	-1.626955	0.641	-2.54	0.014
	L_D17Q4	1.997303	0.645	3.10	0.003

Variable	Definition	Explanation	Dummy Variable Support
L_RHNGP_ROLL12(-3)	Rolling 12 quarter natural gas price for residential heating customers in Lawrence ($2022) lagged three quarters		
L_Q1_EDD	Effective Degree Days in Lawrence in Q1	A	
L_Q2_EDD	Effective Degree Days in Lawrence in Q2	A	
L_Q4_EDD	Effective Degree Days in Lawrence in Q4	A	
L_AFT_D15Q4*L_RHNGP_ROLL12(-4)	Rolling 12 quarter natural gas price for residential heating customers in Lawrence ($2022) lagged four quarters after 2015Q4	B	
L_D12Q1	Binary variable equal to 1 in 2012Q1		2
L_D12Q2	Binary variable equal to 1 in 2017Q4		2
L_D17Q4	Binary variable equal to 1 in 2012Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
63	0.998758	6231.25

Chow Test Stats

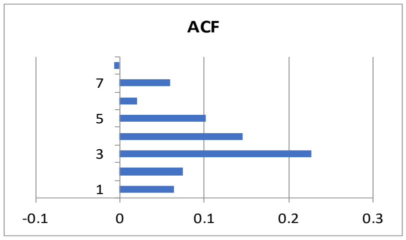
	N	k	SSR
Combined	63	9	20.85
1	32	7	8.66
2	31	7	9.93

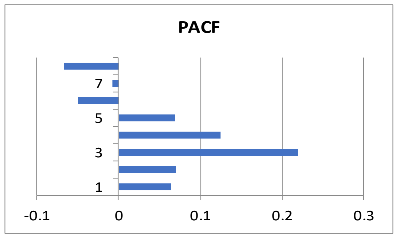
Chow Stat:	0.606
P-Value:	0.784963

Heteroscedasticity - White's Test	
White Stat	1.15
Significance (p-value)	0.34

Correlations

	L_RHNGP_ROLL12(-3)	L_Q1_EDD	L_Q2_EDD	L_Q4_EDD	L_AFT_D15Q4*L_RHNGP_ROLL12(-4)	L_D12Q1	L_D12Q2	L_D17Q4
L_RHNGP_ROLL12(-3)	1	-0.059347	-0.089634	0.052739	0.050761	0.05986	0.042585	-0.00341
L_Q1_EDD	-0.059347	1	-0.336325	-0.322755	-0.036206	0.184697	-0.07373	-0.07373
L_Q2_EDD	-0.089634	-0.336325	1	-0.322044	-0.012275	-0.073571	0.16511	-0.07357
L_Q4_EDD	0.052739	-0.322755	-0.322044	1	0.005619	-0.070602	-0.0706	0.192694
L_AFT_D15Q4*L_RHNGP_ROLL12(-4)	0.050761	-0.036206	-0.012275	0.005619	1	-0.11332	-0.11332	0.138314
L_D12Q1	0.05986	0.184697	-0.073571	-0.070602	-0.11332	1	-0.01613	-0.01613
L_D12Q2	0.042585	-0.073733	0.16511	-0.070602	-0.11332	-0.016129	1	-0.01613
L_D17Q4	-0.003413	-0.073733	-0.073571	0.192694	0.138314	-0.016129	-0.01613	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_rh_upc_s_t Model	ACF	0.064	0.075	0.227	0.146	0.102	0.021	0.06	-0.007
	SE	0.252	0.252	0.252	0.252	0.252	0.252	0.252	0.252
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_rh_upc_s_t Model		0.064	0.071	0.22	0.125	0.069	-0.05	-0.008	-0.067
	SE	0.252	0.252	0.252	0.252	0.252	0.252	0.252	0.252

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2007Q1	56.8388	56.5373	0.30147	0.53%	0.49
2007Q2	23.8759	23.5184	0.35747	1.50%	0.58
2007Q3	7.14218	7.7109	-0.56873	-7.96%	(0.92)
2007Q4	26.1933	25.7657	0.42758	1.63%	0.69
2008Q1	55.2904	54.6294	0.66096	1.20%	1.06
2008Q2	22.7999	23.1554	-0.35559	-1.56%	(0.57)
2008Q3	6.92603	6.30095	0.62508	9.03%	1.01
2008Q4	25.2739	24.9856	0.28831	1.14%	0.46
2009Q1	58.4146	57.3631	1.05152	1.80%	1.69
2009Q2	20.3264	20.4813	-0.1549	-0.76%	(0.25)
2009Q3	7.38942	6.30341	1.08601	14.70%	1.75
2009Q4	23.8691	23.9963	-0.12721	-0.53%	(0.20)
2010Q1	53.9854	53.9884	-0.00303	-0.01%	(0.00)
2010Q2	17.7773	17.7552	0.02212	0.12%	0.04
2010Q3	6.45199	6.43467	0.01733	0.27%	0.03
2010Q4	25.9528	25.212	0.74085	2.85%	1.19
2011Q1	57.0195	56.4632	0.55631	0.98%	0.90
2011Q2	21.8714	21.9283	-0.05689	-0.26%	(0.09)
2011Q3	6.6943	6.49996	0.19435	2.90%	0.31
2011Q4	21.2407	21.5089	-0.26826	-1.26%	(0.43)
2012Q1	47.0881	47.0881	-2.2E-15	0.00%	(0.00)
2012Q2	16.9122	16.9122	-2.9E-15	0.00%	(0.00)
2012Q3	6.34459	6.61264	-0.26805	-4.22%	(0.43)
2012Q4	23.5232	24.2942	-0.77097	-3.28%	(1.24)
2013Q1	52.8314	54.0653	-1.23386	-2.34%	(1.99)
2013Q2	21.0553	21.8435	-0.78823	-3.74%	(1.27)
2013Q3	6.60368	6.65454	-0.05087	-0.77%	(0.08)
2013Q4	25.7166	26.3993	-0.68277	-2.65%	(1.10)
2014Q1	59.8759	60.1618	-0.28586	-0.48%	(0.46)
2014Q2	23.0014	22.5757	0.42575	1.85%	0.69
2014Q3	6.58933	6.65452	-0.0652	-0.99%	(0.10)
2014Q4	24.2801	25.0069	-0.72673	-2.99%	(1.17)
2015Q1	62.3269	62.5249	-0.19808	-0.32%	(0.32)
2015Q2	22.1248	22.348	-0.22312	-1.01%	(0.36)
2015Q3	6.40995	6.6206	-0.21065	-3.29%	(0.34)
2015Q4	20.5793	21.776	-1.19668	-5.81%	(1.93)
2016Q1	46.8106	47.8829	-1.07233	-2.29%	(1.73)
2016Q2	20.5077	20.5202	-0.01257	-0.06%	(0.02)
2016Q3	6.15821	5.71024	0.44797	7.27%	0.72

2016Q4	23.588	23.3078	0.28015	1.19%	0.45
2017Q1	49.4066	50.3036	-0.89703	-1.82%	(1.44)
2017Q2	22.9074	21.8827	1.02475	4.47%	1.65
2017Q3	6.44194	5.85868	0.58326	9.05%	0.94
2017Q4	23.3596	23.3596	-7.8E-15	0.00%	(0.00)
2018Q1	54.6119	54.7547	-0.14282	-0.26%	(0.23)
2018Q2	21.8893	21.623	0.26629	1.22%	0.43
2018Q3	6.05889	6.00577	0.05312	0.88%	0.09
2018Q4	25.9039	25.7387	0.16521	0.64%	0.27
2019Q1	55.5183	54.1728	1.3455	2.42%	2.17
2019Q2	20.1345	20.6277	-0.49319	-2.45%	(0.79)
2019Q3	5.73788	5.949	-0.21112	-3.68%	(0.34)
2019Q4	25.6514	24.3786	1.27281	4.96%	2.05
2020Q1	46.0105	46.9443	-0.93376	-2.03%	(1.50)
2020Q2	21.2978	20.7355	0.56223	2.64%	0.90
2020Q3	5.69185	5.81746	-0.12561	-2.21%	(0.20)
2020Q4	21.5658	21.4902	0.07557	0.35%	0.12
2021Q1	49.6956	49.6402	0.05537	0.11%	0.09
2021Q2	18.1922	18.2429	-0.05073	-0.28%	(0.08)
2021Q3	5.61452	5.78641	-0.17189	-3.06%	(0.28)
2021Q4	20.8464	20.4333	0.41308	1.98%	0.66
2022Q1	49.9156	49.4333	0.48234	0.97%	0.78
2022Q2	17.5497	18.3165	-0.76678	-4.37%	(1.23)
2022Q3	5.13817	5.8074	-0.66924	-13.02%	(1.08)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	20.84636	20.43253	0.41	2.0%
Q1 2022	49.9156	49.42116	0.49	1.0%
Q2 2022	17.54974	18.37368	-0.82	-4.7%
Q3 2022	5.138167	5.862764	-0.72	-14.1%
Total	93.45	94.09	-0.64	-0.7%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	7.710904	7.744904	-0.034	0%
L_RHNGP_ROLL12(-3)	-0.065245	-0.065142	-0.000103	0%
L_Q1_EDD	0.013409	0.013388	2.1E-05	0%
L_Q2_EDD	0.010675	0.010676	-1E-06	0%
L_Q4_EDD	0.00981	0.009772	3.8E-05	0%
L_AFT_D15Q4*L_RHNGP_R(	-0.053913	-0.052669	-0.001244	2%
L_D12Q1	-1.484256	-1.454921	-0.029335	2%
L_D12Q2	-1.626955	-1.664609	0.037654	-2%
L_D17Q4	1.997303	2.002228	-0.004925	0%

RHUPC Springfield S&T
3. Springfield

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
S_RH_UPC_S_T	9	0.999	0.762

ARIMA Model Parameters

S_RH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	6.711338	0.211	31.76	0.000
	S_RHNGP_ROLL12(-4)	-0.05563	0.011	-5.10	0.000
	S_Q1_EDD+S_Q4_EDD	0.014474	0.000	121.87	0.000
	S_Q2_EDD	0.009851	0.000	57.63	0.000
	S_D07Q4	1.771278	0.627	2.83	0.007
	Q1+Q4	-8.517901	0.355	-23.98	0.000
	S_AFT_D20Q1*S_RHNGP_ROLL12	-0.091115	0.011	-7.95	0.000
	S_D19Q1	-1.705671	0.600	-2.84	0.006
	S_D17Q4	1.246959	0.604	2.06	0.043

Variable	Definition	Explanation	Dummy Variable Support
S_RHNGP_ROLL12(-4)	Rolling 12 quarter natural gas price for residential heating customers in Springfield ($2022) lagged four quarters		
S_Q1_EDD+S_Q4_EDD	Effective Degree Days in Springfield in Q1 and Q4	A	
S_Q2_EDD	Effective Degree Days in Springfield in Q2	A	
S_D07Q4	Binary variable equal to 1 in 2007Q4		2
Q1+Q4	Binary variable equal to 1 in Q1 and Q4	C	2
S_AFT_D20Q1*S_RHNGP_ROLL12	Rolling 12 quarter natural gas price for residential heating customers in Springfield ($2022) after 2020Q1	B	
S_D19Q1	Binary variable equal to 1 in 2019Q1		2
S_D17Q4	Binary variable equal to 1 in 2017Q4		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
67	0.998563	5733.343

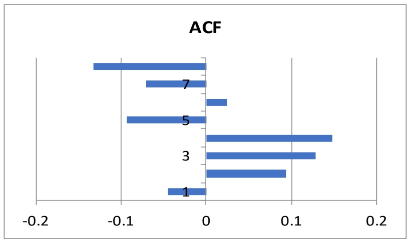
Chow Test Stats	N	k	SSR
Combined	67	9	19.51
1	32	6	7.89
2	35	8	9.80

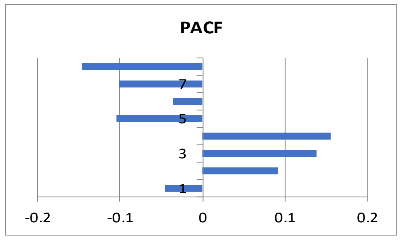
Chow Stat:	0.563
P-Value:	0.820212

Heteroscedasticity - White's Test	
White Stat	0.55
Significance (p-value)	0.81

Correlations

	S_RHNGP_ROLL12(-4)	S_Q1_EDD+S_Q4_EDD	S_Q2_EDD	S_D07Q4	Q1+Q4	S_AFT_D20Q1*S_RHNGP_ROLL12	S_D19Q1	S_D17Q4
S_RHNGP_ROLL12(-4)	1	0.027923	-0.035874	-0.266107	0.045475	0.125487	0.003094	0.023025
S_Q1_EDD+S_Q4_EDD	0.027923	1	-0.51022	0.030588	0.895921	-0.020285	0.193061	0.022292
S_Q2_EDD	-0.035874	-0.51022	1	-0.071154	-0.56949	0.043003	-0.07115	-0.07115
S_D07Q4	-0.266107	0.030588	-0.071154	1	0.124943	-0.054545	-0.01515	-0.01515
Q1+Q4	0.045475	0.895921	-0.569493	0.124943	1	-0.035331	0.124943	0.124943
S_AFT_D20Q1*S_RHNGP_ROLL12	0.125487	-0.020285	0.043003	-0.054545	-0.03533	1	-0.05455	-0.05455
S_D19Q1	0.003094	0.193061	-0.071154	-0.015152	0.124943	-0.054545	1	-0.01515
S_D17Q4	0.023025	0.022292	-0.071154	-0.015152	0.124943	-0.054545	-0.01515	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_rh_upc_s_t Model	ACF	-0.045	0.094	0.129	0.148	-0.093	0.025	-0.071	-0.132
	SE	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_rh_upc_s_t Model		-0.045	0.092	0.139	0.156	-0.105	-0.036	-0.102	-0.147
	SE	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2006Q1	46.8121	45.8773	0.93481	2.00%	1.61
2006Q2	16.9144	17.6297	-0.71531	-4.23%	(1.23)
2006Q3	6.41946	6.71134	-0.29187	-4.55%	(0.50)
2006Q4	19.9104	19.578	0.33247	1.67%	0.57
2007Q1	48.8895	48.4281	0.46136	0.94%	0.80
2007Q2	19.3274	18.7898	0.5376	2.78%	0.93
2007Q3	6.41127	6.71134	-0.30007	-4.68%	(0.52)
2007Q4	23.3301	23.3301			
2008Q1	47.187	46.4011	0.78589	1.67%	1.35
2008Q2	18.0217	18.1073	-0.08552	-0.47%	(0.15)
2008Q3	6.21832	6.71134	-0.49302	-7.93%	(0.85)
2008Q4	23.0923	22.4632	0.62902	2.72%	1.08
2009Q1	50.1107	49.8225	0.28824	0.58%	0.50
2009Q2	16.3741	16.6715	-0.29743	-1.82%	(0.51)
2009Q3	6.35447	5.43061	0.92386	14.54%	1.59
2009Q4	21.2598	21.0955	0.16427	0.77%	0.28
2010Q1	46.1169	46.1254	-0.00846	-0.02%	(0.01)
2010Q2	14.0634	13.6399	0.42349	3.01%	0.73
2010Q3	5.94956	5.56388	0.38568	6.48%	0.66
2010Q4	22.9545	22.514	0.44056	1.92%	0.76
2011Q1	49.35	49.7976	-0.44759	-0.91%	(0.77)
2011Q2	17.6923	17.2068	0.48544	2.74%	0.84
2011Q3	5.93194	5.64278	0.28916	4.87%	0.50
2011Q4	18.9421	18.1246	0.81747	4.32%	1.41
2012Q1	39.7251	39.1737	0.55144	1.39%	0.95
2012Q2	13.3029	14.0901	-0.78729	-5.92%	(1.36)
2012Q3	5.63796	5.7284	-0.09044	-1.60%	(0.16)
2012Q4	20.8986	20.8662	0.03241	0.16%	0.06
2013Q1	45.2703	46.2153	-0.94496	-2.09%	(1.63)
2013Q2	17.5942	17.5275	0.0668	0.38%	0.12
2013Q3	5.74818	5.7732	-0.02501	-0.44%	(0.04)
2013Q4	22.9593	23.7548	-0.79546	-3.46%	(1.37)
2014Q1	52.5078	53.0508	-0.54303	-1.03%	(0.94)
2014Q2	18.6324	17.6392	0.99321	5.33%	1.71
2014Q3	5.76524	5.77653	-0.0113	-0.20%	(0.02)
2014Q4	21.4016	20.9427	0.45884	2.14%	0.79
2015Q1	54.732	54.4491	0.28296	0.52%	0.49
2015Q2	18.0518	17.0988	0.95293	5.28%	1.64
2015Q3	5.6102	5.76151	-0.15132	-2.70%	(0.26)
2015Q4	17.5575	17.9978	-0.44024	-2.51%	(0.76)

2016Q1	40.7001	40.771	-0.07087	-0.17%	(0.12)
2016Q2	16.6624	17.1775	-0.5151	-3.09%	(0.89)
2016Q3	5.36427	5.74919	-0.38491	-7.18%	(0.66)
2016Q4	20.8879	21.4558	-0.56788	-2.72%	(0.98)
2017Q1	43.2401	43.39	-0.14984	-0.35%	(0.26)
2017Q2	17.6779	18.0661	-0.38819	-2.20%	(0.67)
2017Q3	5.491	5.81113	-0.32013	-5.83%	(0.55)
2017Q4	20.5195	20.5195	-1.8E-15	0.00%	(0.00)
2018Q1	47.3034	48.3972	-1.0938	-2.31%	(1.89)
2018Q2	18.4671	18.4902	-0.02318	-0.13%	(0.04)
2018Q3	5.07288	5.86966	-0.79678	-15.71%	(1.37)
2018Q4	24.5086	24.8794	-0.37079	-1.51%	(0.64)
2019Q1	46.2857	46.2857	1.1E-15	0.00%	(0.00)
2019Q2	16.7131	16.4507	0.26245	1.57%	0.45
2019Q3	5.1094	5.84556	-0.73616	-14.41%	(1.27)
2019Q4	22.8664	22.5	0.36645	1.60%	0.63
2020Q1	41.0181	40.2983	0.71977	1.75%	1.24
2020Q2	17.9557	17.7959	0.15978	0.89%	0.28
2020Q3	5.18593	4.2324	0.95353	18.39%	1.64
2020Q4	19.361	20.0715	-0.71056	-3.67%	(1.23)
2021Q1	44.5998	44.84	-0.24018	-0.54%	(0.41)
2021Q2	15.316	15.8716	-0.55562	-3.63%	(0.96)
2021Q3	4.89633	4.25817	0.63816	13.03%	1.10
2021Q4	18.7649	19.7371	-0.97224	-5.18%	(1.68)
2022Q1	44.7884	44.6985	0.08995	0.20%	0.16
2022Q2	15.3437	16.0007	-0.65696	-4.28%	(1.13)
2022Q3	4.73967	4.18614	0.55353	11.68%	0.95

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	18.76485	19.93671	-1.17	-6.2%
Q1 2022	44.78843	44.8193	-0.03	-0.1%
Q2 2022	15.34374	16.16921	-0.83	-5.4%
Q3 2022	4.73967	4.281946	0.46	9.7%
Total	83.64	85.21	-1.57	-1.9%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	6.711338	6.666727	0.044611	1%
S_RHNGP_ROLL12(-4)	-0.05563	-0.056062	0.000432	-1%
S_Q1_EDD+S_Q4_EDD	0.014474	0.014427	4.7E-05	0%
S_Q2_EDD	0.009851	0.009915	-6.4E-05	-1%
S_D07Q4	1.771278	1.702784	0.068494	4%
Q1+Q4	-8.517901	-8.330177	-0.187724	2%
S_AFT_D20Q1*S_RHNGP_ ROLL12	-0.091115	-0.082732	-0.008383	9%
S_D19Q1	-1.705671	-1.680631	-0.02504	1%
S_D17Q4	1.246959	1.180958	0.066001	5%

RNHUPC Brockton S&T
B. Residential Non-Heating User per Customer - Sales & Transportation
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
B_RNH_UPC_S_T	6	0.968	0.477

ARIMA Model Parameters

B_RNH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	4.545535	0.833	5.45	0.000
	B_RRNGP_ROLL12(-1)	-0.068251	0.034	-2.02	0.049
	B_Q1_EDD+B_Q2_EDD +B_Q4_EDD	0.000994	0.000	37.46	0.000
	B_D15Q4	-0.413278	0.230	-1.80	0.079
	B_D09Q3	0.609611	0.255	2.40	0.021
	B_D10Q2	0.477908	0.237	2.02	0.049

Variable	Definition	Explanation	Dummy Variable Support
B_RRNGP_ROLL12(-1)	Natural gas price for residential non heating customers in Brockton ($2022) lagged one quarter		
B_Q1_EDD+B_Q2_EDD+B_Q4_EDD	Effective Degree Days in Brockton in Q1, Q2 and Q4	A	
B_D15Q4	Binary variable equal to 1 in 2014Q2		2
B_D09Q3	Binary variable equal to 1 in 2016Q1		2
B_D10Q2	Binary variable equal to 1 in 2020Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
54	0.96429	287.234

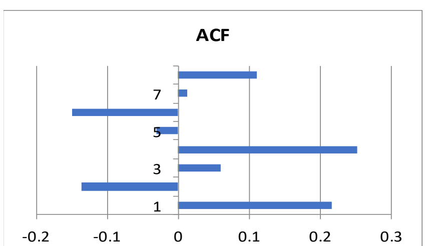
Chow Test Stats	N	k	SSR
Combined	54	6	2.49
1	25	5	0.94
2	29	4	1.14

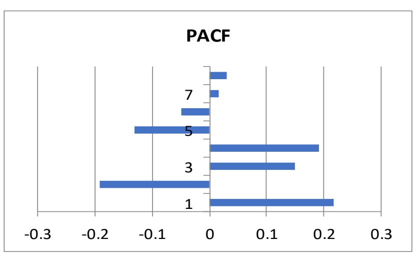
Chow Stat:	1.362
P-Value:	0.252359

Heteroscedasticity - White's Test	
White Stat	0.89
Significance (p-value)	0.49

Correlations

	B_RRNGP_ROLL12(-1)	B_Q1_EDD+B_Q2_EDD+B_Q4_EDD	B_D15Q4	B_D09Q3	B_D10Q2
B_RRNGP_ROLL12(-1)	1	-0.080799	-0.021301	0.390403	0.210399
B_Q1_EDD+B_Q2_EDD+B_Q4_EDD	-0.080799	1	-0.003244	-0.173811	-0.06531
B_D15Q4	-0.021301	-0.003244	1	-0.018868	-0.01887
B_D09Q3	0.390403	-0.173811	-0.018868	1	-0.01887
B_D10Q2	0.210399	-0.065306	-0.018868	-0.018868	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_rnh_upc_s_t Model	ACF	0.217	-0.136	0.06	0.252	-0.03	-0.149	0.013	0.11
	SE	0.272	0.272	0.272	0.272	0.272	0.272	0.272	0.272
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_rnh_upc_s_t Model		0.217	-0.191	0.149	0.191	-0.13	-0.05	0.016	0.031
	SE	0.272	0.272	0.272	0.272	0.272	0.272	0.272	0.272

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2009Q2	4.29302	3.86859	0.42444	9.89%	1.86
2009Q3	3.27233	3.27233			
2009Q4	4.26184	4.33561	-0.07378	-1.73%	(0.32)
2010Q1	5.99404	6.12636	-0.13232	-2.21%	(0.58)
2010Q2	4.16529	4.16529	-3.9E-16	0.00%	(0.00)
2010Q3	2.97719	2.77207	0.20512	6.89%	0.90
2010Q4	4.36849	4.52091	-0.15242	-3.49%	(0.67)
2011Q1	6.01463	6.32796	-0.31333	-5.21%	(1.38)
2011Q2	4.41937	4.10541	0.31396	7.10%	1.38
2011Q3	3.03535	2.81891	0.21644	7.13%	0.95
2011Q4	4.40213	4.27496	0.12717	2.89%	0.56
2012Q1	5.92629	5.80296	0.12333	2.08%	0.54
2012Q2	4.11646	3.91585	0.20062	4.87%	0.88
2012Q3	2.87042	2.92311	-0.05269	-1.84%	(0.23)
2012Q4	4.8483	4.56049	0.2878	5.94%	1.26
2013Q1	6.44089	6.26187	0.17902	2.78%	0.79
2013Q2	4.34174	4.24023	0.10151	2.34%	0.45
2013Q3	2.98559	2.94055	0.04504	1.51%	0.20
2013Q4	4.87438	4.79076	0.08363	1.72%	0.37
2014Q1	7.04769	6.73093	0.31676	4.49%	1.39
2014Q2	4.65297	4.31173	0.34124	7.33%	1.50
2014Q3	3.08194	2.94448	0.13745	4.46%	0.60
2014Q4	4.32643	4.65751	-0.33108	-7.65%	(1.45)
2015Q1	6.54996	6.87519	-0.32522	-4.97%	(1.43)
2015Q2	4.20143	4.23338	-0.03195	-0.76%	(0.14)
2015Q3	3.0583	2.87975	0.17856	5.84%	0.78
2015Q4	3.92567	3.92567	1.1E-16	0.00%	(0.00)
2016Q1	5.57592	5.80849	-0.23257	-4.17%	(1.02)
2016Q2	4.1625	4.11735	0.04515	1.08%	0.20
2016Q3	2.83745	2.8704	-0.03295	-1.16%	(0.14)
2016Q4	4.10485	4.49332	-0.38847	-9.46%	(1.71)
2017Q1	6.05207	5.98312	0.06895	1.14%	0.30
2017Q2	4.38676	4.21446	0.1723	3.93%	0.76
2017Q3	2.94982	2.89336	0.05647	1.91%	0.25
2017Q4	4.22984	4.33663	-0.10679	-2.52%	(0.47)
2018Q1	6.38418	6.3077	0.07648	1.20%	0.34
2018Q2	4.26734	4.25501	0.01233	0.29%	0.05
2018Q3	2.68811	2.90244	-0.21433	-7.97%	(0.94)
2018Q4	4.40242	4.69612	-0.2937	-6.67%	(1.29)
2019Q1	6.18491	6.25925	-0.07434	-1.20%	(0.33)
2019Q2	4.10835	4.09957	0.00879	0.21%	0.04
2019Q3	2.7714	2.85498	-0.08358	-3.02%	(0.37)
2019Q4	4.38767	4.58128	-0.19361	-4.41%	(0.85)
2020Q1	5.95567	5.68099	0.27468	4.61%	1.21
2020Q2	4.56746	4.24753	0.31994	7.00%	1.41
2020Q3	2.7314	2.85178	-0.12038	-4.41%	(0.53)
2020Q4	4.09206	4.22129	-0.12924	-3.16%	(0.57)
2021Q1	6.14884	5.78207	0.36677	5.96%	1.61
2021Q2	3.90095	4.03704	-0.13609	-3.49%	(0.60)
2021Q3	2.72112	2.88074	-0.15962	-5.87%	(0.70)
2021Q4	3.7923	4.29217	-0.49987	-13.18%	(2.20)
2022Q1	5.86581	5.84128	0.02453	0.42%	0.11
2022Q2	3.66059	3.98581	-0.32522	-8.88%	(1.43)
2022Q3	2.51682	2.82174	-0.30492	-12.12%	(1.34)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	3.792296	4.316618	-0.52	-13.8%
Q1 2022	5.865807	5.85138	0.01	0.2%
Q2 2022	3.660588	4.015781	-0.36	-9.7%
Q3 2022	2.516819	2.865916	-0.35	-13.9%
Total	15.84	17.05	-1.21	-7.7%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	4.545535	4.425128	0.120407	3%
B_RRNGP_ROLL12(-1)	-0.068251	-0.061735	-0.006516	10%
B_Q1_EDD+B_Q2_EDD+B_Q4_EDD	0.000994	0.000983	1.1E-05	1%
B_D15Q4	-0.413278	-0.437321	0.024043	-6%
B_D09Q3	0.609611	0.550253	0.059358	10%
B_D10Q2	0.477908	0.437038	0.04087	9%

RNHUPC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
L_RNH_UPC_S_T	10	0.983	0.476

ARIMA Model Parameters

L_RNH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	3.395545	0.074	45.67	0.000
	L_RRNGP(-4)*L_D16Q1_AFT	-0.015045	0.003	-4.79	0.000
	L_Q1_EDD+L_Q2_EDD+L_Q4_EDD	0.001136	0.000	38.15	0.000
	L_D13Q1	1.157463	0.242	4.78	0.000
	L_D19Q1	0.891596	0.241	3.71	0.001
	L_D22Q1	0.79083	0.238	3.32	0.002
	L_D18Q4	-0.618669	0.233	-2.66	0.012
	Q2	0.397252	0.078	5.10	0.000
	L_D15Q1	-0.82903	0.247	-3.35	0.002
	L_D15Q4	-0.591966	0.234	-2.53	0.016

Variable	Definition	Explanation	Dummy Variable Support
L_RRNGP(-4)*L_D16Q1_AFT	Natural gas price for residential non heating customers in Lawrence ($2022) lagged four quarters from 2016Q1 on	B	
L_Q1_EDD+L_Q2_EDD+L_Q4_EDD	Effective Degree Days in Lawrence in Q1, Q2 and Q4	A	
L_D13Q1	Binary variable equal to 1 in 2013Q1		2
L_D19Q1	Binary variable equal to 1 in 2019Q1		2
L_D22Q1	Binary variable equal to 1 in 2022Q1		2
L_D18Q4	Binary variable equal to 1 in 2018Q4		2
Q2	Binary variable equal to 1 in Q2	C	2
L_D15Q1	Binary variable equal to 1 in 2015Q1		2
L_D15Q4	Binary variable equal to 1 in 2015Q4		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
47	0.978732	236.2098

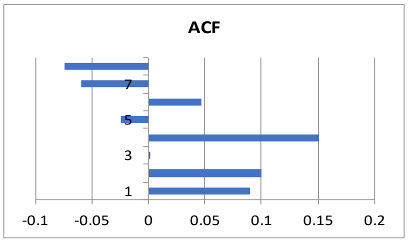
Chow Test Stats	N	k	SSR
Combined	47	10	1.90
1	28	7	0.80
2	19	7	0.57

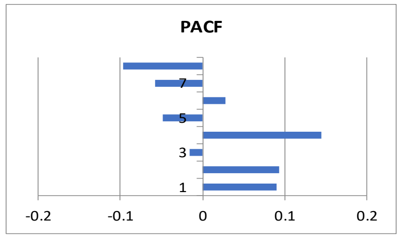
Chow Stat:	1.034
P-Value:	0.442853

Heteroscedasticity - White's Test	
White Stat	0.90
Significance (p-value)	0.53

Correlations

	L_RRNGP(-4)*L_D16Q1_AFT	L_Q1_EDD+L_Q2_EDD+L_Q4_EDD	L_D13Q1	L_D19Q1	L_D22Q1	L_D18Q4	Q2	L_D15Q1	L_D15Q4
L_RRNGP(-4)*L_D16Q1_AFT	1	-0.046852	-0.171008	0.122764	0.116443	0.115857	0.009108	-0.17101	-0.17101
L_Q1_EDD+L_Q2_EDD+L_Q4_EDD	-0.046852	1	0.21869	0.22531	0.185856	0.041948	-0.12882	0.29196	-0.00119
L_D13Q1	-0.171008	0.21869	1	-0.021739	-0.02174	-0.021739	-0.08633	-0.02174	-0.02174
L_D19Q1	0.122764	0.22531	-0.021739	1	-0.02174	-0.021739	-0.08633	-0.02174	-0.02174
L_D22Q1	0.116443	0.185856	-0.021739	-0.021739	1	-0.021739	-0.08633	-0.02174	-0.02174
L_D18Q4	0.115857	0.041948	-0.021739	-0.021739	-0.02174	1	-0.08633	-0.02174	-0.02174
Q2	0.009108	-0.12882	-0.086333	-0.086333	-0.08633	-0.086333	1	-0.08633	-0.08633
L_D15Q1	-0.171008	0.29196	-0.021739	-0.021739	-0.02174	-0.021739	-0.08633	1	-0.02174
L_D15Q4	-0.171008	-0.001186	-0.021739	-0.021739	-0.02174	-0.021739	-0.08633	-0.02174	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_rnh_upc_s_t Model	ACF	0.09	0.1	0.001	0.151	-0.024	0.047	-0.059	-0.074
	SE	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_rnh_upc_s_t Model		0.09	0.093	-0.016	0.145	-0.049	0.028	-0.058	-0.097
	SE	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2011Q1	7.37881	7.62837	-0.24956	-3.38%	(1.10)
2011Q2	5.42764	5.43506	-0.00742	-0.14%	(0.03)
2011Q3	3.46558	3.39555	0.07003	2.02%	0.31
2011Q4	5.3819	5.1313	0.2506	4.66%	1.11
2012Q1	6.84435	6.95486	-0.11051	-1.61%	(0.49)
2012Q2	5.0173	5.06397	-0.04667	-0.93%	(0.21)
2012Q3	3.13178	3.39555	-0.26377	-8.42%	(1.16)
2012Q4	5.56346	5.4394	0.12406	2.23%	0.55
2013Q1	8.56798	8.56798	-4.4E-16	0.00%	(0.00)
2013Q2	5.78825	5.409	0.37926	6.55%	1.67
2013Q3	3.43459	3.39555	0.03904	1.14%	0.17
2013Q4	5.92071	5.67974	0.24096	4.07%	1.06
2014Q1	7.85335	7.92642	-0.07307	-0.93%	(0.32)
2014Q2	5.54779	5.48697	0.06082	1.10%	0.27
2014Q3	3.5963	3.39555	0.20075	5.58%	0.89
2014Q4	5.32391	5.51975	-0.19584	-3.68%	(0.86)
2015Q1	7.29967	7.29967	-4.4E-16	0.00%	(0.00)
2015Q2	5.21572	5.46491	-0.24918	-4.78%	(1.10)
2015Q3	3.25536	3.39555	-0.14019	-4.31%	(0.62)
2015Q4	4.66337	4.66337	-7.8E-16	0.00%	(0.00)
2016Q1	6.44699	6.5959	-0.14891	-2.31%	(0.66)
2016Q2	4.91111	5.01381	-0.10269	-2.09%	(0.45)
2016Q3	3.12583	3.04109	0.08475	2.71%	0.37
2016Q4	4.67808	5.08284	-0.40477	-8.65%	(1.79)
2017Q1	6.50443	6.83517	-0.33074	-5.08%	(1.46)
2017Q2	5.09454	5.17834	-0.0838	-1.64%	(0.37)
2017Q3	3.32153	3.06947	0.25205	7.59%	1.11
2017Q4	4.87029	4.85912	0.01117	0.23%	0.05
2018Q1	7.37394	7.19656	0.17738	2.41%	0.78
2018Q2	4.82347	5.1208	-0.29733	-6.16%	(1.31)
2018Q3	3.24316	3.06599	0.17717	5.46%	0.78
2018Q4	4.72958	4.72958	1E-15	0.00%	0.00
2019Q1	8.02919	8.02919			
2019Q2	5.23483	4.9946	0.24024	4.59%	1.06
2019Q3	3	3.03425	-0.03425	-1.14%	(0.15)
2019Q4	5.11139	5.17419	-0.0628	-1.23%	(0.28)
2020Q1	6.95721	6.51516	0.44205	6.35%	1.95
2020Q2	5.39462	5.02855	0.36606	6.79%	1.62
2020Q3	3.04728	3.04082	0.00646	0.21%	0.03
2020Q4	4.86296	4.85613	0.00682	0.14%	0.03
2021Q1	7.21292	6.76585	0.44707	6.20%	1.97
2021Q2	4.71962	4.78214	-0.06252	-1.32%	(0.28)
2021Q3	3.03725	3.06697	-0.02971	-0.98%	(0.13)
2021Q4	4.57778	4.75994	-0.18216	-3.98%	(0.80)
2022Q1	7.54897	7.54897	4.4E-16	0.00%	0.00
2022Q2	4.58892	4.78568	-0.19676	-4.29%	(0.87)
2022Q3	2.74837	3.05246	-0.30409	-11.06%	(1.34)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	4.577778	4.790865	-0.21	-4.7%
Q1 2022	7.548975	6.772424	0.78	10.3%
Q2 2022	4.588921	4.819112	-0.23	-5.0%
Q3 2022	2.748372	3.098746	-0.35	-12.7%
Total	19.46	19.48	-0.02	-0.1%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	3.395545	3.410663	-0.015118	0%
L_RRNGP(-4)*L_D16Q1_AFT	-0.015045	-0.013679	-0.001366	9%
L_Q1_EDD+L_Q2_EDD+L_Q4_	0.001136	0.001126	0.00001	1%
L_D13Q1	1.157463	1.175897	-0.018434	-2%
L_D19Q1	0.891596	0.879889	0.011707	1%
L_D22Q1	0.79083	0	0.79083	100%
L_D18Q4	-0.618669	-0.644674	0.026005	-4%
Q2	0.397252	0.396198	0.001054	0%
L_D15Q1	-0.82903	-0.804594	-0.024436	3%
L_D15Q4	-0.591966	-0.591543	-0.000423	0%

RNHUPC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
S_RNH_UPC_S_T	8	0.989	0.404

ARIMA Model Parameters

S_RNH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	3.251974	0.092	35.41	0.000
	S_AFT_D21Q2*S_RRNGP_ROLL12	-0.024478	0.002	-11.23	0.000
	S_Q1_EDD+S_Q2_EDD+S_Q4_EDD	0.001047	0.000	18.21	0.000
	S_D12Q2_D14Q3	0.583441	0.053	11.01	0.000
	S_D18Q3_D20Q4	-0.210801	0.042	-5.00	0.000
	S_D13Q1	0.360716	0.164	2.21	0.034
	S_D14Q1	-0.871096	0.171	-5.10	0.000
	AR(2)	-0.692153	0.114	-6.05	0.000

Variable	Definition	Explanation	Dummy Variable Support
S_AFT_D21Q2*S_RRNGP_ROLL12	Natural gas price for residential non heating customers in Springfield ($2022) from 2021Q2 on	B	
S_Q1_EDD+S_Q2_EDD+S_Q4_EDD	Effective Degree Days in Springfield in Q1, Q2, and Q4	A	
S_D12Q2_D14Q3	Binary variable equal to 1 from 2012Q2 to 2014Q3		2
S_D18Q3_D20Q4	Binary variable equal to 1 from 2018Q3 to 2020Q4		2
S_D13Q1	Binary variable equal to 1 in 2013Q1		2
S_D14Q1	Binary variable equal to 1 in 2014Q1		2
AR(2)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
42	0.986591	431.9602

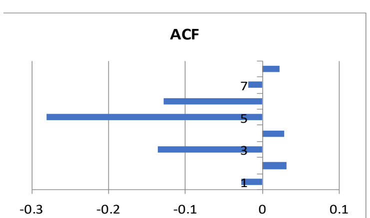
Chow Test Stats	N	k	SSR
Combined	42	8	0.90
1	25	6	0.59
2	17	5	0.26

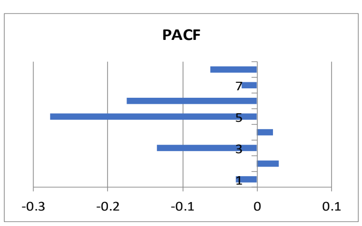
Chow Stat:	0.235
P-Value:	0.980493

Heteroscedasticity - White's Test	
White Stat	0.89
Significance (p-value)	0.53

Correlations

	S_AFT_D21Q2*S_RRNGP_ROLL12	S_Q1_EDD+S_Q2_EDD+S_Q4_EDD	S_D12Q2_D14Q3	S_D18Q3_D20Q4	S_D13Q1	S_D14Q1
S_AFT_D21Q2*S_RRNGP_ROLL12	1	-0.094756	-0.228187	-0.228187	-0.06375	-0.063749
S_Q1_EDD+S_Q2_EDD+S_Q4_EDD	-0.094756	1	-0.056905	-0.03876	0.234694	0.294035
S_D12Q2_D14Q3	-0.228187	-0.056905	1	-0.3125	0.279372	0.279372
S_D18Q3_D20Q4	-0.228187	-0.03876	-0.3125	1	-0.0873	-0.087304
S_D13Q1	-0.063749	0.234694	0.279372	-0.087304	1	-0.02439
S_D14Q1	-0.063749	0.294035	0.279372	-0.087304	-0.02439	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_rnh_upc_s_t	ACF	-0.028	0.031	-0.136	0.029	-0.28	-0.129	-0.018	0.023
	SE	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_rnh_upc_s_t		-0.028	0.03	-0.134	0.021	-0.277	-0.175	-0.021	-0.063
	SE	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2012Q2	4.69208	4.37503	0.31704	6.76%	1.94
2012Q3	3.35959	3.54594	-0.18634	-5.55%	(1.14)
2012Q4	5.50825	5.57051	-0.06226	-1.13%	(0.38)
2013Q1	8.15243	8.06777	0.08466	1.04%	0.52
2013Q2	5.32427	5.10986	0.21441	4.03%	1.31
2013Q3	3.42654	3.54886	-0.12232	-3.57%	(0.75)
2013Q4	5.62541	5.58598	0.03943	0.70%	0.24
2014Q1	7.34708	7.28258	0.0645	0.88%	0.40
2014Q2	5.01104	5.18318	-0.17215	-3.44%	(1.06)
2014Q3	3.5017	3.59489	-0.09319	-2.66%	(0.57)
2014Q4	4.97297	5.02332	-0.05035	-1.01%	(0.31)
2015Q1	7.59588	7.61967	-0.0238	-0.31%	(0.15)
2015Q2	4.79022	4.45103	0.33919	7.08%	2.08
2015Q3	3.29302	3.10857	0.18445	5.60%	1.13
2015Q4	4.50595	4.52293	-0.01699	-0.38%	(0.10)
2016Q1	6.21451	6.37347	-0.15896	-2.56%	(0.97)
2016Q2	4.59949	4.63802	-0.03853	-0.84%	(0.24)
2016Q3	3.14878	3.38166	-0.23288	-7.40%	(1.43)
2016Q4	4.63845	4.91174	-0.27329	-5.89%	(1.68)
2017Q1	6.62643	6.66092	-0.0345	-0.52%	(0.21)
2017Q2	4.89133	4.80889	0.08245	1.69%	0.51
2017Q3	3.16748	3.22641	-0.05893	-1.86%	(0.36)
2017Q4	4.73858	4.60943	0.12915	2.73%	0.79
2018Q1	6.97794	7.00612	-0.02818	-0.40%	(0.17)
2018Q2	4.68522	4.6651	0.02012	0.43%	0.12
2018Q3	3.05094	3.0202	0.03074	1.01%	0.19
2018Q4	4.98778	4.9686	0.01918	0.38%	0.12
2019Q1	6.74539	6.69707	0.04832	0.72%	0.30
2019Q2	4.40886	4.198	0.21086	4.78%	1.29
2019Q3	3.01396	3.01241	0.00156	0.05%	0.01
2019Q4	4.70265	4.69611	0.00654	0.14%	0.04
2020Q1	6.2702	6.28211	-0.01191	-0.19%	(0.07)
2020Q2	4.68371	4.59361	0.0901	1.92%	0.55
2020Q3	2.97671	3.03638	-0.05967	-2.00%	(0.37)
2020Q4	4.42273	4.66398	-0.24126	-5.46%	(1.48)
2021Q1	6.79518	6.84941	-0.05423	-0.80%	(0.33)
2021Q2	4.04871	4.17551	-0.1268	-3.13%	(0.78)
2021Q3	2.9096	2.6828	0.22679	7.79%	1.39
2021Q4	4.00983	4.3123	-0.30247	-7.54%	(1.85)
2022Q1	6.15961	6.04903	0.11058	1.80%	0.68
2022Q2	4.16516	4.18704	-0.02188	-0.53%	(0.13)
2022Q3	2.83838	2.68761	0.15077	5.31%	0.92

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	4.009833	4.403751	-0.39	-9.8%
Q1 2022	6.159606	6.255085	-0.10	-1.6%
Q2 2022	4.165163	4.005815	0.16	3.8%
Q3 2022	2.838385	2.714715	0.12	4.4%
Total	17.17	17.38	-0.21	-1.2%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	3.251974	3.258838	-0.006864	0%
S_AFT_D21Q2*S_RRNGP_ROLL12	-0.024478	-0.022206	-0.002272	9%
S_Q1_EDD+S_Q2_EDD+S_Q4_EDD	0.001047	0.001042	5E-06	0%
S_D12Q2_D14Q3	0.583441	0.582001	0.00144	0%
S_D18Q3_D20Q4	-0.210801	-0.211258	0.000457	0%
S_D13Q1	0.360716	0.37025	-0.009534	-3%
S_D14Q1	-0.871096	-0.859747	-0.011349	1%
AR(2)	-0.692153	-0.677325	-0.014828	2%

LLFUPC Brockton S&T
C. Low Load Factor User Per Customer - Sales & Transportation
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
B_LLF_UPC_S_T	15	0.999	2.034

ARIMA Model Parameters

B_LLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	37.45066	8.351	4.48	0.000
	B_LLFNGP_ST_ROLL12(-1)	-1.32756	0.679	-1.95	0.057
	B_Q1_EDD	0.074967	0.001	140.86	0.000
	B_Q4_EDD	0.053441	0.001	52.46	0.000
	B_Q2_EDD	0.063589	0.001	49.54	0.000
	B_D21Q1	28.7288	4.487	6.40	0.000
	B_D15Q1+B_D15Q2	16.88702	3.120	5.41	0.000
	B_D18Q1+B_D18Q2	15.35407	3.146	4.88	0.000
	B_D18Q4	15.25693	4.408	3.46	0.001
	B_D22Q1	22.57358	4.540	4.97	0.000
	B_D09Q3	9.454964	4.380	2.16	0.036
	B_D19Q4	11.67056	4.421	2.64	0.011
	B_D20Q1	14.56538	4.424	3.29	0.002
	B_D19Q2	10.37217	4.351	2.38	0.022
	B_D19Q1	11.73169	4.458	2.63	0.012

Variable	Definition	Explanation	Dummy Variable Support
B_LLFNGP_ST_ROLL12(-1)	Rolling 12 quarter natural gas price for low load factor customers in Brockton ($2022/MMBtu) lagged one quarter		
B_Q1_EDD	Effective Degree Days in Brockton in Q1	A	
B_Q4_EDD	Effective Degree Days in Brockton in Q4	A	
B_Q2_EDD	Effective Degree Days in Brockton in Q2	A	
B_D21Q1	Binary variable equal to 1 in 2021Q1		2
B_D15Q1+B_D15Q2	Binary variable equal to 1 in 2015Q1 and 2015Q2		2
B_D18Q1+B_D18Q2	Binary variable equal to 1 in 2018Q1 and 2018Q2		2
B_D18Q4	Binary variable equal to 1 in 2018Q4		2
B_D22Q1	Binary variable equal to 1 in 2022Q1		2
B_D09Q3	Binary variable equal to 1 in 2009Q3		2
B_D19Q4	Binary variable equal to 1 in 2019Q4		2
B_D20Q1	Binary variable equal to 1 in 2020Q1		2
B_D19Q2	Binary variable equal to 1 in 2019Q2		2
B_D19Q1	Binary variable equal to 1 in 2019Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

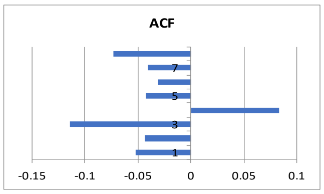
N	Adjusted R2	F Statistic
59	0.998114	2193.83

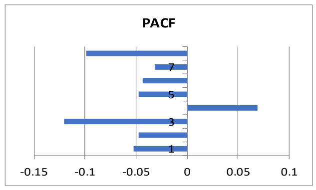
Chow Test Stats	N	k	SSR
Combined	30	15	753.73
1	32	7	272.53
2	27	13	291.80

Chow Stat:	0.649
P-Value:	0.810032

Heteroscedasticity - White's Test	
White Stat	0.60
Significance (p-value)	0.85

Correlations														
	B_LLFNGP_ST_ROLL12(-1)	B_Q1_EDD	B_Q4_EDD	B_Q2_EDD	B_D21Q1	B_D15Q1+B_D15Q2	B_D18Q1+B_D18Q2	B_D18Q4	B_D22Q1	B_D09Q3	B_D19Q4	B_D20Q1	B_D19Q2	B_D19Q1
B_LLFNGP_ST_ROLL12(-1)	1	0.062556	0.0191	-0.008662	-0.18925	0.020502	-0.107588	-0.1047	-0.21901	0.163901	-0.1424	-0.15197	-0.12596	-0.11557
B_Q1_EDD	0.062556	1	-0.321597	-0.336359	0.190741	0.148342	0.111872	-0.07617	0.196124	-0.07617	-0.07617	0.181233	-0.07617	0.230543
B_Q4_EDD	0.0191	-0.321597	1	-0.321443	-0.07279	-0.103845	-0.103845	0.269552	-0.07279	-0.07279	0.255842	-0.07279	-0.07279	-0.07279
B_Q2_EDD	-0.008662	-0.336359	-0.321443	1	-0.07614	0.121658	0.121122	-0.07614	-0.07614	-0.07614	-0.07614	-0.07614	0.21852	-0.07614
B_D21Q1	-0.189246	0.190741	-0.072793	-0.076135	1	-0.024596	-0.024596	-0.01724	-0.01724	-0.01724	-0.01724	-0.01724	-0.01724	-0.01724
B_D15Q1+B_D15Q2	0.020502	0.148342	-0.103845	0.121658	-0.0246	1	-0.035088	-0.0246	-0.0246	-0.0246	-0.0246	-0.0246	-0.0246	-0.0246
B_D18Q1+B_D18Q2	-0.107588	0.111872	-0.103845	0.121122	-0.0246	-0.035088	1	-0.0246	-0.0246	-0.0246	-0.0246	-0.0246	-0.0246	-0.0246
B_D18Q4	-0.104699	-0.076171	0.269552	-0.076135	-0.01724	-0.024596	-0.024596	1	-0.01724	-0.01724	-0.01724	-0.01724	-0.01724	-0.01724
B_D22Q1	-0.219012	0.196124	-0.072793	-0.076135	-0.01724	-0.024596	-0.024596	-0.01724	1	-0.01724	-0.01724	-0.01724	-0.01724	-0.01724
B_D09Q3	0.163901	-0.076171	-0.072793	-0.076135	-0.01724	-0.024596	-0.024596	-0.01724	-0.01724	1	-0.01724	-0.01724	-0.01724	-0.01724
B_D19Q4	-0.142402	-0.076171	0.255842	-0.076135	-0.01724	-0.024596	-0.024596	-0.01724	-0.01724	-0.01724	1	-0.01724	-0.01724	-0.01724
B_D20Q1	-0.151973	0.181233	-0.072793	-0.076135	-0.01724	-0.024596	-0.024596	-0.01724	-0.01724	-0.01724	-0.01724	1	-0.01724	-0.01724
B_D19Q2	-0.12596	-0.076171	-0.072793	0.21852	-0.01724	-0.024596	-0.024596	-0.01724	-0.01724	-0.01724	-0.01724	-0.01724	1	-0.01724
B_D19Q1	-0.115572	0.230543	-0.072793	-0.076135	-0.01724	-0.024596	-0.024596	-0.01724	-0.01724	-0.01724	-0.01724	-0.01724	-0.01724	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_llf_upc_s_t Model	ACF	-0.052	-0.044	-0.114	0.083	-0.043	-0.031	-0.041	-0.073
	SE	0.260	0.260	0.260	0.260	0.260	0.260	0.260	0.260
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_llf_upc_s_t Model		-0.052	-0.047	-0.12	0.069	-0.047	-0.043	-0.032	-0.099
	SE	0.260	0.260	0.260	0.260	0.260	0.260	0.260	0.260

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2008Q1	267.165	263.156	4.00847	1.50%	0.97
2008Q2	102.134	101.432	0.70196	0.69%	0.17
2008Q3	23.9677	19.0573	4.91039	20.49%	1.19
2008Q4	113.666	113.49	0.17568	0.15%	0.04
2009Q1	284.026	290.622	-6.59617	-2.32%	(1.59)
2009Q2	102.744	98.6244	4.11976	4.01%	1.00
2009Q3	28.9167	28.9167	-7.1E-15	0.00%	(0.00)
2009Q4	103.011	107.215	-4.20331	-4.08%	(1.02)
2010Q1	280.098	275.372	4.72572	1.69%	1.14
2010Q2	78.9856	79.407	-0.42136	-0.53%	(0.10)
2010Q3	21.3419	19.7666	1.57523	7.38%	0.38
2010Q4	111.517	113.868	-2.35141	-2.11%	(0.57)
2011Q1	292.626	287.819	4.80702	1.64%	1.16
2011Q2	105.083	104.18	0.90231	0.86%	0.22
2011Q3	20.5188	19.9583	0.56048	2.73%	0.14
2011Q4	93.626	95.8894	-2.26343	-2.42%	(0.55)
2012Q1	234.838	240.214	-5.37602	-2.29%	(1.30)
2012Q2	77.963	84.5384	-6.57544	-8.43%	(1.59)
2012Q3	21.2063	20.2254	0.98088	4.63%	0.24
2012Q4	108.42	108.794	-0.37437	-0.35%	(0.09)
2013Q1	268.832	272.1	-3.26845	-1.22%	(0.79)
2013Q2	100.785	103.485	-2.70049	-2.68%	(0.65)
2013Q3	20.352	20.4936	-0.14162	-0.70%	(0.03)
2013Q4	118.257	119.588	-1.3306	-1.13%	(0.32)
2014Q1	304.784	304.739	0.04517	0.01%	0.01
2014Q2	108.041	106.686	1.35514	1.25%	0.33
2014Q3	20.7702	20.7519	0.01823	0.09%	0.00
2014Q4	110.97	113.358	-2.3881	-2.15%	(0.58)
2015Q1	339.292	336.2	3.09159	0.91%	0.75
2015Q2	120.442	123.533	-3.09159	-2.57%	(0.75)
2015Q3	25.7526	20.9625	4.79006	18.60%	1.16
2015Q4	95.1822	99.893	-4.71085	-4.95%	(1.14)
2016Q1	246.409	243.617	2.7914	1.13%	0.67
2016Q2	109.967	101.767	8.19945	7.46%	1.98
2016Q3	22.9326	21.2304	1.70216	7.42%	0.41
2016Q4	106.145	108.942	-2.79638	-2.63%	(0.68)
2017Q1	251.201	257.429	-6.22797	-2.48%	(1.50)
2017Q2	108.933	108.258	0.67467	0.62%	0.16
2017Q3	17.898	21.5502	-3.65222	-20.41%	(0.88)
2017Q4	102.804	98.9122	3.89176	3.79%	0.94
2018Q1	294.055	293.146	0.90944	0.31%	0.22
2018Q2	121.784	122.694	-0.90944	-0.75%	(0.22)
2018Q3	20.848	21.9214	-1.07342	-5.15%	(0.26)
2018Q4	134.2	134.2	7.1E-15	0.00%	(0.00)
2019Q1	287.916	287.916	-8.5E-14	0.00%	(0.00)
2019Q2	110.86	110.86	2.8E-14	0.00%	(0.00)
2019Q3	21.264	22.3198	-1.05575	-4.96%	(0.26)
2019Q4	127.094	127.094	-1.6E-14	0.00%	(0.00)
2020Q1	250.256	250.256	2.5E-14	0.00%	(0.00)
2020Q2	110.31	111.548	-1.23812	-1.12%	(0.30)
2020Q3	20.9208	22.6765	-1.75576	-8.39%	(0.42)
2020Q4	107.425	96.4778	10.9475	10.19%	2.65
2021Q1	272.652	272.652	-7.1E-15	0.00%	(0.00)
2021Q2	98.5787	97.7904	0.78837	0.80%	0.19
2021Q3	22.4525	22.9803	-0.52776	-2.35%	(0.13)
2021Q4	107.746	99.3638	8.38214	7.78%	2.03
2022Q1	271.241	271.241	-3.2E-14	0.00%	(0.00)
2022Q2	93.0345	96.1841	-3.1496	-3.39%	(0.76)
2022Q3	16.4818	23.3571	-6.87532	-41.71%	(1.66)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	107.7459	98.99977	8.75	8.1%
Q1 2022	271.241	248.9445	22.30	8.2%
Q2 2022	93.03449	96.62315	-3.59	-3.9%
Q3 2022	16.48183	23.9768	-7.49	-45.5%
Total	488.50	468.54	19.96	4.1%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	37.45066	39.06184	-1.61118	-4%
B_LLFNGP_ST_ROLL12(-1)	-1.32756	-1.420958	0.093398	-7%
B_Q1_EDD	0.074967	0.074858	0.000109	0%
B_Q4_EDD	0.053441	0.052767	0.000674	1%
B_Q2_EDD	0.063589	0.063439	0.00015	0%
B_D21Q1	28.7288	28.46531	0.26349	1%
B_D15Q1+B_D15Q2	16.88702	16.75782	0.1292	1%
B_D18Q1+B_D18Q2	15.35407	15.13342	0.22065	1%
B_D18Q4	15.25693	15.95186	-0.69493	-5%
B_D22Q1	22.57358	0	22.57358	
B_D09Q3	9.454964	9.109369	0.345595	4%
B_D19Q4	11.67056	12.29115	-0.62059	-5%
B_D20Q1	14.56538	14.31561	0.24977	2%
B_D19Q2	10.37217	10.01563	0.35654	3%
B_D19Q1	11.73169	11.56563	0.16606	1%

LLFUPC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
L_LLF_UPC_S_T	11	0.998	2.643

ARIMA Model Parameters

L_LLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	36.12861	2.080	17.37	0.000
	L_LLFNGP_ST_ROLL12 *L_D15Q4_AFT	-0.273387	0.160	-1.71	0.094
	L_Q1_EDD	0.105683	0.001	133.33	0.000
	L_Q4_EDD	0.07766	0.001	52.98	0.000
	L_Q2_EDD	0.09765	0.002	52.47	0.000
	L_D09Q1	46.15593	7.419	6.22	0.000
	L_D11Q1	31.43296	7.403	4.25	0.000
	L_D09Q2+L_D09Q3	28.3977	5.206	5.46	0.000
	L_D10Q1	19.32227	7.371	2.62	0.012
	L_D19Q4	15.81378	7.343	2.15	0.036
	L_D17Q1	-16.17577	7.336	-2.21	0.032

Variable	Definition	Explanation	Dummy Variable Support
L_LLFNGP_ST_ROLL12*L_D15Q4_AFT	Rolling 12 quarter natural gas price for low load factor customers in Lawrence ($2022/MMBtu) from 2015Q4	B	
L_Q1_EDD	Effective Degree Days in Lawrence in Q1	A	
L_Q4_EDD	Effective Degree Days in Lawrence in Q4	A	
L_Q2_EDD	Effective Degree Days in Lawrence in Q2	A	
L_D09Q1	Binary variable equal to 1 in 2009Q1		2
L_D11Q1	Binary variable equal to 1 in 2011Q1		2
L_D09Q2+L_D09Q3	Binary variable equal to 1 in 2009Q2 and 2009Q3		2
L_D10Q1	Binary variable equal to 1 in 2010Q1		2
L_D19Q4	Binary variable equal to 1 in 2019Q4		2
L_D17Q1	Binary variable equal to 1 in 2017Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
60	0.997457	2315.632

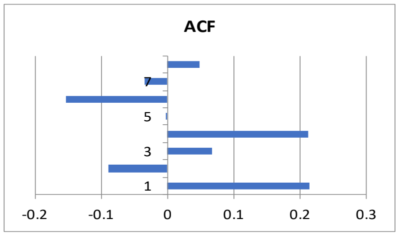
Chow Test Stats	N	k	SSR
Combined	60	11	2,389.60
1	29	8	1,156.29
2	31	7	915.14

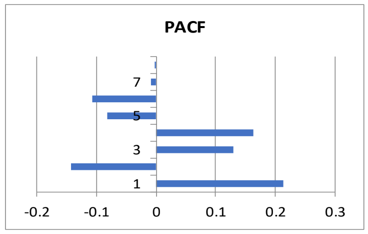
Chow Stat:	0.531
P-Value:	0.870099

Heteroscedasticity - White's Test	
White Stat	0.88
Significance (p-value)	0.56

Correlations

	L_LLFNGP_ST_ROLL12 *L_D15Q4_AFT	L_Q1_EDD	L_Q4_EDD	L_Q2_EDD	L_D09Q1	L_D11Q1	L_D09Q2+L_D09Q3	L_D10Q1	L_D19Q4	L_D17Q1
L_LLFNGP_ST_ROLL12*L_D15Q4_AFT	1	-0.026785	-0.014418	0.000846	-0.12153	-0.121526	-0.173339	-0.12153	0.134739	0.151918
L_Q1_EDD	-0.026785	1	-0.329732	-0.329183	0.249383	0.242561	-0.106652	0.227615	-0.07477	0.207865
L_Q4_EDD	-0.014418	-0.329732	1	-0.329047	-0.07474	-0.074742	-0.106609	-0.07474	0.241971	-0.07474
L_Q2_EDD	0.000846	-0.329183	-0.329047	1	-0.07462	-0.074618	0.103364	-0.07462	-0.07462	-0.07462
L_D09Q1	-0.121526	0.249383	-0.074742	-0.074618	1	-0.016949	-0.024175	-0.01695	-0.01695	-0.01695
L_D11Q1	-0.121526	0.242561	-0.074742	-0.074618	-0.01695	1	-0.024175	-0.01695	-0.01695	-0.01695
L_D09Q2+L_D09Q3	-0.173339	-0.106652	-0.106609	0.103364	-0.02418	-0.024175	1	-0.02418	-0.02418	-0.02418
L_D10Q1	-0.121526	0.227615	-0.074742	-0.074618	-0.01695	-0.016949	-0.024175	1	-0.01695	-0.01695
L_D19Q4	0.134739	-0.074773	0.241971	-0.074618	-0.01695	-0.016949	-0.024175	-0.01695	1	-0.01695
L_D17Q1	0.151918	0.207865	-0.074742	-0.074618	-0.01695	-0.016949	-0.024175	-0.01695	-0.01695	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_llf_upc_s_t Model	ACF	0.214	-0.09	0.068	0.212	-0.003	-0.154	-0.034	0.048
	SE	0.258	0.258	0.258	0.258	0.258	0.258	0.258	0.258
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_llf_upc_s_t Model		0.214	-0.142	0.129	0.164	-0.081	-0.107	-0.008	-0.002
	SE	0.258	0.258	0.258	0.258	0.258	0.258	0.258	0.258

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2007Q4	180.791	179.06	1.73094	0.96%	0.25
2008Q1	421.007	405.922	15.0843	3.58%	2.16
2008Q2	184.221	177.415	6.80689	3.69%	0.97
2008Q3	38.6222	36.1286	2.49355	6.46%	0.36
2008Q4	186.758	183.993	2.76497	1.48%	0.40
2009Q1	484.709	484.709	-4.3E-14	0.00%	(0.00)
2009Q2	199.891	194.508	5.38296	2.69%	0.77
2009Q3	59.1434	64.5263	-5.38296	-9.10%	(0.77)
2009Q4	180.556	175.979	4.57726	2.54%	0.66
2010Q1	430.851	430.851	-7.1E-15	0.00%	(0.00)
2010Q2	143.889	139.959	3.93045	2.73%	0.56
2010Q3	36.2343	36.1286	0.10564	0.29%	0.02
2010Q4	184.278	184.622	-0.34374	-0.19%	(0.05)
2011Q1	461.516	461.516	2.8E-14	0.00%	(0.00)
2011Q2	187.957	177.359	10.5983	5.64%	1.52
2011Q3	39.7633	36.1286	3.63474	9.14%	0.52
2011Q4	152.714	154.841	-2.12712	-1.39%	(0.30)
2012Q1	369.327	367.398	1.92811	0.52%	0.28
2012Q2	138.149	145.446	-7.2966	-5.28%	(1.04)
2012Q3	37.4869	36.1286	1.35833	3.62%	0.19
2012Q4	169.69	175.913	-6.22247	-3.67%	(0.89)
2013Q1	394.034	409.807	-15.7733	-4.00%	(2.26)
2013Q2	168.325	175.117	-6.79264	-4.04%	(0.97)
2013Q3	31.3337	36.1286	-4.79495	-15.30%	(0.69)
2013Q4	176.734	192.351	-15.6168	-8.84%	(2.24)
2014Q1	453.9	457.823	-3.92236	-0.86%	(0.56)
2014Q2	191.766	181.823	9.94358	5.19%	1.42
2014Q3	33.8927	36.1286	-2.23591	-6.60%	(0.32)
2014Q4	177.974	181.408	-3.43372	-1.93%	(0.49)
2015Q1	479.211	476.649	2.56217	0.53%	0.37
2015Q2	183.014	179.926	3.08839	1.69%	0.44
2015Q3	33.644	36.1286	-2.48463	-7.39%	(0.36)
2015Q4	150.656	159.778	-9.1215	-6.05%	(1.31)
2016Q1	369.805	365.043	4.76225	1.29%	0.68
2016Q2	169.156	168.168	0.98768	0.58%	0.14
2016Q3	38.6647	32.6366	6.02804	15.59%	0.86
2016Q4	163.815	171.755	-7.93962	-4.85%	(1.14)
2017Q1	367.377	367.377	1.2E-13	0.00%	(0.00)
2017Q2	174.662	179.519	-4.85619	-2.78%	(0.70)
2017Q3	30.3261	32.6999	-2.3738	-7.83%	(0.34)
2017Q4	157.72	155.269	2.45111	1.55%	0.35

2018Q1	415.515	417.487	-1.9714	-0.47%	(0.28)
2018Q2	168.123	175.818	-7.69593	-4.58%	(1.10)
2018Q3	33.8048	32.7904	1.01446	3.00%	0.15
2018Q4	199.936	188.924	11.0119	5.51%	1.58
2019Q1	417.575	412.552	5.02253	1.20%	0.72
2019Q2	172.447	166.953	5.49385	3.19%	0.79
2019Q3	34.2451	32.8686	1.37644	4.02%	0.20
2019Q4	194.914	194.914	-3.2E-14	0.00%	(0.00)
2020Q1	352.321	356.736	-4.41576	-1.25%	(0.63)
2020Q2	161.862	169.318	-7.45629	-4.61%	(1.07)
2020Q3	36.6381	32.9487	3.68936	10.07%	0.53
2020Q4	170.891	157.074	13.8175	8.09%	1.98
2021Q1	375.237	378.517	-3.28062	-0.87%	(0.47)
2021Q2	142.932	146.934	-4.00181	-2.80%	(0.57)
2021Q3	33.1197	33.0099	0.10978	0.33%	0.02
2021Q4	160.518	148.904	11.6143	7.24%	1.66
2022Q1	376.875	376.775	0.09998	0.03%	0.01
2022Q2	135.919	147.309	-11.3899	-8.38%	(1.63)
2022Q3	30.5649	33.1045	-2.53961	-8.31%	(0.36)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	160.5178	148.3157	12.20	7.6%
Q1 2022	376.8754	376.778	0.10	0.0%
Q2 2022	135.9187	147.9524	-12.03	-8.9%
Q3 2022	30.56487	33.28919	-2.72	-8.9%
Total	703.88	706.34	-2.46	-0.3%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	36.12861	36.32164	-0.19303	-1%
L_LLFNGP_ST_ROLL12*L_D1	-0.273387	-0.27414	0.000753	0%
L_Q1_EDD	0.105683	0.105627	5.6E-05	0%
L_Q4_EDD	0.07766	0.077142	0.000518	1%
L_Q2_EDD	0.09765	0.098043	-0.000393	0%
L_D09Q1	46.15593	46.1759	-0.01997	0%
L_D11Q1	31.43296	31.44845	-0.01549	0%
L_D09Q2+L_D09Q3	28.3977	27.94345	0.45425	2%
L_D10Q1	19.32227	19.32793	-0.00566	0%
L_D19Q4	15.81378	16.60414	-0.79036	-5%
L_D17Q1	-16.17577	-16.17357	-0.0022	0%

LLFUPC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
S_LLF_UPC_S_T	9	0.997	2.652

ARIMA Model Parameters

S_LLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	41.86799	8.167	5.13	0.000
	S_LLFNGP_ST(-4)	-1.093394	0.684	-1.60	0.116
	S_Q1_EDD	0.09285	0.002	57.30	0.000
	S_Q2_EDD+S_Q4_EDD	0.078779	0.003	24.20	0.000
	S_D20Q4+S_D20Q2	-20.07111	4.840	-4.15	0.000
	S_D13Q1	-24.13269	6.179	-3.91	0.000
	S_D21Q4	-17.87073	7.841	-2.28	0.027
	S_D13Q4	-11.77705	6.230	-1.89	0.064
	AR(4)	0.561238	0.076	7.34	0.000

Variable	Definition	Explanation	Dummy Variable Support
S_LLFNGP_ST(-4)	Natural gas price for low load factor customers in Springfield ($2022/MMBtu) lagged four quarters		
S_Q1_EDD	Effective Degree Days in Springfield in Q1	A	
S_Q2_EDD+S_Q4_EDD	Effective Degree Days in Springfield in Q2 and Q4	A	
S_D20Q4+S_D20Q2	Binary variable equal to 1 in 2020Q4 and 2020Q2		2
S_D13Q1	Binary variable equal to 1 in 2013Q1		2
S_D21Q4	Binary variable equal to 1 in 2021Q4		2
S_D13Q4	Binary variable equal to 1 in 2013Q4		2
AR(4)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

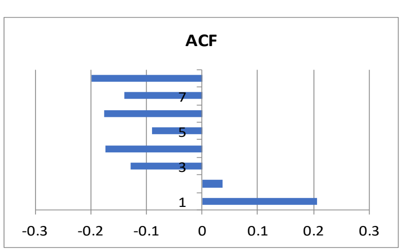
N	Adjusted R2	F Statistic
63	0.996336	2108.57

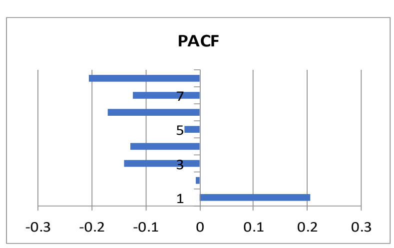
Chow Test Stats	N	k	SSR
Combined	63	9	2,671.99
1	31	7	1,348.00
2	32	7	1,039.37

Chow Stat:	0.596
P-Value:	0.793324

Heteroscedasticity - White's Test	
White Stat	2108.57
Significance (p-value)	0.42

Correlations	S_LLFNGP_ST(-4)	S_Q1_EDD	S_Q2_EDD+S_Q4_EDD	S_D20Q4+S_D20Q2	S_D21Q4	S_D13Q1	S_D13Q4
S_LLFNGP_ST(-4)	1	0.046781	-0.020966	-0.22665	-0.18459	0.032089	0.015177
S_Q1_EDD	0.046781	1	-0.549481	-0.105191	-0.07378	0.213896	-0.07378
S_Q2_EDD+S_Q4_EDD	-0.020966	-0.549481	1	0.209075	0.169216	-0.120124	0.199111
S_D20Q4+S_D20Q2	-0.22665	-0.105191	0.209075	1	-0.023	-0.022996	-0.023
S_D21Q4	-0.184593	-0.073779	0.169216	-0.022996	1	-0.016129	-0.01613
S_D13Q1	0.032089	0.213896	-0.120124	-0.022996	-0.01613	1	-0.01613
S_D13Q4	0.015177	-0.073779	0.199111	-0.022996	-0.01613	-0.016129	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_llf_upc_s_t Model	ACF	0.206	0.037	-0.128	-0.174	-0.091	-0.175	-0.139	-0.198
	SE	0.252	0.252	0.252	0.252	0.252	0.252	0.252	0.252
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_llf_upc_s_t Model		0.206	-0.006	-0.14	-0.128	-0.027	-0.171	-0.123	-0.205
	SE	0.252	0.252	0.252	0.252	0.252	0.252	0.252	0.252

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2007Q1	291.15	305.596	-14.4463	-4.96%	(2.05)
2007Q2	111.597	101.919	9.67721	8.67%	1.38
2007Q3	24.7794	20.1151	4.66428	18.82%	0.66
2007Q4	133.705	134.468	-0.76307	-0.57%	(0.11)
2008Q1	306.085	304.679	1.40529	0.46%	0.20
2008Q2	102.494	112.472	-9.97793	-9.74%	(1.42)
2008Q3	25.8914	26.8699	-0.97847	-3.78%	(0.14)
2008Q4	151.444	155.746	-4.30204	-2.84%	(0.61)
2009Q1	359.916	350.707	9.20903	2.56%	1.31
2009Q2	118.897	109.418	9.47936	7.97%	1.35
2009Q3	33.5635	28.0216	5.54193	16.51%	0.79
2009Q4	148.753	151.924	-3.17052	-2.13%	(0.45)
2010Q1	339	340.303	-1.30385	-0.38%	(0.19)
2010Q2	98.1895	94.5719	3.61759	3.68%	0.51
2010Q3	33.5808	31.8943	1.68653	5.02%	0.24
2010Q4	160.151	161.211	-1.06033	-0.66%	(0.15)
2011Q1	356.532	364.47	-7.9387	-2.23%	(1.13)
2011Q2	127.981	124.353	3.62755	2.83%	0.52
2011Q3	32.9677	32.0394	0.92834	2.82%	0.13
2011Q4	140.989	139.615	1.3739	0.97%	0.20
2012Q1	302.777	293.169	9.60811	3.17%	1.37
2012Q2	98.4624	100.353	-1.8903	-1.92%	(0.27)
2012Q3	35.2286	31.8575	3.37107	9.57%	0.48
2012Q4	156.263	157.083	-0.81975	-0.52%	(0.12)
2013Q1	319.392	322.07	-2.67814	-0.84%	(0.38)
2013Q2	110.308	124.963	-14.6548	-13.29%	(2.08)
2013Q3	23.7772	33.2171	-9.43987	-39.70%	(1.34)
2013Q4	157.72	161.385	-3.66486	-2.32%	(0.52)
2014Q1	383.036	387.808	-4.77185	-1.25%	(0.68)
2014Q2	132.689	117.482	15.2071	11.46%	2.16
2014Q3	29.252	26.8872	2.36484	8.08%	0.34
2014Q4	150.104	156.634	-6.52996	-4.35%	(0.93)
2015Q1	405.18	394.566	10.6133	2.62%	1.51
2015Q2	132.744	125.524	7.22003	5.44%	1.03
2015Q3	30.072	30.0706	0.00141	0.00%	0.00
2015Q4	125.204	138.589	-13.3851	-10.69%	(1.90)
2016Q1	304.327	314.515	-10.1881	-3.35%	(1.45)
2016Q2	121.106	128.665	-7.55859	-6.24%	(1.07)
2016Q3	29.8382	30.5256	-0.6874	-2.30%	(0.10)
2016Q4	151.859	152.301	-0.44179	-0.29%	(0.06)
2017Q1	327.689	323.646	4.0425	1.23%	0.57
2017Q2	132.661	128.448	4.21218	3.18%	0.60
2017Q3	25.7429	30.3874	-4.64455	-18.04%	(0.66)
2017Q4	152.592	144.492	8.09984	5.31%	1.15
2018Q1	362.064	359.194	2.87001	0.79%	0.41
2018Q2	140.008	134.014	5.99352	4.28%	0.85
2018Q3	25.8023	28.1254	-2.32309	-9.00%	(0.33)
2018Q4	187.313	182.012	5.3004	2.83%	0.75
2019Q1	361.2	357.843	3.35734	0.93%	0.48
2019Q2	132.669	120.525	12.144	9.15%	1.73
2019Q3	28.5072	28.4421	0.0651	0.23%	0.01
2019Q4	173.97	172.179	1.79103	1.03%	0.25
2020Q1	319.83	320.219	-0.38831	-0.12%	(0.06)
2020Q2	127.764	129.346	-1.58262	-1.24%	(0.22)
2020Q3	24.7128	30.0815	-5.3687	-21.72%	(0.76)
2020Q4	143.969	147.303	-3.33392	-2.32%	(0.47)
2021Q1	339.464	348.312	-8.84755	-2.61%	(1.26)
2021Q2	120.248	129.008	-8.76018	-7.29%	(1.25)
2021Q3	27.3767	27.9444	-0.56771	-2.07%	(0.08)
2021Q4	144.563	144.563	5E-13	0.00%	(0.00)
2022Q1	351.723	341.954	9.76898	2.78%	1.39
2022Q2	126.363	123.712	2.65103	2.10%	0.38
2022Q3	26.2024	29.6268	-3.42444	-13.07%	(0.49)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	144.5627	162.2219	-17.66	-12.2%
Q1 2022	351.7225	341.2999	10.42	3.0%
Q2 2022	126.3628	123.6255	2.74	2.2%
Q3 2022	26.2024	30.07007	-3.87	-14.8%
Total	648.85	657.22	-8.37	-1.3%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	41.86799	41.62875	0.23924	1%
S_LLFNGP_ST(-4)	-1.093394	-1.046399	-0.046995	4%
S_Q1_EDD	0.09285	0.092351	0.000499	1%
S_Q2_EDD+S_Q4_EDD	0.078779	0.078468	0.000311	0%
S_D20Q4+S_D20Q2	-20.07111	-19.94784	-0.12327	1%
S_D21Q4	-17.87073	0	-17.87073	
S_D13Q1	-24.13269	-23.91836	-0.21433	1%
S_D13Q4	-11.77705	-11.6838	-0.09325	1%
AR(4)	0.561238	0.560207	0.001031	0%

HLFUPC Brockton S&T
D. High Load Factor User Per Customer - Sales & Transportation
1. Brockton

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
B_HLF_UPC_S_T	15	0.980	3.399

ARIMA Model Parameters

B_HLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	429.6886	47.953	8.96	0.000
	B_HLFNGP_ST_ROLL12	-17.35574	5.559	-3.12	0.004
	B_Q1_EDD+B_Q2_EDD	0.050457	0.001	34.02	0.000
	B_Q4_EDD	0.03972	0.003	11.78	0.000
	B_D20Q2	-54.70514	11.987	-4.56	0.000
	B_D20Q3	-51.02549	12.266	-4.16	0.000
	B_D16Q4	-32.73405	12.439	-2.63	0.013
	B_D12Q4	-28.83478	13.005	-2.22	0.034
	B_D11Q2	33.58851	12.215	2.75	0.010
	B_D21Q3	36.99269	12.438	2.97	0.006
	B_D21Q4	-74.78198	12.828	-5.83	0.000
	B_D19Q2	34.95542	11.868	2.95	0.006
	B_D20Q4	-30.96988	12.570	-2.46	0.019
	B_D14Q3_AFT	15.92831	6.484	2.46	0.020
	B_D13Q4_14Q2	43.11756	8.047	5.36	0.000

Variable	Definition	Explanation	Dummy Variable Support
B_HLFNGP_ST_ROLL12	Rolling 12 quarter natural gas price for high load factor customers in Brockton ($2022/MMBtu)		
B_Q1_EDD+B_Q2_EDD	Effective Degree Days in Brockton in Q1 and Q2	A	
B_Q4_EDD	Effective Degree Days in Brockton in Q4	A	
B_D20Q2	Binary variable equal to 1 in 2020Q2		2
B_D20Q3	Binary variable equal to 1 in 2020Q3		2
B_D16Q4	Binary variable equal to 1 in 2016Q4		2
B_D12Q4	Binary variable equal to 1 in 2012Q4		2
B_D11Q2	Binary variable equal to 1 in 2011Q2		2
B_D21Q3	Binary variable equal to 1 in 2021Q3		2
B_D21Q4	Binary variable equal to 1 in 2021Q4		2
B_D19Q2	Binary variable equal to 1 in 2019Q2		2
B_D20Q4	Binary variable equal to 1 in 2020Q4		2
B_D14Q3_AFT	Binary variable equal to 1 from 2014Q3 on		1
B_D13Q4_14Q2	Binary variable equal to 1 from 2013Q4 to 2014Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

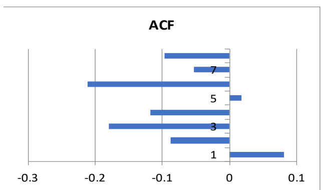
N	Adjusted R2	F Statistic
47	0.970609	109.5062

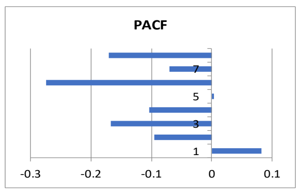
Chow Test Stats			
	N	k	SSR
Combined	47	15	4,268.95
1	16	8	631.18
2	31	11	2,665.37

Chow Stat:	0.334
P-Value:	0.980823

Heteroscedasticity - White's Test	
White Stat	1.46
Significance (p-value)	0.18

Correlations														
	B_HLFNGP_ST_ROLL12	B_Q1_EDD+B_Q2_EDD	B_Q4_EDD	B_D20Q2	B_D20Q3	B_D16Q4	B_D12Q4	B_D11Q2	B_D21Q3	B_D21Q4	B_D19Q2	B_D20Q4	B_D14Q3	B_D13Q4_14Q2
B_HLFNGP_ST_ROLL12	1	0.074539	0.018137	-0.160047	-0.17274	0.016785	0.162164	0.22007	-0.21227	-0.22372	-0.11016	-0.18382	-0.74767	0.209148
B_Q1_EDD+B_Q2_EDD	0.074539	1	-0.46996	0.025675	-0.12623	-0.126227	-0.12623	0.017651	-0.12623	-0.12623	0.007382	-0.12623	-0.08153	0.10606
B_Q4_EDD	0.018137	-0.46996	1	-0.080938	-0.08094	0.273742	0.277275	-0.08094	-0.08094	0.227992	-0.08094	0.217453	0.021064	0.093318
B_D20Q2	-0.160047	0.025675	-0.080938	1	-0.02174	-0.021739	-0.02174	-0.02174	-0.02174	-0.02174	-0.02174	-0.02174	0.096035	-0.0385
B_D20Q3	-0.172738	-0.126227	-0.080938	-0.021739	1	-0.021739	-0.02174	-0.02174	-0.02174	-0.02174	-0.02174	-0.02174	0.096035	-0.0385
B_D16Q4	0.016785	-0.126227	0.273742	-0.021739	-0.02174	1	-0.02174	-0.02174	-0.02174	-0.02174	-0.02174	-0.02174	0.096035	-0.0385
B_D12Q4	0.162164	-0.126227	0.277275	-0.021739	-0.02174	-0.021739	1	-0.02174	-0.02174	-0.02174	-0.02174	-0.02174	-0.22637	-0.0385
B_D11Q2	0.22007	0.017651	-0.080938	-0.021739	-0.02174	-0.021739	-0.02174	1	-0.02174	-0.02174	-0.02174	-0.02174	-0.22637	-0.0385
B_D21Q3	-0.212265	-0.126227	-0.080938	-0.021739	-0.02174	-0.021739	-0.02174	-0.02174	1	-0.02174	-0.02174	-0.02174	0.096035	-0.0385
B_D21Q4	-0.22372	-0.126227	0.227992	-0.021739	-0.02174	-0.021739	-0.02174	-0.02174	-0.02174	1	-0.02174	-0.02174	0.096035	-0.0385
B_D19Q2	-0.110158	0.007382	-0.080938	-0.021739	-0.02174	-0.021739	-0.02174	-0.02174	-0.02174	-0.02174	1	-0.02174	0.096035	-0.0385
B_D20Q4	-0.183816	-0.126227	0.217453	-0.021739	-0.02174	-0.021739	-0.02174	-0.02174	-0.02174	-0.02174	-0.02174	1	0.096035	-0.0385
B_D14Q3_AFT	-0.747669	-0.081526	0.021064	0.096035	0.096035	0.096035	-0.22637	-0.22637	0.096035	0.096035	0.096035	0.096035	1	-0.400892
B_D13Q4_14Q2	0.209148	0.10606	0.093318	-0.0385	-0.0385	-0.0385	-0.0385	-0.0385	-0.0385	-0.0385	-0.0385	-0.0385	-0.40089	1





Residual ACF									
Model			1	2	3	4	5	6	7	8
b_hlf_upc_s_t Model	ACF	0.082	-0.088	-0.18	-0.118	0.018	-0.212	-0.053	-0.097
	SE	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_hlf_upc_s_t Model		0.082	-0.095	-0.167	-0.103	0.004	-0.275	-0.07	-0.17
	SE	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residua
2011Q1	475.11	458.107	17.0026	3.58%	1.47
2011Q2	378.558	378.558	3.6E-14	0.00%	(0.00)
2011Q3	279.469	278.343	1.12598	0.40%	0.10
2011Q4	328.754	335.325	-6.57124	-2.00%	(0.57)
2012Q1	424.616	427.846	-3.22977	-0.76%	(0.28)
2012Q2	339.77	331.525	8.24521	2.43%	0.71
2012Q3	268.156	281.121	-12.9652	-4.83%	(1.12)
2012Q4	318.632	318.632	-1.1E-14	0.00%	(0.00)
2013Q1	440.451	451.69	-11.2386	-2.55%	(0.97)
2013Q2	350.959	348.644	2.31418	0.66%	0.20
2013Q3	288.61	283.293	5.31682	1.84%	0.46
2013Q4	387.887	400.582	-12.6951	-3.27%	(1.10)
2014Q1	521.635	518.783	2.85236	0.55%	0.25
2014Q2	406.184	396.341	9.84269	2.42%	0.85
2014Q3	320.467	301.473	18.995	5.93%	1.64
2014Q4	375.406	370.754	4.6516	1.24%	0.40
2015Q1	483.15	503.201	-20.0502	-4.15%	(1.74)
2015Q2	368.214	370.765	-2.55082	-0.69%	(0.22)
2015Q3	305.025	303.185	1.84019	0.60%	0.16
2015Q4	360.71	362.325	-1.61479	-0.45%	(0.14)
2016Q1	440.858	454.029	-13.1714	-2.99%	(1.14)
2016Q2	375.523	369.04	6.48243	1.73%	0.56
2016Q3	298.068	305.892	-7.82401	-2.62%	(0.68)
2016Q4	339.021	339.021	-2.3E-14	0.00%	(0.00)
2017Q1	476.246	466.13	10.1155	2.12%	0.88
2017Q2	384.788	376.684	8.10391	2.11%	0.70
2017Q3	305.341	308.424	-3.08323	-1.01%	(0.27)
2017Q4	365.578	366.593	-1.01555	-0.28%	(0.09)
2018Q1	462.91	482.438	-19.5281	-4.22%	(1.69)
2018Q2	373.717	378.916	-5.19825	-1.39%	(0.45)
2018Q3	298.46	312.043	-13.583	-4.55%	(1.18)
2018Q4	398.543	384.972	13.5709	3.41%	1.17
2019Q1	505.277	484.794	20.483	4.05%	1.77
2019Q2	411.544	411.544	5.3E-15	0.00%	(0.00)
2019Q3	317.776	315.174	2.60186	0.82%	0.23
2019Q4	387.436	385.111	2.32494	0.60%	0.20
2020Q1	479.479	460.308	19.171	4.00%	1.66
2020Q2	333.476	333.476	-2.3E-14	0.00%	(0.00)
2020Q3	267.353	267.353	-4.4E-14	0.00%	(0.00)
2020Q4	342.88	342.88	5.9E-14	0.00%	(0.00)
2021Q1	456.222	468.434	-12.2115	-2.68%	(1.06)
2021Q2	370.183	379.638	-9.45551	-2.55%	(0.82)
2021Q3	357.821	357.821	-1.8E-15	0.00%	(0.00)
2021Q4	303.476	303.476	2E-14	0.00%	(0.00)
2022Q1	477.339	474.231	3.10749	0.65%	0.27
2022Q2	389.878	381.373	8.50472	2.18%	0.74
2022Q3	313.946	324.612	-10.6661	-3.40%	(0.92)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	303.4759	378.3948	-74.92	-24.7%
Q1 2022	477.3386	473.8625	3.48	0.7%
Q2 2022	389.8782	381.6028	8.28	2.1%
Q3 2022	313.9457	325.2138	-11.27	-3.6%
Total	1484.64	1559.07	-74.44	-5.0%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	429.6886	431.4386	-1.75	0%
B_HLFNGP_ST_ROLL12	-17.35574	-17.50384	0.1481	-1%
B_Q1_EDD+B_Q2_EDD	0.050457	0.05014	0.000317	1%
B_Q4_EDD	0.03972	0.039413	0.000307	1%
B_D20Q2	-54.70514	-54.8045	0.09936	0%
B_D20Q3	-51.02549	-51.57426	0.54877	-1%
B_D16Q4	-32.73405	-32.67892	-0.05513	0%
B_D12Q4	-28.83478	-28.81327	-0.02151	0%
B_D11Q2	33.58851	33.55125	0.03726	0%
B_D21Q3	36.99269	36.42302	0.56967	2%
B_D21Q4	-74.78198	0	-74.78198	100%
B_D19Q2	34.95542	34.82913	0.12629	0%
B_D20Q4	-30.96988	-31.10076	0.13088	0%
B_D14Q3_AFT	15.92831	15.81281	0.1155	1%
B_D13Q4_14Q2	43.11756	43.33925	-0.22169	-1%

HLFUPC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
L_HLF_UPC_S_T	10	0.983	4.587

ARIMA Model Parameters

L_HLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	482.278	7.699	62.64	0.000
	L_HLFNGP_ST_ROLL12*L_D2017_AFT	-31.6083	1.804	-17.52	0.000
	L_Q1Q2_EDD	0.089615	0.002	37.78	0.000
	L_Q4_EDD	0.050774	0.005	10.76	0.000
	L_D2016	-76.98195	12.032	-6.40	0.000
	L_D10Q1_12Q2	35.6496	8.877	4.02	0.000
	L_D2010_2017*Q2	48.86333	8.814	5.54	0.000
	L_D20Q2	-61.25443	21.607	-2.83	0.007
	L_D21Q1	-50.48037	21.983	-2.30	0.027
	L_D15Q4	-45.91579	22.390	-2.05	0.047

Variable	Definition	Explanation	Dummy Variable Support
L_HLFNGP_ST_ROLL12*L_D2017_AFT	Rolling 12 quarter natural gas price for high load factor customers in Lawrence ($2022/MMBtu) after 2017Q1		
L_Q1Q2_EDD	Effective Degree Days in Lawrence in Q1 and Q2		
L_Q4_EDD	Effective Degree Days in Lawrence in Q4	A	
L_D2016	Binary variable equal to 1 in 2016	A	
L_D10Q1_12Q2	Binary variable equal to 1 from 2010Q1 to 2012Q2		2
L_D2010_2017*Q2	Binary variable equal to 1 in Q2 from 2010 to 2017		2
L_D20Q2	Binary variable equal to 1 in 2020Q2		2
L_D21Q1	Binary variable equal to 1 in 2021Q1		2
L_D15Q4	Binary variable equal to 1 in 2015Q4		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
51	0.978943	259.2725

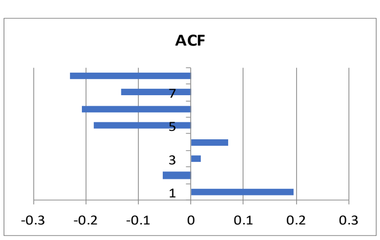
Chow Test Stats	N	k	SSR
Combined	51	10	18,156.62
1	23	5	5,757.92
2	28	9	10,999.25

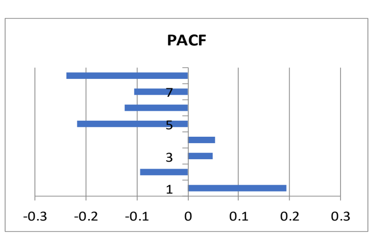
Chow Stat:	0.259
P-Value:	0.985826

Heteroscedasticity - White's Test	
White Stat	1.15
Significance (p-value)	0.35

Correlations

	L_HLFNGP_ST_ROLL12*L_D2017_AFT	L_Q1Q2_EDD	L_Q4_EDD	L_D2016	L_D10Q1_12Q2	L_D2010_201	L_D20Q2	L_D21Q1	L_D15Q4
L_HLFNGP_ST_ROLL12*L_D2017_AFT	1	0.000895	-0.049524	-0.264023	-0.44696	-0.275546	0.151845	0.147374	-0.12799
L_Q1Q2_EDD	0.000895	1	-0.470863	-0.020093	0.058709	0.039092	0.016063	0.199643	-0.12084
L_Q4_EDD	-0.049524	-0.470863	1	0.013126	-0.045958	-0.237681	-0.07793	-0.07793	0.230385
L_D2016	-0.264023	-0.020093	0.013126	1	-0.144075	0.074713	-0.04126	-0.04126	-0.04126
L_D10Q1_12Q2	-0.44696	0.058709	-0.045958	-0.144075	1	0.19438	-0.06984	-0.06984	-0.06984
L_D2010_2017*Q2	-0.275546	0.039092	-0.237681	0.074713	0.19438	1	-0.061	-0.061	-0.061
L_D20Q2	0.151845	0.016063	-0.077929	-0.041257	-0.069843	-0.060999	1	-0.02	-0.02
L_D21Q1	0.147374	0.199643	-0.077929	-0.041257	-0.069843	-0.060999	-0.02	1	-0.02
L_D15Q4	-0.12799	-0.120844	0.230385	-0.041257	-0.069843	-0.060999	-0.02	-0.02	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_hlf_upc_s_t Model	ACF	0.194	-0.053	0.018	0.071	-0.185	-0.208	-0.132	-0.23
	SE	0.280	0.280	0.280	0.280	0.280	0.280	0.280	0.280
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_hlf_upc_s_t Model		0.194	-0.094	0.05	0.054	-0.218	-0.125	-0.105	-0.238
	SE	0.280	0.280	0.280	0.280	0.280	0.280	0.280	0.280

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2010Q1	841.34	836.253	5.08715	0.60%	0.24
2010Q2	646.566	662.077	-15.5108	-2.40%	(0.74)
2010Q3	520.197	517.928	2.26962	0.44%	0.11
2010Q4	615.078	615.012	0.0656	0.01%	0.00
2011Q1	870.806	851.986	18.8193	2.16%	0.89
2011Q2	699.564	696.4	3.1642	0.45%	0.15
2011Q3	520.354	517.928	2.42676	0.47%	0.12
2011Q4	588.198	595.542	-7.34364	-1.25%	(0.35)
2012Q1	807.179	798.832	8.34719	1.03%	0.40
2012Q2	649.787	667.113	-17.3254	-2.67%	(0.82)
2012Q3	452.826	482.278	-29.4521	-6.50%	(1.40)
2012Q4	521.807	573.669	-51.8621	-9.94%	(2.46)
2013Q1	788.478	799.144	-10.6658	-1.35%	(0.51)
2013Q2	653.796	658.693	-4.89764	-0.75%	(0.23)
2013Q3	480.062	482.278	-2.21616	-0.46%	(0.11)
2013Q4	587.58	584.416	3.16381	0.54%	0.15
2014Q1	855.201	839.859	15.342	1.79%	0.73
2014Q2	679.167	664.847	14.3202	2.11%	0.68
2014Q3	500.758	482.278	18.4796	3.69%	0.88
2014Q4	594.4	577.262	17.1386	2.88%	0.81
2015Q1	860.976	855.823	5.15323	0.60%	0.24
2015Q2	686.005	663.106	22.8995	3.34%	1.09
2015Q3	485.182	482.278	2.90398	0.60%	0.14
2015Q4	519.523	519.523	-5.7E-14	0.00%	0.00
2016Q1	697.75	687.199	10.5513	1.51%	0.50
2016Q2	590.699	578.558	12.1416	2.06%	0.58
2016Q3	409.173	405.296	3.87722	0.95%	0.18
2016Q4	469.669	496.24	-26.5701	-5.66%	(1.26)
2017Q1	659.395	638.506	20.8892	3.17%	0.99
2017Q2	510.361	525.152	-14.7916	-2.90%	(0.70)
2017Q3	351.952	342.141	9.81024	2.79%	0.47
2017Q4	435.705	423.002	12.7034	2.92%	0.60
2018Q1	625.05	670.079	-45.0288	-7.20%	(2.14)
2018Q2	457.845	476.105	-18.2598	-3.99%	(0.87)
2018Q3	369.236	345.838	23.3977	6.34%	1.11
2018Q4	475.438	448.827	26.6119	5.60%	1.26
2019Q1	631.327	669.629	-38.3022	-6.07%	(1.82)
2019Q2	483.537	471.416	12.1212	2.51%	0.58
2019Q3	375.015	349.037	25.9787	6.93%	1.23
2019Q4	466.359	445.442	20.9165	4.49%	0.99
2020Q1	621.784	625.302	-3.51787	-0.57%	(0.17)
2020Q2	415.419	415.419	-5.7E-14	0.00%	0.00
2020Q3	330.315	352.31	-21.9953	-6.66%	(1.05)
2020Q4	403.672	434.153	-30.4805	-7.55%	(1.45)
2021Q1	596.118	596.118	-1.2E-13	0.00%	0.00
2021Q2	444.654	458.759	-14.1048	-3.17%	(0.67)
2021Q3	348.866	354.812	-5.94528	-1.70%	(0.28)
2021Q4	464.407	431.296	33.1105	7.13%	1.57
2022Q1	664.678	647.918	16.76	2.52%	0.80
2022Q2	471.803	462.364	9.43983	2.00%	0.45
2022Q3	339.057	358.677	-19.6202	-5.79%	(0.93)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	464.407	427.9146	36.49	7.9%
Q1 2022	664.6783	645.2742	19.40	2.9%
Q2 2022	471.8033	461.1372	10.67	2.3%
Q3 2022	339.0566	358.2556	-19.20	-5.7%
Total	1939.95	1892.58	47.36	2.4%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	482.278	483.8961	-1.6181	0%
L_HLFNGP_ST_ROLL12*L_D2017_AFT	-31.6083	-32.12979	0.52149	-2%
L_Q1Q2_EDD	0.089615	0.088943	0.000672	1%
L_Q4_EDD	0.050774	0.048824	0.00195	4%
L_D2016	-76.98195	-76.84485	-0.1371	0%
L_D10Q1_12Q2	35.6496	35.79066	-0.14106	0%
L_D2010_2017*Q2	48.86333	48.38202	0.48131	1%
L_D20Q2	-61.25443	-59.77617	-1.47826	2%
L_D21Q1	-50.48037	-47.77768	-2.70269	5%
L_D15Q4	-45.91579	-44.34078	-1.57501	3%

HLFUPC Springfield S&T
3. Springfield

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
S_HLF_UPC_S_T	17	0.981	4.693

ARIMA Model Parameters

S_HLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	449.0178	11.883	37.79	0.000
	S_HLFNGP_ST_ROLL12(-3)	-9.879969	2.185	-4.52	0.000
	S_Q1_EDD+S_Q2_EDD	0.058975	0.002	24.63	0.000
	S_Q4_EDD	0.04155	0.005	8.43	0.000
	S_D15Q4_AFT	221.5921	6.735	32.90	0.000
	S_D09Q1	-129.4447	23.346	-5.54	0.000
	S_D20Q2+S_D20Q3	-103.6926	16.594	-6.25	0.000
	S_D16Q4	-64.76036	23.346	-2.77	0.008
	S_D19Q2	53.54405	25.606	2.09	0.042
	S_D2014	43.94184	11.945	3.68	0.001
	S_D16Q2	66.85486	22.678	2.95	0.005
	S_D13Q2	63.84215	22.589	2.83	0.007
	S_D13Q4	66.50999	23.383	2.84	0.007
	S_D15Q2	52.33608	22.566	2.32	0.025
	S_D07Q3	-86.94687	25.028	-3.47	0.001
	S_D21Q4	-45.29095	23.338	-1.94	0.059
	S_D2019	32.28058	13.726	2.35	0.023

Variable	Definition	Explanation	Dummy Variable Support
S_HLFNGP_ST_ROLL12(-3)	Natural gas price for high load factor customers in Springfield ($2022) lagged three quarters		
S_Q1_EDD+S_Q2_EDD	Effective Degree Days in Springfield in Q1 and Q2	A	
S_Q4_EDD	Effective Degree Days in Springfield in Q4	A	
S_D15Q4_AFT	Binary variable equal to 1 from 2015Q4 on		1
S_D09Q1	Binary variable equal to 1 in 2009Q1		2
S_D20Q2+S_D20Q3	Binary variable equal to 1 in 2020Q2 and 2020Q3		2
S_D16Q4	Binary variable equal to 1 in 2016Q4		2
S_D19Q2	Binary variable equal to 1 in 2019Q2		2
S_D2014	Binary variable equal to 1 in 2014		2
S_D16Q2	Binary varaible equal to 1 in 2016Q2		2
S_D13Q2	Binary varaible equal to 1 in 2013Q2		2
S_D13Q4	Binary varaible equal to 1 in 2013Q4		2
S_D15Q2	Binary varaible equal to 1 in 2015Q2		2
S_D07Q3	Binary varaible equal to 0 in 2007Q3		2
S_D21Q4	Binary varaible equal to 2 in 2021Q4		2
S_D2019	Binary variable equal to 1 in 2019		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
62	0.97416	144.7313

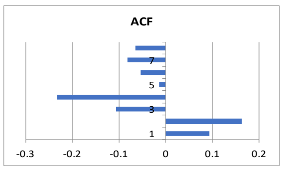
Chow Test Stats	N	k	SSR
Combined	62	17	21,833.47
1	46	13	16,331.25
2	16	8	1,326.76

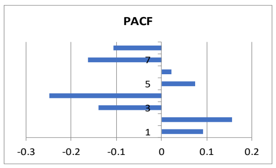
Chow Stat:	0.389
P-Value:	0.977186

Heteroscedasticity - White's Test	
White Stat	0.77
Significance (p-value)	0.71

Correlations

	S_HLFNGP_ST_ROLL12(-3)	S_Q1_EDD+S_Q2_EDD	S_Q4_EDD	S_D15Q4_AFT	S_D09Q1	S_D20Q2+S_D20Q3	S_D16Q4	S_D19Q2	S_D2014	S_D16Q2	S_D13Q2	S_D13Q4	S_D15Q2	S_D07Q3	S_D21Q4	S_D2019
S_HLFNGP_ST_ROLL12(-3)	1	-0.0087	0.041192	0.061631	0.09691	0.00144	0.024281	0.011757	0.088023	0.027169	0.053106	0.048909	0.034983	-0.419	-0.01303	0.021689
S_Q1_EDD+S_Q2_EDD	-0.0087	1	-0.455742	0.003434	0.233659	-0.057223	-0.10367	-0.00436	0.026768	0.003409	0.006433	-0.10367	0.002543	-0.10367	-0.10367	0.003877
S_Q4_EDD	0.041192	-0.455742	1	0.01518	-0.07207	-0.102763	0.227395	-0.07207	0.002328	-0.07207	-0.07207	0.25558	-0.07207	-0.07207	0.224898	0.01189
S_D15Q4_AFT	0.061631	0.003434	0.01518	1	-0.11619	0.201187	0.14109	0.14109	-0.23832	0.14109	-0.11619	-0.11619	-0.11619	-0.11619	0.14109	0.289385
S_D09Q1	0.09691	0.233659	-0.072066	-0.116192	1	-0.023376	-0.01639	-0.01639	-0.03362	-0.01639	-0.01639	-0.01639	-0.01639	-0.01639	-0.01639	-0.03362
S_D20Q2+S_D20Q3	0.00144	-0.057223	-0.102763	0.201187	-0.02338	1	-0.02338	-0.02338	-0.04795	-0.02338	-0.02338	-0.02338	-0.02338	-0.02338	-0.02338	-0.04795
S_D16Q4	0.024281	-0.103671	0.227395	0.14109	-0.01639	-0.023376	1	-0.01639	-0.03362	-0.01639	-0.01639	-0.01639	-0.01639	-0.01639	-0.01639	-0.03362
S_D19Q2	0.011757	-0.004363	-0.072066	0.14109	-0.01639	-0.023376	-0.01639	1	-0.03362	-0.01639	-0.01639	-0.01639	-0.01639	-0.01639	-0.01639	0.48755
S_D2014	0.088023	0.026768	0.002328	-0.238317	-0.03362	-0.047946	-0.03362	-0.03362	1	-0.03362	-0.03362	-0.03362	-0.03362	-0.03362	-0.03362	-0.06897
S_D16Q2	0.027169	0.003409	-0.072066	0.14109	-0.01639	-0.023376	-0.01639	-0.01639	-0.03362	1	-0.01639	-0.01639	-0.01639	-0.01639	-0.01639	-0.03362
S_D13Q2	0.053106	0.006433	-0.072066	-0.116192	-0.01639	-0.023376	-0.01639	-0.01639	-0.03362	-0.01639	1	-0.01639	-0.01639	-0.01639	-0.01639	-0.03362
S_D13Q4	0.048909	-0.103671	0.25558	-0.116192	-0.01639	-0.023376	-0.01639	-0.01639	-0.03362	-0.01639	-0.01639	1	-0.01639	-0.01639	-0.01639	-0.03362
S_D15Q2	0.034983	0.002543	-0.072066	-0.116192	-0.01639	-0.023376	-0.01639	-0.01639	-0.03362	-0.01639	-0.01639	-0.01639	1	-0.01639	-0.01639	-0.03362
S_D07Q3	-0.419	-0.103671	-0.072066	-0.116192	-0.01639	-0.023376	-0.01639	-0.01639	-0.03362	-0.01639	-0.01639	-0.01639	-0.01639	1	-0.01639	-0.03362
S_D21Q4	-0.013026	-0.103671	0.224898	0.14109	-0.01639	-0.023376	-0.01639	-0.01639	-0.03362	-0.01639	-0.01639	-0.01639	-0.01639	-0.01639	1	-0.03362
S_D2019	0.021689	0.003877	0.01189	0.289385	-0.03362	-0.047946	-0.03362	0.48755	-0.06897	-0.03362	-0.03362	-0.03362	-0.03362	-0.03362	-0.03362	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_hlf_upc_s_t Model	ACF	0.093	0.164	-0.107	-0.233	-0.014	-0.054	-0.081	-0.064
	SE	0.254	0.254	0.254	0.254	0.254	0.254	0.254	0.254
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_hlf_upc_s_t Model		0.093	0.157	-0.139	-0.249	0.074	0.022	-0.163	-0.106
	SE	0.254	0.254	0.254	0.254	0.254	0.254	0.254	0.254

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2007Q2	498.215	521.327	-23.1121	-4.64%	(1.05)
2007Q3	362.071	362.071	7.1E-14	0.00%	0.00
2007Q4	493.445	516.094	-22.6487	-4.59%	(1.03)
2008Q1	671.825	645.448	26.3767	3.93%	1.20
2008Q2	528.137	517.241	10.8956	2.06%	0.49
2008Q3	389.502	390.553	-1.05136	-0.27%	(0.05)
2008Q4	463.476	464.438	-0.96194	-0.21%	(0.04)
2009Q1	477.814	477.814	2.8E-14	0.00%	0.00
2009Q2	435.499	459.53	-24.0312	-5.52%	(1.09)
2009Q3	409.397	392.853	16.5437	4.04%	0.75
2009Q4	449.844	462.601	-12.7568	-2.84%	(0.58)
2010Q1	549.002	593.934	-44.9323	-8.18%	(2.04)
2010Q2	438.143	442.626	-4.48356	-1.02%	(0.20)
2010Q3	372.987	394.411	-21.4239	-5.74%	(0.97)
2010Q4	461.016	467.783	-6.7665	-1.47%	(0.31)
2011Q1	621.761	609.778	11.9827	1.93%	0.54
2011Q2	499.021	464.558	34.4622	6.91%	1.56
2011Q3	399.582	395.447	4.13532	1.03%	0.19
2011Q4	489.504	455.853	33.6516	6.87%	1.53
2012Q1	538.753	566.949	-28.1958	-5.23%	(1.28)
2012Q2	456.139	446.065	10.0744	2.21%	0.46
2012Q3	382.128	395.941	-13.8124	-3.61%	(0.63)
2012Q4	467.46	464.032	3.42767	0.73%	0.16
2013Q1	607.117	595.927	11.1903	1.84%	0.51
2013Q2	530.804	530.804	-7.8E-14	0.00%	0.00
2013Q3	409.988	396.838	13.1493	3.21%	0.60
2013Q4	539.663	539.663	7.1E-14	0.00%	0.00
2014Q1	660.474	668.582	-8.10854	-1.23%	(0.37)
2014Q2	524.73	512.543	12.1879	2.32%	0.55
2014Q3	424.573	441.833	-17.2605	-4.07%	(0.78)
2014Q4	523.247	510.065	13.1811	2.52%	0.60
2015Q1	638.225	631.392	6.83313	1.07%	0.31
2015Q2	518.824	518.824	1.4E-14	0.00%	0.00
2015Q3	420.317	398.863	21.4539	5.10%	0.97
2015Q4	653.469	680.238	-26.7698	-4.10%	(1.22)
2016Q1	820.748	798.283	22.4647	2.74%	1.02
2016Q2	756.356	756.356	1.7E-13	0.00%	0.00
2016Q3	610.708	621.283	-10.5751	-1.73%	(0.48)
2016Q4	626.174	626.174	-8.5E-14	0.00%	0.00

2017Q1	775.263	809.568	-34.3054	-4.43%	(1.56)
2017Q2	693.127	695.178	-2.05086	-0.30%	(0.09)
2017Q3	591.754	621.861	-30.1062	-5.09%	(1.37)
2017Q4	649.543	685.044	-35.501	-5.47%	(1.61)
2018Q1	799.693	830.202	-30.5094	-3.82%	(1.39)
2018Q2	718.177	697.701	20.4761	2.85%	0.93
2018Q3	655.481	622.244	33.2363	5.07%	1.51
2018Q4	740.62	701.426	39.1938	5.29%	1.78
2019Q1	875.644	861.194	14.4493	1.65%	0.66
2019Q2	772.071	772.071	4.3E-14	0.00%	0.00
2019Q3	636.339	655.311	-18.9726	-2.98%	(0.86)
2019Q4	732.405	727.882	4.52322	0.62%	0.21
2020Q1	844.81	805.054	39.7562	4.71%	1.80
2020Q2	601.302	601.338	-0.03572	-0.01%	(0.00)
2020Q3	520.492	520.457	0.03572	0.01%	0.00
2020Q4	697.58	694.383	3.19773	0.46%	0.15
2021Q1	836.759	824.842	11.9171	1.42%	0.54
2021Q2	701.979	694.507	7.47204	1.06%	0.34
2021Q3	622.83	625.297	-2.46633	-0.40%	(0.11)
2021Q4	649.204	649.204	1.4E-13	0.00%	0.00
2022Q1	810.14	825.392	-15.252	-1.88%	(0.69)
2022Q2	703.06	696.609	6.45065	0.92%	0.29
2022Q3	629.836	626.464	3.37151	0.54%	0.15

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	649.2044	694.6784	-45.47	-7.0%
Q1 2022	810.1402	826.5432	-16.40	-2.0%
Q2 2022	703.0596	696.7861	6.27	0.9%
Q3 2022	629.8358	626.1093	3.73	0.6%
Total	2792.24	2844.12	-51.88	-1.9%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	449.0178	448.2986	0.7192	0%
S_HLFNGP_ST_ROLL12(-3)	-9.879969	-9.855737	-0.024232	0%
S_Q1_EDD+S_Q2_EDD	0.058975	0.05942	-0.000445	-1%
S_Q4_EDD	0.04155	0.041873	-0.000323	-1%
S_D15Q4_AFT	221.5921	221.8479	-0.2558	0%
S_D09Q1	-129.4447	-130.4906	1.0459	-1%
S_D20Q2+S_D20Q3	-103.6926	-103.6496	-0.043	0%
S_D16Q4	-64.76036	-64.95816	0.1978	0%
S_D19Q2	53.54405	53.77115	-0.2271	0%
S_D2014	43.94184	43.84099	0.10085	0%
S_D16Q2	66.85486	66.68105	0.17381	0%
S_D13Q2	63.84215	63.9025	-0.06035	0%
S_D13Q4	66.50999	66.5104	-0.00041	0%
S_D15Q2	52.33608	52.4201	-0.08402	0%
S_D07Q3	-86.94687	-86.22775	-0.71912	1%
S_D21Q4	-45.29095	0	-45.29095	100%
S_D2019	32.28058	31.92129	0.35929	1%

LLFC Sales Brockton
III. Sales - Customers
D. Low Load Factor Customers - Sales
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
B_LLF_CUST_SALES	13	0.977	6.946

ARIMA Model Parameters

B_LLF_CUST_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	10733.4	105.296	101.94	0.000
	B_GMP	4.090786	0.226	18.06	0.000
	Q3	-295.1351	22.098	-13.36	0.000
	B_D20Q2+B_D20Q3	237.4899	36.118	6.58	0.000
	B_D16Q1	252.1055	52.049	4.84	0.000
	B_D19Q4	-176.2833	50.571	-3.49	0.003
	B_D18Q2	-152.3673	50.397	-3.02	0.008
	B_D19Q1	229.1143	50.306	4.55	0.000
	B_D18Q1	188.7123	50.550	3.73	0.002
	B_D21Q4	-272.507	53.059	-5.14	0.000
	B_D22Q2	-125.5553	54.616	-2.30	0.035
	B_D16Q4	-166.052	51.499	-3.22	0.005
	B_D17Q2	-145.3335	51.314	-2.83	0.012

Variable	Definition	Explanation	Dummy Variable Support
B_GMP	Gross Metro Product (bil. $) in Brockton		
Q3	Binary variable equal to 1 in Q3	C	
B_D20Q2+B_D20Q3	Binary variable equal to 1 in 2020Q2 and 2020Q3		2
B_D16Q1	Binary variable equal to 1 in 2016Q1		2
B_D19Q4	Binary variable equal to 1 in 2019Q4		2
B_D18Q2	Binary variable equal to 1 in 2018Q2		2
B_D19Q1	Binary variable equal to 1 in 2019Q1		2
B_D18Q1	Binary variable equal to 1 in 2018Q1		2
B_D21Q4	Binary variable equal to 1 in 2021Q4		2
B_D22Q2	Binary variable equal to 1 in 2022Q2		2
B_D16Q4	Binary variable equal to 1 in 2016Q4		2
B_D17Q2	Binary variable equal to 1 in 2017Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

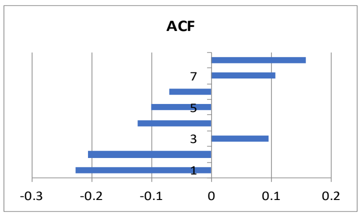
N	Adjusted R2	F Statistic
29	0.959919	56.8822

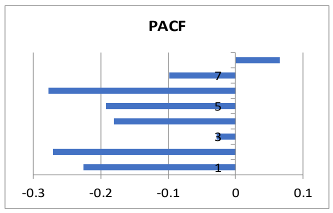
Chow Test Stats	N	k	SSR
Combined	29	13	37,239.01
1	14	8	2,373.65
2	15	8	17,718.70

Chow Stat:	0.197
P-Value:	0.984779

Heteroscedasticity - White's Test	
White Stat	0.84
Significance (p-value)	0.62

Correlations												
	B_GMP	Q3	B_D20Q2+B_D20Q3	B_D16Q1	B_D19Q4	B_D18Q2	B_D19Q1	B_D18Q1	B_D21Q4	B_D22Q2	B_D16Q4	B_D17Q2
B_GMP	1	0.036183	-0.047763	-0.230992	0.086442	-0.055133	-0.01205	-0.0877	0.286043	0.361175	-0.19109	-0.17568
Q3	0.036183	1	0.136487	-0.116642	-0.11664	-0.116642	-0.11664	-0.11664	-0.11664	-0.11664	-0.11664	-0.11664
B_D20Q2+B_D20Q3	-0.047763	0.136487	1	-0.051434	-0.05143	-0.051434	-0.05143	-0.05143	-0.05143	-0.05143	-0.05143	-0.05143
B_D16Q1	-0.230992	-0.116642	-0.051434	1	-0.03571	-0.035714	-0.03571	-0.03571	-0.03571	-0.03571	-0.03571	-0.03571
B_D19Q4	0.086442	-0.116642	-0.051434	-0.035714	1	-0.035714	-0.03571	-0.03571	-0.03571	-0.03571	-0.03571	-0.03571
B_D18Q2	-0.055133	-0.116642	-0.051434	-0.035714	-0.03571	1	-0.03571	-0.03571	-0.03571	-0.03571	-0.03571	-0.03571
B_D19Q1	-0.012051	-0.116642	-0.051434	-0.035714	-0.03571	-0.035714	1	-0.03571	-0.03571	-0.03571	-0.03571	-0.03571
B_D18Q1	-0.087703	-0.116642	-0.051434	-0.035714	-0.03571	-0.035714	-0.03571	1	-0.03571	-0.03571	-0.03571	-0.03571
B_D21Q4	0.286043	-0.116642	-0.051434	-0.035714	-0.03571	-0.035714	-0.03571	-0.03571	1	-0.03571	-0.03571	-0.03571
B_D22Q2	0.361175	-0.116642	-0.051434	-0.035714	-0.03571	-0.035714	-0.03571	-0.03571	-0.03571	1	-0.03571	-0.03571
B_D16Q4	-0.191091	-0.116642	-0.051434	-0.035714	-0.03571	-0.035714	-0.03571	-0.03571	-0.03571	-0.03571	1	-0.03571
B_D17Q2	-0.175682	-0.116642	-0.051434	-0.035714	-0.03571	-0.035714	-0.03571	-0.03571	-0.03571	-0.03571	-0.03571	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_llf_cust_sales Model	ACF	-0.226	-0.206	0.096	-0.124	-0.101	-0.071	0.106	0.158
	SE	0.371	0.371	0.371	0.371	0.371	0.371	0.371	0.371
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_llf_cust_sales Model		-0.226	-0.271	-0.028	-0.181	-0.193	-0.277	-0.099	0.066
	SE	0.371	0.371	0.371	0.371	0.371	0.371	0.371	0.371

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2015Q3	12017	12063.8	-46.7507	-0.39%	(0.97)
2015Q4	12373.7	12362.1	11.5438	0.09%	0.24
2016Q1	12628.3	12628.3	-1.8E-12	0.00%	(0.00)
2016Q2	12411.3	12396	15.3632	0.12%	0.32
2016Q3	12104	12117.6	-13.645	-0.11%	(0.28)
2016Q4	12252.3	12252.3	-2.9E-12	0.00%	(0.00)
2017Q1	12477	12429	48.0414	0.39%	1.00
2017Q2	12289.3	12289.3	-1.4E-12	0.00%	(0.00)
2017Q3	12147.3	12163	-15.6794	-0.13%	(0.33)
2017Q4	12524.3	12495.9	28.3835	0.23%	0.59
2018Q1	12716.3	12716.3	-2.1E-12	0.00%	(0.00)
2018Q2	12409.7	12409.7	-3.1E-12	0.00%	(0.00)
2018Q3	12227	12281.3	-54.2899	-0.44%	(1.13)
2018Q4	12634.7	12588.7	45.9492	0.36%	0.95
2019Q1	12836.7	12836.7	-1.4E-12	0.00%	(0.00)
2019Q2	12596.3	12635.8	-39.4225	-0.31%	(0.82)
2019Q3	12396.3	12373.2	23.0974	0.19%	0.48
2019Q4	12535.3	12535.3	-1.6E-12	0.00%	(0.00)
2020Q1	12691.7	12721.8	-30.1755	-0.24%	(0.63)
2020Q2	12697.3	12721.2	-23.8943	-0.19%	(0.50)
2020Q3	12653	12629.1	23.8943	0.19%	0.50
2020Q4	12703.7	12711.9	-8.23324	-0.06%	(0.17)
2021Q1	12846.7	12764.1	82.5462	0.64%	1.71
2021Q2	12792.7	12818.4	-25.7455	-0.20%	(0.53)
2021Q3	12592	12554.1	37.8517	0.30%	0.78
2021Q4	12650	12650	-2.8E-13	0.00%	(0.00)
2022Q1	12858	12962.4	-104.356	-0.81%	(2.16)
2022Q2	12876.3	12876.3	-2.8E-12	0.00%	(0.00)
2022Q3	12795.7	12750.1	45.5216	0.36%	0.94

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	12650	12946.38	-296.38	-2.3%
Q1 2022	12858	12987.9	-129.90	-1.0%
Q2 2022	12876.33	13029.08	-152.75	-1.2%
Q3 2022	12795.67	12763.67	32.00	0.3%
Total	51180.00	51727.03	-547.03	-1.1%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	10733.4	10665.83	67.57	1%
B_GMP	4.090786	4.261681	-0.170895	-4%
Q3	-295.1351	-310.6199	15.4848	-5%
B_D20Q2+B_D20Q3	237.4899	235.4448	2.0451	1%
B_D16Q1	252.1055	251.0498	1.0557	0%
B_D19Q4	-176.2833	-191.3502	15.0669	-9%
B_D18Q2	-152.3673	-161.1852	8.8179	-6%
B_D19Q1	229.1143	218.3948	10.7195	5%
B_D18Q1	188.7123	181.332	7.3803	4%
B_D21Q4	-272.507	0	-272.507	100%
B_D22Q2	-125.5553	0	-125.5553	100%
B_D16Q4	-166.052	-168.8689	2.8169	-2%
B_D17Q2	-145.3335	-148.8305	3.497	-2%

LLFC Sales Lawrence
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
L_LLF_CUST_SALES	7	0.865	7.132

ARIMA Model Parameters

L_LLF_CUST_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	1796.973	211.622	8.49	0.000
	L_LLFNGP_S_ROLL12(-2)	-18.59477	7.516	-2.47	0.018
	L_PINC	0.010921	0.001	7.39	0.000
	L_D18Q3	-238.8825	55.167	-4.33	0.000
	L_D18Q4	-158.686	53.892	-2.94	0.005
	Q1	77.27654	17.842	4.33	0.000
	L_D12Q3	-102.4676	52.300	-1.96	0.057

Variable	Definition	Explanation	Dummy Variable Support
L_LLFNGP_S_ROLL12(-2)	Rolling 12 quarter natural gas price for low load factor customers in Lawrence ($2022) lagged two quarters		
L_PINC	Total personal income in Lawrence (million $2012)		
L_D18Q3	Binary variable equal to 1 in 2018Q3		2
L_D18Q4	Binary variable equal to 1 in 2018Q4		2
Q1	Binary variable equal to 1 in Q1	C	
L_D12Q3	Binary variable equal to 1 in 2012Q3		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
46	0.844522	41.73849

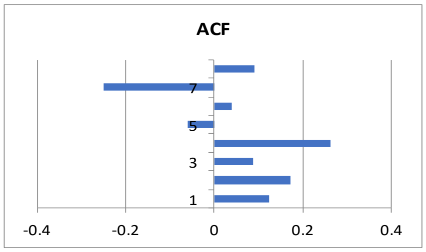
Chow Test Stats	N	k	SSR
Combined	46	7	100,894.34
1	25	5	36,316.12
2	21	6	30,848.48

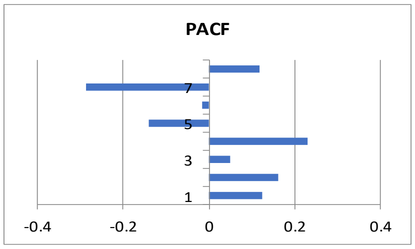
Chow Stat:	2.296
P-Value:	0.051495

Heteroscedasticity - White's Test	
White Stat	1.05
Significance (p-value)	0.41

Correlations

	L_LLFNGP_S_ROLL12(-2)	L_PINC	L_D18Q3	L_D18Q4	Q1	L_D12Q3
L_LLFNGP_S_ROLL12(-2)	1	-0.70294	-0.242299	-0.203562	-0.0406	0.10936
L_PINC	-0.70294	1	0.012969	0.032279	0.036488	-0.159081
L_D18Q3	-0.242299	0.012969	1	-0.022222	-0.08357	-0.022222
L_D18Q4	-0.203562	0.032279	-0.022222	1	-0.08357	-0.022222
Q1	-0.040596	0.036488	-0.083571	-0.083571	1	-0.083571
L_D12Q3	0.10936	-0.159081	-0.022222	-0.022222	-0.08357	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_llf_cust_sales	ACF	0.124	0.174	0.087	0.263	-0.06	0.04	-0.251	0.091
	SE	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_llf_cust_sales		0.124	0.161	0.051	0.232	-0.14	-0.016	-0.288	0.118
	SE	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2011Q2	2228.67	2250	-21.3359	-0.96%	(0.42)
2011Q3	2196.33	2251.47	-55.1396	-2.51%	(1.08)
2011Q4	2280.33	2259.3	21.0323	0.92%	0.41
2012Q1	2348.33	2359.84	-11.5077	-0.49%	(0.23)
2012Q2	2257	2293.54	-36.5419	-1.62%	(0.72)
2012Q3	2194.33	2194.33	-1.6E-13	0.00%	0.00
2012Q4	2244.33	2314.74	-70.4069	-3.14%	(1.38)
2013Q1	2312	2368.85	-56.8482	-2.46%	(1.12)
2013Q2	2237.33	2294.79	-57.4601	-2.57%	(1.13)
2013Q3	2214	2297.66	-83.6562	-3.78%	(1.64)
2013Q4	2331.67	2297.99	33.6718	1.44%	0.66
2014Q1	2412.67	2382.75	29.9163	1.24%	0.59
2014Q2	2317	2311.92	5.07518	0.22%	0.10
2014Q3	2255.33	2319.8	-64.4675	-2.86%	(1.27)
2014Q4	2385.67	2329.96	55.7096	2.34%	1.10
2015Q1	2477.33	2417.28	60.0572	2.42%	1.18
2015Q2	2370.67	2339.09	31.5801	1.33%	0.62
2015Q3	2306	2338.39	-32.3884	-1.40%	(0.64)
2015Q4	2442.33	2347.63	94.7037	3.88%	1.86
2016Q1	2510.33	2421.69	88.6426	3.53%	1.74
2016Q2	2449.67	2354.52	95.1499	3.88%	1.87
2016Q3	2363.67	2369.35	-5.68721	-0.24%	(0.11)
2016Q4	2404	2378.97	25.0261	1.04%	0.49
2017Q1	2463.67	2467.8	-4.13739	-0.17%	(0.08)
2017Q2	2412.67	2403.96	8.70634	0.36%	0.17
2017Q3	2351.33	2423.01	-71.6718	-3.05%	(1.41)
2017Q4	2450.67	2436.32	14.3437	0.59%	0.28
2018Q1	2519.33	2521.41	-2.07277	-0.08%	(0.04)
2018Q2	2432.33	2451.45	-19.1209	-0.79%	(0.38)
2018Q3	2220.67	2220.67	-1.7E-13	0.00%	0.00
2018Q4	2304	2304			
2019Q1	2567	2567.15	-0.1516	-0.01%	(0.00)
2019Q2	2542.33	2487.94	54.3928	2.14%	1.07
2019Q3	2482	2480.04	1.95719	0.08%	0.04
2019Q4	2522.67	2476.23	46.4405	1.84%	0.91
2020Q1	2569.33	2561.71	7.61852	0.30%	0.15
2020Q2	2579	2601.63	-22.6282	-0.88%	(0.44)
2020Q3	2577.33	2548.85	28.4882	1.11%	0.56
2020Q4	2572.67	2518.51	54.1583	2.11%	1.06
2021Q1	2606.67	2712.7	-106.038	-4.07%	(2.08)
2021Q2	2592	2567.97	24.033	0.93%	0.47
2021Q3	2484.67	2549.67	-65.0018	-2.62%	(1.28)
2021Q4	2525.67	2538.52	-12.853	-0.51%	(0.25)
2022Q1	2606	2611.48	-5.47898	-0.21%	(0.11)
2022Q2	2586	2530.89	55.1146	2.13%	1.08
2022Q3	2497.67	2528.89	-31.224	-1.25%	(0.61)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	2525.667	2537.835	-12.17	-0.5%
Q1 2022	2606	2611.729	-5.73	-0.2%
Q2 2022	2586	2530.182	55.82	2.2%
Q3 2022	2497.667	2528.191	-30.52	-1.2%
Total	10215.33	10207.94	7.40	0.1%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	1796.973	1794.247	2.726	0%
L_LLFNGP_S_ROLL12(-2)	-18.59477	-18.43239	-0.16238	1%
L_PINC	0.010921	0.01092	1E-06	0%
L_D18Q3	-238.8825	-238.0387	-0.8438	0%
L_D18Q4	-158.686	-157.9072	-0.7788	0%
Q1	77.27654	78.25	-0.97346	-1%
L_D12Q3	-102.4676	-102.2219	-0.2457	0%

LLFC Sales Springfield
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
S_LLF_CUST_SALES	9	0.838	8.711

ARIMA Model Parameters

S_LLF_CUST_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	6064.029	177.361	34.19	0.000
	S_GMP	17.89841	4.699	3.81	0.001
	S_D2020+S_D21Q1	143.9107	37.944	3.79	0.001
	S_D17Q3+S_D17Q2	-168.4464	57.414	-2.93	0.007
	S_D18Q3	-225.6263	77.799	-2.90	0.008
	S_D19Q1	204.4151	77.753	2.63	0.015
	S_D16Q1	154.6042	79.665	1.94	0.064
	S_D15Q3+S_D15Q2	-190.8807	58.967	-3.24	0.004
	S_D14Q3	-374.183	81.236	-4.61	0.000

Variable	Definition	Explanation	Dummy Variable Support
S_GMP	Gross Metro Product (bil. $) in Springfield		
S_D2020+S_D21Q1	Binary variable equal to 1 in 2020Q2 and 2020Q3		2
S_D17Q3+S_D17Q2	Binary variable equal to 1 in 2017Q3 and 2017Q2		2
S_D18Q3	Binary variable equal to 1 in 2018Q3		2
S_D19Q1	Binary variable equal to 1 in 2019Q1		2
S_D16Q1	Binary variable equal to 1 in 2016Q1		2
S_D15Q3+S_D15Q2	Binary variable equal to 1 in 2015Q3 and 2015Q2		2
S_D14Q3	Binary variable equal to 1 in 2014Q3		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
33	0.783953	15.51446

Chow Test Stats

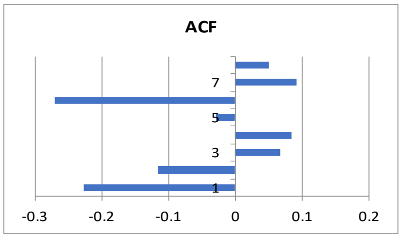
	N	k	SSR
Combined	33	9	138,183.44
1	18	7	56,832.41
2	15	4	54,271.42

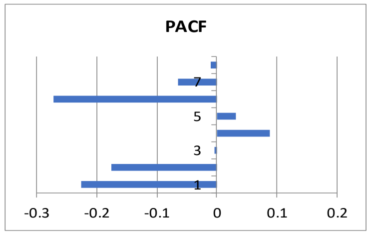
Chow Stat:	0.406
P-Value:	0.912525

Heteroscedasticity - White's Test	
White Stat	0.93
Significance (p-value)	0.51

Correlations

	S_GMP	S_D2020+S_D21Q1	S_D17Q3+S_D17Q2	S_D18Q3	S_D19Q1	S_D16Q1	S_D15Q3+S_D15Q2	S_D14Q3
S_GMP	1	0.073851	-0.141594	0.005926	0.037282	-0.170074	-0.248962	-0.24421
S_D2020+S_D21Q1	0.073851	1	-0.107335	-0.074702	-0.0747	-0.074702	-0.107335	-0.0747
S_D17Q3+S_D17Q2	-0.141594	-0.107335	1	-0.044901	-0.0449	-0.044901	-0.064516	-0.0449
S_D18Q3	0.005926	-0.074702	-0.044901	1	-0.03125	-0.03125	-0.044901	-0.03125
S_D19Q1	0.037282	-0.074702	-0.044901	-0.03125	1	-0.03125	-0.044901	-0.03125
S_D16Q1	-0.170074	-0.074702	-0.044901	-0.03125	-0.03125	1	-0.044901	-0.03125
S_D15Q3+S_D15Q2	-0.248962	-0.107335	-0.064516	-0.044901	-0.0449	-0.044901	1	-0.0449
S_D14Q3	-0.244212	-0.074702	-0.044901	-0.03125	-0.03125	-0.03125	-0.044901	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_llf_cust_sales Model	ACF	-0.226	-0.115	0.067	0.085	-0.028	-0.27	0.091	0.051
	SE	0.348	0.348	0.348	0.348	0.348	0.348	0.348	0.348
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_llf_cust_sales Model		-0.226	-0.175	-0.003	0.089	0.031	-0.271	-0.065	-0.011
	SE	0.348	0.348	0.348	0.348	0.348	0.348	0.348	0.348

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2014Q3	6272.67	6272.67	1.3E-12	0.00%	(0.00)
2014Q4	6550.67	6649.47	-98.7994	-1.51%	(1.30)
2015Q1	6709.33	6656.63	52.7012	0.79%	0.69
2015Q2	6545.67	6477.45	68.2163	1.04%	0.90
2015Q3	6411.33	6479.55	-68.2163	-1.06%	(0.90)
2015Q4	6675.33	6670.04	5.28931	0.08%	0.07
2016Q1	6825	6825	1.1E-12	0.00%	(0.00)
2016Q2	6778.33	6672.42	105.915	1.56%	1.40
2016Q3	6656.33	6680.96	-24.6264	-0.37%	(0.32)
2016Q4	6658.33	6684.52	-26.1833	-0.39%	(0.35)
2017Q1	6671	6684.5	-13.4984	-0.20%	(0.18)
2017Q2	6577	6520.64	56.3619	0.86%	0.74
2017Q3	6472.33	6528.7	-56.3619	-0.87%	(0.74)
2017Q4	6641.67	6705.68	-64.0083	-0.96%	(0.84)
2018Q1	6751.33	6708.85	42.4797	0.63%	0.56
2018Q2	6587	6718.23	-131.232	-1.99%	(1.73)
2018Q3	6500.67	6500.67	1.9E-12	0.00%	(0.00)
2018Q4	6683.33	6730.07	-46.7366	-0.70%	(0.62)
2019Q1	6940.67	6940.67	2.4E-12	0.00%	(0.00)
2019Q2	6845	6745.89	99.1062	1.45%	1.31
2019Q3	6690.67	6752.67	-62.0028	-0.93%	(0.82)
2019Q4	6837.67	6760.43	77.2382	1.13%	1.02
2020Q1	6881.67	6901.82	-20.1574	-0.29%	(0.27)
2020Q2	6877.67	6814.02	63.649	0.93%	0.84
2020Q3	6858.67	6877.88	-19.2105	-0.28%	(0.25)
2020Q4	6865.67	6891.67	-26.0064	-0.38%	(0.34)
2021Q1	6907	6905.27	1.72528	0.02%	0.02
2021Q2	6879.33	6781.03	98.2999	1.43%	1.30
2021Q3	6773.67	6794.74	-21.0687	-0.31%	(0.28)
2021Q4	6837.33	6811.74	25.5916	0.37%	0.34
2022Q1	6944.33	6826.68	117.657	1.69%	1.55
2022Q2	6853.33	6840.93	12.4039	0.18%	0.16
2022Q3	6705.67	6854.19	-148.526	-2.21%	(1.96)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	6837.333	6821.018	16.31	0.2%
Q1 2022	6944.333	6837.412	106.92	1.5%
Q2 2022	6853.333	6853.058	0.27	0.0%
Q3 2022	6705.667	6867.618	-161.95	-2.4%
Total	27340.67	27379.11	-38.44	-0.1%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	6064.029	6000.235	63.794	1%
S_GMP	17.89841	19.64752	-1.74911	-9.8%
S_D2020+S_D21Q1	143.9107	142.2096	1.7011	1%
S_D17Q3+S_D17Q2	-168.4464	-166.13	-2.3164	1%
S_D18Q3	-225.6263	-226.5525	0.9262	0%
S_D19Q1	204.4151	202.5158	1.8993	1%
S_D16Q1	154.6042	159.1406	-4.5364	-3%
S_D15Q3+S_D15Q2	-190.8807	-186.2451	-4.6356	2%
S_D14Q3	-374.183	-367.3456	-6.8374	2%

HLFC Sales Brockton
A. High Load Factor Customers - Sales
1. Brockton

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
B_HLF_CUST_SALES	7	0.820	7.463

ARIMA Model Parameters

B_HLF_CUST_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	2495.261	62.341	40.03	0.000
	B_HLFNGP_S_ROLL12	-23.3779	5.335	-4.38	0.000
	B_D12Q4	234.8528	56.999	4.12	0.000
	B_D14Q4_D16Q3	-221.2184	23.009	-9.61	0.000
	B_D18Q2_D19Q3	-191.1261	29.926	-6.39	0.000
	B_D19Q4_D21Q4	-99.37712	24.953	-3.98	0.000
	B_D2013	146.0439	30.323	4.82	0.000

Variable	Definition	Explanation	Dummy Variable Support
B_HLFNGP_S_ROLL12	Rolling 12 quarter natural gas price for high load factor customers in Brockton ($2022)		
B_D12Q4	Binary variable equal to 1 in 2012Q4		2
B_D14Q4_D16Q3	Binary variable equal to 1 from 2014Q4 to 2016Q3		2
B_D18Q2_D19Q3	Binary variable equal to 1 in 2018Q2 to 2019Q3		2
B_D19Q4_D21Q4	Binary variable equal to 1 in 2019Q4 to 2021Q4		2
B_D2013	Binary variable equal to 1 in 2013		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

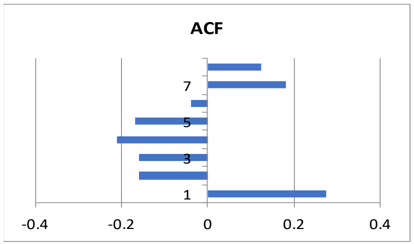
N	Adjusted R2	F Statistic
50	0.794696	32.61167

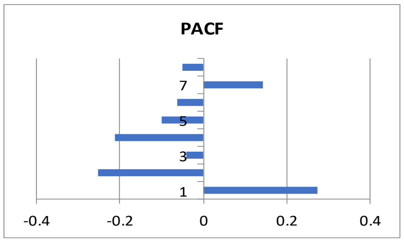
Chow Test Stats	N	k	SSR
Combined	50	7	133,370.06
1	25	5	64,966.83
2	25	5	42,184.09

Chow Stat:	1.258
P-Value:	0.298109

Heteroscedasticity - White's Test	
White Stat	1.81
Significance (p-value)	0.12

Correlations	B_HLFNGP_S_ROLL12	B_D12Q4	B_D14Q4_D16Q3	B_D18Q2_D19Q3	B_D19Q4_D21Q4	B_D2013
B_HLFNGP_S_ROLL12	1	0.086431	0.192856	-0.429761	-0.373677	0.156972
B_D12Q4	0.086431	1	-0.062348	-0.052753	-0.066932	-0.042126
B_D14Q4_D16Q3	0.192856	-0.062348	1	-0.161165	-0.204479	-0.128698
B_D18Q2_D19Q3	-0.429761	-0.052753	-0.161165	1	-0.173013	-0.108893
B_D19Q4_D21Q4	-0.373677	-0.066932	-0.204479	-0.173013	1	-0.138159
B_D2013	0.156972	-0.042126	-0.128698	-0.108893	-0.138159	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_hlf_cust_sales Model	ACF	0.274	-0.159	-0.16	-0.211	-0.168	-0.039	0.182	0.125
	SE	0.283	0.283	0.283	0.283	0.283	0.283	0.283	0.283
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_hlf_cust_sales Model		0.274	-0.253	-0.041	-0.213	-0.1	-0.061	0.143	-0.051
	SE	0.283	0.283	0.283	0.283	0.283	0.283	0.283	0.283

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2010Q2	2144.67	2148.8	-4.13116	-0.19%	(0.07)
2010Q3	2152.67	2152.59	0.0746	0.00%	0.00
2010Q4	2233.33	2154.96	78.3754	3.51%	1.41
2011Q1	2234	2160.27	73.7283	3.30%	1.32
2011Q2	2205.67	2171.8	33.8626	1.54%	0.61
2011Q3	2172.67	2189.44	-16.7783	-0.77%	(0.30)
2011Q4	2162	2198.22	-36.2164	-1.68%	(0.65)
2012Q1	2157	2208.04	-51.0398	-2.37%	(0.92)
2012Q2	2114.33	2214.53	-100.194	-4.74%	(1.80)
2012Q3	2205.67	2215.11	-9.44492	-0.43%	(0.17)
2012Q4	2451	2451	1.7E-13	0.00%	(0.00)
2013Q1	2453.67	2366.57	87.0969	3.55%	1.56
2013Q2	2427	2364.05	62.948	2.59%	1.13
2013Q3	2350.33	2364.42	-14.088	-0.60%	(0.25)
2013Q4	2230.67	2366.62	-135.957	-6.09%	(2.44)
2014Q1	2253	2219.7	33.2993	1.48%	0.60
2014Q2	2187.33	2213.11	-25.7724	-1.18%	(0.46)
2014Q3	2093	2214.42	-121.424	-5.80%	(2.18)
2014Q4	2043	1992.19	50.8134	2.49%	0.91
2015Q1	2041	1987.34	53.6573	2.63%	0.96
2015Q2	2005.67	1988.93	16.7366	0.83%	0.30
2015Q3	1948	1993	-45.0002	-2.31%	(0.81)
2015Q4	1947.33	1999.38	-52.0443	-2.67%	(0.93)
2016Q1	1989	2006.77	-17.7698	-0.89%	(0.32)
2016Q2	1971.33	2019.74	-48.4018	-2.46%	(0.87)
2016Q3	2072	2029.99	42.009	2.03%	0.75
2016Q4	2317.33	2259.38	57.9534	2.50%	1.04
2017Q1	2343.33	2270.12	73.2089	3.12%	1.31
2017Q2	2335.33	2289.16	46.1699	1.98%	0.83
2017Q3	2301.33	2296.61	4.72171	0.21%	0.08
2017Q4	2295.67	2304.66	-8.9893	-0.39%	(0.16)
2018Q1	2295	2308.99	-13.9902	-0.61%	(0.25)
2018Q2	2241	2112.62	128.382	5.73%	2.31
2018Q3	2153.33	2112.62	40.7105	1.89%	0.73
2018Q4	2038	2108.87	-70.8683	-3.48%	(1.27)
2019Q1	2053.67	2101.63	-47.9592	-2.34%	(0.86)
2019Q2	2046.67	2093.69	-47.0224	-2.30%	(0.84)
2019Q3	2088.33	2091.58	-3.24238	-0.16%	(0.06)
2019Q4	2177	2182.04	-5.03653	-0.23%	(0.09)
2020Q1	2155.33	2180.87	-25.5413	-1.19%	(0.46)
2020Q2	2152.67	2175.86	-23.1887	-1.08%	(0.42)
2020Q3	2166	2174.93	-8.92965	-0.41%	(0.16)
2020Q4	2170.33	2174.55	-4.21759	-0.19%	(0.08)
2021Q1	2184	2179.43	4.56777	0.21%	0.08
2021Q2	2175	2185.17	-10.1692	-0.47%	(0.18)
2021Q3	2189.67	2181.19	8.47875	0.39%	0.15
2021Q4	2241	2176.96	64.0365	2.86%	1.15
2022Q1	2262.33	2275.92	-13.5888	-0.60%	(0.24)
2022Q2	2265.67	2269.39	-3.72607	-0.16%	(0.07)
2022Q3	2264.33	2260.43	3.90135	0.17%	0.07

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	2241	2168.919	72.08	3.2%
Q1 2022	2262.333	2277.588	-15.26	-0.7%
Q2 2022	2265.667	2270.945	-5.28	-0.2%
Q3 2022	2264.333	2261.829	2.50	0.1%
Total	9033.33	8979.28	54.05	0.6%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	2495.261	2500.726	-5.465	0%
B_HLFNGP_S_ROLL12	-23.3779	-23.78288	0.40498	-2%
B_D12Q4	234.8528	234.2226	0.6302	0%
B_D14Q4_D16Q3	-221.2184	-221.9739	0.7555	0%
B_D18Q2_D19Q3	-191.1261	-193.1158	1.9897	-1%
B_D19Q4_D21Q4	-99.37712	-109.0943	9.71718	-10%
B_D2013	146.0439	145.3578	0.6861	0%

HLFC Sales Lawrence
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
L_HLF_CUST_SALES	8	0.860	3.309

ARIMA Model Parameters

L_HLF_CUST_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	685.0322	51.870	13.21	0.000
	L_HLFNGP_S_ROLL12(-2)	-8.940333	4.953	-1.81	0.079
	L_D15Q2_D16Q3	-32.22722	8.430	-3.82	0.001
	L_D12Q2	-18.10863	8.424	-2.15	0.038
	L_D12Q4	25.6424	9.800	2.62	0.013
	L_D18Q3+L_D18Q4	-57.58323	8.535	-6.75	0.000
	L_D13Q1	17.37672	9.774	1.78	0.083
	AR(1)	0.832079	0.092	9.06	0.000

Variable	Definition	Explanation	Dummy Variable Support
L_HLFNGP_S_ROLL12(-2)	Rolling 12 quarter natural gas price for high load factor sales customers in Lawrence ($2022) lagged two quarters		
L_D15Q2_D16Q3	Binary variable equal to 1 from 2015Q2 to 2016Q3		2
L_D12Q2	Binary variable equal to 1 in 2012Q2		2
L_D12Q4	Binary variable equal to 1 in 2012Q4		2
L_D18Q3+L_D18Q4	Binary variable equal to 1 in 2018Q3 and 2018Q4		2
L_D13Q1	Binary variable equal to 1 in 2013Q1		2
AR(1)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
48	0.835053	34.99149

Chow Test Stats

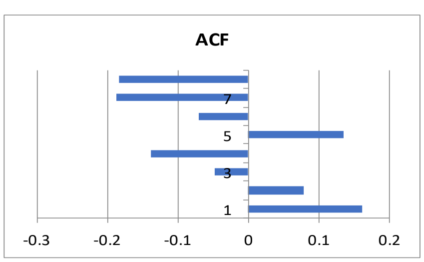
		N	k	SSR
Combined		48	8	4,796.02
	1	21	7	1,271.98
	2	27	5	2,637.55

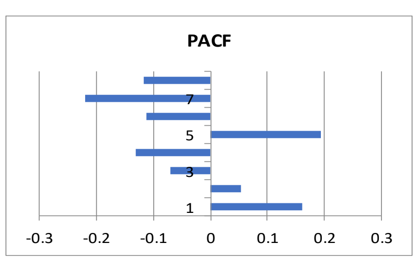
Chow Stat:	0.907
P-Value:	0.522902

Heteroscedasticity - White's Test	
White Stat	1.90
Significance (p-value)	0.10

Correlations

	L_HLFNGP_S_ROLL12(-2)	L_D15Q2_D16Q3	L_D12Q2	L_D12Q4	L_D18Q3+L_D18Q4	L_D13Q1
L_HLFNGP_S_ROLL12(-2)	1	0.210512	0.142881	0.087044	-0.291846	0.080857
L_D15Q2_D16Q3	0.210512	1	-0.055132	-0.055132	-0.078811	-0.055132
L_D12Q2	0.142881	-0.055132	1	-0.021277	-0.030415	-0.021277
L_D12Q4	0.087044	-0.055132	-0.021277	1	-0.030415	-0.021277
L_D18Q3+L_D18Q4	-0.291846	-0.078811	-0.030415	-0.030415	1	-0.030415
L_D13Q1	0.080857	-0.055132	-0.021277	-0.021277	-0.030415	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_hlf_cust_sales Model	ACF	0.162	0.078	-0.048	-0.139	0.135	-0.07	-0.188	-0.183
	SE	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_hlf_cust_sales Model		0.162	0.053	-0.07	-0.13	0.193	-0.113	-0.22	-0.117
	SE	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2010Q4	569.667	559.952	9.71427	1.71%	0.89
2011Q1	567.333	568.231	-0.89807	-0.16%	(0.08)
2011Q2	555.667	565.924	-10.2576	-1.85%	(0.94)
2011Q3	549.333	557.335	-8.0018	-1.46%	(0.73)
2011Q4	550	554.86	-4.86049	-0.88%	(0.44)
2012Q1	553.333	558.878	-5.54454	-1.00%	(0.51)
2012Q2	537.333	541.072	-3.73857	-0.70%	(0.34)
2012Q3	557.333	561.826	-4.49297	-0.81%	(0.41)
2012Q4	599.333	588.532	10.801	1.80%	0.99
2013Q1	605.333	592.353	12.9805	2.14%	1.19
2013Q2	602.333	586.734	15.5998	2.59%	1.42
2013Q3	598	600.11	-2.11018	-0.35%	(0.19)
2013Q4	593.667	594.421	-0.75449	-0.13%	(0.07)
2014Q1	600.667	591.58	9.0869	1.51%	0.83
2014Q2	591.667	597.901	-6.23406	-1.05%	(0.57)
2014Q3	582	589.557	-7.55661	-1.30%	(0.69)
2014Q4	579	578.893	0.10709	0.02%	0.01
2015Q1	575	578.97	-3.97019	-0.69%	(0.36)
2015Q2	563.667	542.685	20.9817	3.72%	1.92
2015Q3	548	558.616	-10.6163	-1.94%	(0.97)
2015Q4	544	547.705	-3.70501	-0.68%	(0.34)
2016Q1	548.667	545.184	3.48302	0.63%	0.32
2016Q2	540.333	550.081	-9.74727	-1.80%	(0.89)
2016Q3	565.667	544.11	21.5564	3.81%	1.97
2016Q4	625.333	599.922	25.4115	4.06%	2.32
2017Q1	637.667	622.503	15.1634	2.38%	1.38
2017Q2	632.333	632.764	-0.43019	-0.07%	(0.04)
2017Q3	625.667	629.817	-4.15032	-0.66%	(0.38)
2017Q4	627	628.115	-1.11533	-0.18%	(0.10)
2018Q1	628.667	626.042	2.62456	0.42%	0.24
2018Q2	622	628.205	-6.20489	-1.00%	(0.57)
2018Q3	568.667	564.321	4.34599	0.76%	0.40
2018Q4	531.667	564.318	-32.6516	-6.14%	(2.98)
2019Q1	591.667	593.032	-1.36577	-0.23%	(0.12)
2019Q2	584.333	593.824	-9.4903	-1.62%	(0.87)
2019Q3	580.667	585.98	-5.31325	-0.92%	(0.49)
2019Q4	586	581.959	4.04148	0.69%	0.37
2020Q1	579	588.088	-9.0876	-1.57%	(0.83)
2020Q2	577	582.351	-5.35146	-0.93%	(0.49)
2020Q3	582.667	580.647	2.01954	0.35%	0.18
2020Q4	596.333	583.922	12.4109	2.08%	1.13
2021Q1	595.333	596.58	-1.24715	-0.21%	(0.11)
2021Q2	592	595.778	-3.77824	-0.64%	(0.35)
2021Q3	591	594.994	-3.99402	-0.68%	(0.36)
2021Q4	596	594.857	1.14309	0.19%	0.10
2022Q1	601	595.647	5.35284	0.89%	0.49
2022Q2	598.333	599.357	-1.02317	-0.17%	(0.09)
2022Q3	589.333	598.466	-9.13258	-1.55%	(0.83)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	596	598.3946	-2.39	-0.4%
Q1 2022	601	597.7065	3.29	0.5%
Q2 2022	598.3333	596.6772	1.66	0.3%
Q3 2022	589.3333	597.1745	-7.84	-1.3%
Total	2384.67	2389.95	-5.29	-0.2%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	685.0322	687.1334	-2.1012	0%
L_HLFNGP_S_ROLL12(-2)	-8.940333	-9.099425	0.159092	-2%
L_D15Q2_D16Q3	-32.22722	-32.22067	-0.00655	0%
L_D12Q2	-18.10863	-18.09886	-0.00977	0%
L_D12Q4	25.6424	25.61116	0.03124	0%
L_D18Q3+L_D18Q4	-57.58323	-57.61817	0.03494	0%
L_D13Q1	17.37672	17.35059	0.02613	0%
AR(1)	0.832079	0.834615	-0.002536	0%

HLFC Sales Springfield
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
S_HLF_CUST_SALES	5	0.797	4.980

ARIMA Model Parameters

S_HLF_CUST_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	1471.081	41.544	35.41	0.000
	S_HLFNGP_S_ROLL12(-2)	-8.390939	3.309	-2.54	0.014
	S_D14Q3_D16Q3	-95.57161	16.582	-5.76	0.000
	S_D18Q3_D21Q3	-60.94486	16.318	-3.73	0.001
	AR(1)	0.581701	0.119	4.88	0.000

Variable	Definition	Explanation	Dummy Variable Support
S_HLFNGP_S_ROLL12(-2)	Rolling 12 quarter natural gas price for high load factor customers in Springfield ($2022) lagged two quarters		
S_D14Q3_D16Q3	Binary variable equal to 1 from 2014Q3 to 2016Q3		2
S_D18Q3_D21Q3	Binary variable equal to 1 from 2018Q3 to 2021Q3		2
AR(1)			

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

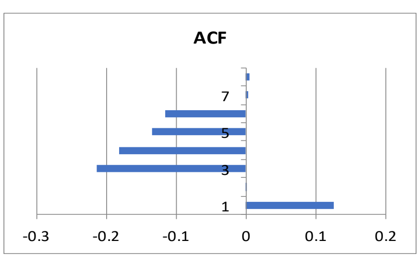
N	Adjusted R2	F Statistic
55	0.780617	49.03625

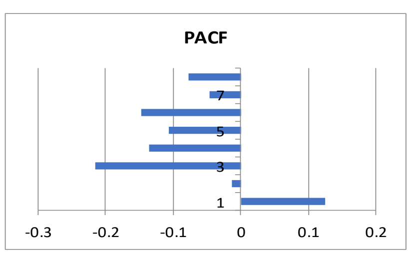
Chow Test Stats	N	k	SSR
Combined	55	5	30,743.66
1	27	4	19,191.67
2	28	5	8,616.49

Chow Stat:	0.95
P-Value:	0.458335

Heteroscedasticity - White's Test	
White Stat	49.04
Significance (p-value)	0.21

Correlations	S_HLFNGP_S_ROLL12(-2)	S_D14Q3_D16Q3	S_D18Q3_D21Q3
S_HLFNGP_S_ROLL12(-2)	1	0.022541	-0.551667
S_D14Q3_D16Q3	0.022541	1	-0.246087
S_D18Q3_D21Q3	-0.551667	-0.246087	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_hlf_cust_sales Model	ACF	0.126	0.002	-0.213	-0.181	-0.135	-0.116	0.003	0.005
	SE	0.270	0.270	0.270	0.270	0.270	0.270	0.270	0.270
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_hlf_cust_sales Model		0.126	-0.014	-0.215	-0.136	-0.106	-0.148	-0.047	-0.078
	SE	0.270	0.270	0.270	0.270	0.270	0.270	0.270	0.270

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2009Q1	1356.67	1337.78	18.8863	1.39%	0.76
2009Q2	1317	1341.77	-24.7665	-1.88%	(1.00)
2009Q3	1314	1320.79	-6.78793	-0.52%	(0.27)
2009Q4	1330.67	1320.86	9.80308	0.74%	0.40
2010Q1	1342.33	1333.6	8.73805	0.65%	0.35
2010Q2	1322	1341.28	-19.2754	-1.46%	(0.78)
2010Q3	1320.33	1329.88	-9.54978	-0.72%	(0.39)
2010Q4	1359	1330.76	28.2359	2.08%	1.14
2011Q1	1379.67	1352.8	26.8663	1.95%	1.08
2011Q2	1350.67	1365.05	-14.3848	-1.07%	(0.58)
2011Q3	1324.33	1349.54	-25.2105	-1.90%	(1.02)
2011Q4	1318.33	1337.58	-19.2502	-1.46%	(0.78)
2012Q1	1308.67	1338.25	-29.5827	-2.26%	(1.19)
2012Q2	1292.33	1331.99	-39.652	-3.07%	(1.60)
2012Q3	1330.33	1324.04	6.28969	0.47%	0.25
2012Q4	1419.67	1346.62	73.0476	5.15%	2.95
2013Q1	1432.33	1397.68	34.6554	2.42%	1.40
2013Q2	1426.67	1405.37	21.2977	1.49%	0.86
2013Q3	1411	1403.8	7.1992	0.51%	0.29
2013Q4	1373.67	1393.53	-19.8599	-1.45%	(0.80)
2014Q1	1376	1372.43	3.57314	0.26%	0.14
2014Q2	1360.33	1374.69	-14.3566	-1.06%	(0.58)
2014Q3	1317.67	1268.97	48.6989	3.70%	1.96
2014Q4	1254.33	1297.46	-43.1242	-3.44%	(1.74)
2015Q1	1273.67	1262.1	11.5643	0.91%	0.47
2015Q2	1255	1272.85	-17.8512	-1.42%	(0.72)
2015Q3	1241	1260.68	-19.6797	-1.59%	(0.79)
2015Q4	1246	1253.88	-7.88354	-0.63%	(0.32)
2016Q1	1238.67	1257.67	-19.0047	-1.53%	(0.77)
2016Q2	1232.67	1254.75	-22.0816	-1.79%	(0.89)
2016Q3	1303.67	1252.43	51.2386	3.93%	2.07
2016Q4	1427.33	1391.67	35.6667	2.50%	1.44
2017Q1	1420.67	1409.14	11.5227	0.81%	0.46
2017Q2	1409.33	1405.71	3.62333	0.26%	0.15
2017Q3	1394.33	1401.5	-7.17156	-0.51%	(0.29)
2017Q4	1393.33	1397.37	-4.03895	-0.29%	(0.16)
2018Q1	1407.67	1395.73	11.9353	0.85%	0.48
2018Q2	1388.67	1405.41	-16.7429	-1.21%	(0.68)
2018Q3	1344.67	1332.79	11.8743	0.88%	0.48
2018Q4	1285.33	1340.51	-55.1756	-4.29%	(2.23)
2019Q1	1297	1307.46	-10.456	-0.81%	(0.42)
2019Q2	1297	1312.91	-15.9138	-1.23%	(0.64)
2019Q3	1317	1310.9	6.10097	0.46%	0.25
2019Q4	1349	1321.52	27.4825	2.04%	1.11
2020Q1	1322.33	1341.01	-18.6798	-1.41%	(0.75)
2020Q2	1318.33	1325.53	-7.20041	-0.55%	(0.29)
2020Q3	1331.33	1322.95	8.38156	0.63%	0.34
2020Q4	1345	1328.9	16.1024	1.20%	0.65
2021Q1	1343.33	1337.4	5.9367	0.44%	0.24
2021Q2	1338.33	1336.61	1.72758	0.13%	0.07
2021Q3	1339	1335.81	3.18566	0.24%	0.13
2021Q4	1390.33	1397.61	-7.27808	-0.52%	(0.29)
2022Q1	1400	1389.42	10.5818	0.76%	0.43
2022Q2	1403.33	1394.27	9.06033	0.65%	0.37
2022Q3	1379	1397.32	-18.3178	-1.33%	(0.74)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	1390.333	1398.95	-8.62	-0.6%
Q1 2022	1400	1395.504	4.50	0.3%
Q2 2022	1403.333	1392.684	10.65	0.8%
Q3 2022	1379	1392.22	-13.22	-1.0%
Total	5572.67	5579.36	-6.69	-0.1%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	1471.081	1478.811	-7.73	-1%
S_HLFNGP_S_ROLL12(-2)	-8.390939	-8.912536	0.521597	-6%
S_D14Q3_D16Q3	-95.57161	-96.3454	0.77379	-1%
S_D18Q3_D21Q3	-60.94486	-64.67685	3.73199	-6%
AR(1)	0.581701	0.580751	0.00095	0%

LLFUPC Sales Cambridge
IV. Sales - Use Per Customer
A. Low Load Factor Use Per Customer - Sales
1. Cambridge

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
B_LLF_UPC_SALES	11	0.998	1.895

ARIMA Model Parameters

B_LLF_UPC_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	29.28786	8.636	3.39	0.002
	B_LLFNGP_S_ROLL12(-1)	-1.315729	0.571	-2.30	0.028
	B_Q1_EDD	0.051145	0.001	91.67	0.000
	B_Q2_EDD+B_Q4_EDD	0.035473	0.001	33.36	0.000
	B_D19Q4_AFT*Q4	6.951252	2.490	2.79	0.009
	B_D15Q1	20.70316	4.049	5.11	0.000
	B_D21Q1	25.85158	3.843	6.73	0.000
	B_D22Q1	19.68212	3.899	5.05	0.000
	Q2	6.696814	1.562	4.29	0.000
	B_D18Q1	11.26889	4.075	2.77	0.010
	B_D15Q4	-8.796967	3.861	-2.28	0.030

Variable	Definition	Explanation	Dummy Variable Support
B_LLFNGP_S_ROLL12(-1)	Rolling 12 quarter natural gas price for low load factor sales		
B_Q1_EDD	Effective Degree Days in Brockton in Q1	A	
B_Q2_EDD+B_Q4_EDD	Effective Degree Days in Brockton in Q2 and Q4	A	
B_D19Q4_AFT*Q4	Binary variable equal to 1 Q4 from 2019Q4 on	C	1
B_D15Q1	Binary variable equal to 1 in 2015Q1		2
B_D21Q1	Binary variable equal to 1 in 2021Q1		2
B_D22Q1	Binary variable equal to 1 in 2022Q1		2
Q2	Binary variable equal to 1 in Q2	C	
B_D18Q1	Binary variable equal to 1 in 2018Q1		2
B_D15Q4	Binary variable equal to 1 in 2015Q4		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
42	0.997007	1366.718

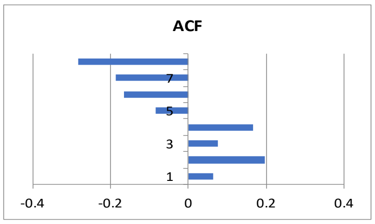
Chow Test Stats

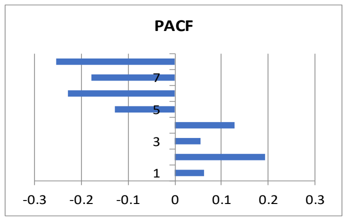
	N	k	SSR
Combined	42	11	399.36
1	20	7	278.87
2	22	9	57.61

Chow Stat:	0.34
P-Value:	0.965249

Heteroscedasticity - White's Test	
White Stat	0.95
Significance (p-value)	0.50

Correlations										
	B_LLFNGP_S_ROLL12(-1)	B_Q1_EDD	B_Q2_EDD+B_Q4_EDD	B_D19Q4_AFT*Q4	B_D15Q1	B_D21Q1	B_D22Q1	Q2	B_D18Q1	B_D15Q4
B_LLFNGP_S_ROLL12(-1)	1	-0.002675	0.029201	-0.16496	0.178268	-0.054295	-0.14382	0.022918	-0.2577	0.177172
B_Q1_EDD	-0.002675	1	-0.541868	-0.153855	0.354294	0.239995	0.246583	-0.33045	0.291725	-0.08664
B_Q2_EDD+B_Q4_EDD	0.029201	-0.541868	1	0.301885	-0.15255	-0.152552	-0.15255	0.44736	-0.15255	0.161479
B_D19Q4_AFT*Q4	-0.16496	-0.153855	0.301885	1	-0.04332	-0.043315	-0.04332	-0.16521	-0.04332	-0.04332
B_D15Q1	0.178268	0.354294	-0.152552	-0.043315	1	-0.02439	-0.02439	-0.09303	-0.02439	-0.02439
B_D21Q1	-0.054295	0.239995	-0.152552	-0.043315	-0.02439	1	-0.02439	-0.09303	-0.02439	-0.02439
B_D22Q1	-0.143817	0.246583	-0.152552	-0.043315	-0.02439	-0.02439	1	-0.09303	-0.02439	-0.02439
Q2	0.022918	-0.330445	0.44736	-0.165213	-0.09303	-0.09303	-0.09303	1	-0.09303	-0.09303
B_D18Q1	-0.257704	0.291725	-0.152552	-0.043315	-0.02439	-0.02439	-0.02439	-0.09303	1	-0.02439
B_D15Q4	0.177172	-0.086635	0.161479	-0.043315	-0.02439	-0.02439	-0.02439	-0.09303	-0.02439	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_llf_upc_sales Model	ACF	0.063	0.196	0.075	0.167	-0.085	-0.165	-0.187	-0.282
	SE	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_llf_upc_sales Model		0.063	0.193	0.055	0.129	-0.129	-0.23	-0.179	-0.255
	SE	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2012Q2	40.1486	50.1617	-10.0131	-24.94%	(2.79)
2012Q3	9.67942	7.89843	1.78099	18.40%	0.50
2012Q4	64.5017	66.3164	-1.81469	-2.81%	(0.51)
2013Q1	177.042	179.397	-2.35474	-1.33%	(0.66)
2013Q2	58.6677	60.8866	-2.21887	-3.78%	(0.62)
2013Q3	11.2793	7.8011	3.47822	30.84%	0.97
2013Q4	72.9491	73.8223	-0.87327	-1.20%	(0.24)
2014Q1	208.211	202.129	6.08187	2.92%	1.69
2014Q2	67.7111	62.9731	4.73799	7.00%	1.32
2014Q3	11.3109	7.81682	3.49408	30.89%	0.97
2014Q4	69.8662	69.4566	0.40967	0.59%	0.11
2015Q1	232.213	232.213	1.1E-14	0.00%	0.00
2015Q2	68.2673	62.236	6.03137	8.83%	1.68
2015Q3	10.8626	7.88772	2.97489	27.39%	0.83
2015Q4	51.4755	51.4755	5.3E-15	0.00%	0.00
2016Q1	155.204	160.065	-4.86017	-3.13%	(1.35)
2016Q2	59.8944	60.4453	-0.55098	-0.92%	(0.15)
2016Q3	9.43787	9.56637	-0.1285	-1.36%	(0.04)
2016Q4	62.6625	67.7095	-5.04701	-8.05%	(1.41)
2017Q1	167.173	170.851	-3.67809	-2.20%	(1.02)
2017Q2	65.275	65.4105	-0.13555	-0.21%	(0.04)
2017Q3	8.33228	11.4636	-3.13135	-37.58%	(0.87)
2017Q4	64.0516	62.7654	1.28626	2.01%	0.36
2018Q1	197.835	197.835	6.4E-14	0.00%	0.00
2018Q2	70.361	66.4411	3.9199	5.57%	1.09
2018Q3	8.20193	11.5254	-3.32347	-40.52%	(0.93)
2018Q4	79.724	75.7168	4.00722	5.03%	1.12
2019Q1	184.508	184.453	0.05429	0.03%	0.02
2019Q2	61.5946	60.9587	0.63588	1.03%	0.18
2019Q3	9.93729	10.0062	-0.0689	-0.69%	(0.02)
2019Q4	77.1317	78.7992	-1.6675	-2.16%	(0.46)
2020Q1	159.266	155.51	3.75555	2.36%	1.05
2020Q2	64.9323	66.3116	-1.37933	-2.12%	(0.38)
2020Q3	9.51466	9.71232	-0.19766	-2.08%	(0.06)
2020Q4	66.4871	65.8476	0.63947	0.96%	0.18
2021Q1	186.688	186.688	2.8E-14	0.00%	0.00
2021Q2	60.3633	58.6986	1.66476	2.76%	0.46
2021Q3	11.0504	10.7583	0.29213	2.64%	0.08
2021Q4	69.6456	68.6176	1.02803	1.48%	0.29
2022Q1	184.372	184.372	-1.8E-14	0.00%	0.00
2022Q2	55.4477	58.1398	-2.69207	-4.86%	(0.75)
2022Q3	8.20741	10.3447	-2.13734	-26.04%	(0.60)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	69.64561	68.19188	1.45	2.1%
Q1 2022	184.3715	164.8242	19.55	10.6%
Q2 2022	55.44771	58.52877	-3.08	-5.6%
Q3 2022	8.207411	10.63166	-2.42	-29.5%
Total	317.67	302.18	15.50	4.9%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	29.28786	30.93407	-1.64621	-6%
B_LLFNGP_S_ROLL12(-1)	-1.315729	-1.410142	0.094413	-7%
B_Q1_EDD	0.051145	0.051083	6.2E-05	0%
B_Q2_EDD+B_Q4_EDD	0.035473	0.035335	0.000138	0%
B_D19Q4_AFT*Q4	6.951252	6.388145	0.563107	8%
B_D15Q1	20.70316	20.83783	-0.13467	-1%
B_D21Q1	25.85158	25.77124	0.08034	0%
B_D22Q1	19.68212	0	19.68212	100%
Q2	6.696814	6.928416	-0.231602	-3%
B_D18Q1	11.26889	11.0853	0.18359	2%
B_D15Q4	-8.796967	-8.705543	-0.091424	1%

LLFUPC Sales Lawrence
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Model Statistics

Model	Number of Predictors	Model Fit Statistics: R-Squared	RMSE
L_LLF_UPC_SALES	13	0.994	2.572

ARIMA Model Parameters

L_LLF_UPC_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	17.13605	1.868	9.17	0.000
	L_LLFNGP_S*L_D15 Q2_AFT	-0.315891	0.151	-2.09	0.041
	L_Q1_EDD	0.057048	0.001	81.90	0.000
	L_Q4_EDD	0.039263	0.001	29.69	0.000
	L_Q2_EDD	0.046795	0.002	27.75	0.000
	L_D15Q1	27.43611	7.024	3.91	0.000
	L_D15Q2	16.25257	7.029	2.31	0.025
	L_D19Q4	16.56598	7.011	2.36	0.022
	L_D11Q4_13Q2	-15.48428	2.794	-5.54	0.000
	L_D17Q1	-15.29571	6.911	-2.21	0.031
	L_D07Q1	27.78214	6.938	4.00	0.000
	L_D20Q4_AFT	16.47661	2.925	5.63	0.000
	L_D22Q1	20.41871	7.260	2.81	0.007

Variable	Definition	Explanation	Dummy Variable Support
L_LLFNGP_S*L_D15Q2_AFT	Natural gas price for low load factor sales customers in Lawrence ($2022) after 2015Q2		
L_Q1_EDD	Effective Degree Days in Lawrence in Q1	A	
L_Q4_EDD	Effective Degree Days in Lawrence in Q2	A	
L_Q2_EDD	Effective Degree Days in Lawrence in Q4	A	
L_D15Q1	Binary variable equal to 1 in 2015Q1		2
L_D15Q2	Binary variable equal to 1 in 2015Q2		2
L_D19Q4	Binary variable equal to 1 in 2019Q4		2
L_D11Q4_13Q2	Binary variable equal to 1 in 2011Q4 to 2013Q2		2
L_D17Q1	Binary variable equal to 1 in 2017Q1		2
L_D07Q1	Binary variable equal to 1 in 2007Q1		2
L_D20Q4_AFT	Binary variable equal to 1 from 2020Q4 on		1
L_D22Q1	Binary variable equal to 1 in 2022Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

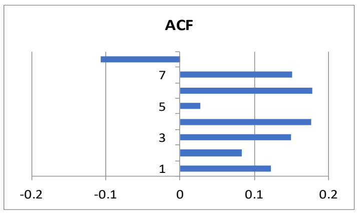
N	Adjusted R2	F Statistic
67	0.992598	738.5814

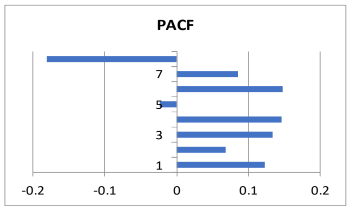
Chow Test Stats	N	k	SSR
Combined	67	13	2,361.30
1	44	9	1,689.02
2	23	9	333.09

Chow Stat:	0.529
P-Value:	0.892822

Heteroscedasticity - White's Test	
White Stat	0.63
Significance (p-value)	0.81

Correlations												
	L_LLFNGP_S*L_D15Q2_AFT	L_Q1_EDD	L_Q4_EDD	L_Q2_EDD	L_D15Q1	L_D15Q2	L_D19Q4	L_D11Q4_13Q2	L_D17Q1	L_D07Q1	L_D20Q4_AFT	L_D22Q1
L_LLFNGP_S*L_D15Q2_AFT	1	-0.07482	-0.031117	0.038517	-0.10944	0.179815	0.147151	-0.30368	0.096806	-0.10944	0.405488	0.142272
L_Q1_EDD	-0.07482	1	-0.323249	-0.336128	0.262395	-0.071437	-0.07144	0.013542	0.194465	0.220192	-0.018384	0.189042
L_Q4_EDD	-0.031117	-0.323249	1	-0.322592	-0.06856	-0.06856	0.237345	0.024145	-0.06856	-0.06856	-0.017344	-0.06856
L_Q2_EDD	0.038517	-0.336128	-0.322592	1	-0.07129	0.233277	-0.07129	0.010656	-0.07129	-0.07129	-0.032554	-0.07129
L_D15Q1	-0.109439	0.262395	-0.06856	-0.071292	1	-0.015152	-0.01515	-0.042044	-0.01515	-0.01515	-0.045326	-0.01515
L_D15Q2	0.179815	-0.071437	-0.06856	0.233277	-0.01515	1	-0.01515	-0.042044	-0.01515	-0.01515	-0.045326	-0.01515
L_D19Q4	0.147151	-0.071437	0.237345	-0.071292	-0.01515	-0.015152	1	-0.042044	-0.01515	-0.01515	-0.045326	-0.01515
L_D11Q4_13Q2	-0.30368	0.013542	0.024145	0.010656	-0.04204	-0.042044	-0.04204	1	-0.04204	-0.04204	-0.125774	-0.04204
L_D17Q1	0.096806	0.194465	-0.06856	-0.071292	-0.01515	-0.015152	-0.01515	-0.042044	1	-0.01515	-0.045326	-0.01515
L_D07Q1	-0.109439	0.220192	-0.06856	-0.071292	-0.01515	-0.015152	-0.01515	-0.042044	-0.01515	1	-0.045326	-0.01515
L_D20Q4_AFT	0.405488	-0.018384	-0.017344	-0.032554	-0.04533	-0.045326	-0.04533	-0.125774	-0.04533	-0.04533	1	0.334279
L_D22Q1	0.142272	0.189042	-0.06856	-0.071292	-0.01515	-0.015152	-0.01515	-0.042044	-0.01515	-0.01515	0.334279	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_llf_upc_sales Model	ACF	0.123	0.083	0.149	0.177	0.028	0.178	0.151	-0.106
	SE	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_llf_upc_sales Model		0.123	0.069	0.134	0.146	-0.023	0.148	0.086	-0.181
	SE	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2006Q1	230.449	212.252	18.1975	7.90%	2.75
2006Q2	91.6267	80.5521	11.0745	12.09%	1.67
2006Q3	20.6138	17.136	3.47774	16.87%	0.53
2006Q4	83.4819	80.4567	3.02513	3.62%	0.46
2007Q1	252.652	252.652	-1.8E-14	0.00%	0.00
2007Q2	102.782	86.4327	16.3491	15.91%	2.47
2007Q3	20.1337	17.136	2.9977	14.89%	0.45
2007Q4	98.7895	89.3994	9.39005	9.51%	1.42
2008Q1	219.003	216.753	2.24939	1.03%	0.34
2008Q2	80.7621	84.8417	-4.07957	-5.05%	(0.62)
2008Q3	14.5954	17.136	-2.54067	-17.41%	(0.38)
2008Q4	89.3471	91.8936	-2.54646	-2.85%	(0.39)
2009Q1	235.676	234.368	1.30887	0.56%	0.20
2009Q2	78.0085	79.4246	-1.41604	-1.82%	(0.21)
2009Q3	21.4551	17.136	4.31901	20.13%	0.65
2009Q4	78.8478	87.842	-8.9942	-11.41%	(1.36)
2010Q1	214.632	219.779	-5.14795	-2.40%	(0.78)
2010Q2	58.3762	66.8925	-8.51624	-14.59%	(1.29)
2010Q3	15.2967	17.136	-1.83938	-12.02%	(0.28)
2010Q4	86.1279	92.2114	-6.08352	-7.06%	(0.92)
2011Q1	231.107	229.795	1.31123	0.57%	0.20
2011Q2	78.3922	84.8149	-6.42276	-8.19%	(0.97)
2011Q3	15.4676	17.136	-1.66845	-10.79%	(0.25)
2011Q4	68.1892	61.6706	6.51857	9.56%	0.99
2012Q1	171.446	180.473	-9.0272	-5.27%	(1.37)
2012Q2	50.1599	54.0376	-3.87766	-7.73%	(0.59)
2012Q3	13.5353	1.65177	11.8835	87.80%	1.80
2012Q4	75.1751	72.3241	2.85105	3.79%	0.43
2013Q1	195.889	203.366	-7.47684	-3.82%	(1.13)
2013Q2	67.3851	68.2566	-0.87146	-1.29%	(0.13)
2013Q3	13.1825	17.136	-3.95357	-29.99%	(0.60)
2013Q4	85.7211	96.1191	-10.398	-12.13%	(1.57)
2014Q1	240.867	244.769	-3.90262	-1.62%	(0.59)
2014Q2	88.1795	86.9541	1.22542	1.39%	0.19
2014Q3	14.1775	17.136	-2.95854	-20.87%	(0.45)
2014Q4	85.3233	90.5867	-5.26337	-6.17%	(0.80)

2015Q1	282.368	282.368	-8.2E-14	0.00%	0.00
2015Q2	97.4709	97.4709	3.6E-15	0.00%	0.00
2015Q3	13.4358	12.3716	1.06423	7.92%	0.16
2015Q4	73.9473	77.1508	-3.20345	-4.33%	(0.48)
2016Q1	192.463	192.836	-0.37316	-0.19%	(0.06)
2016Q2	74.0321	78.6986	-4.66646	-6.30%	(0.71)
2016Q3	16.6491	13.9775	2.6716	16.05%	0.40
2016Q4	77.0553	84.2064	-7.15105	-9.28%	(1.08)
2017Q1	187.807	187.807	-4.1E-14	0.00%	0.00
2017Q2	80.8259	83.8894	-3.06345	-3.79%	(0.46)
2017Q3	13.6238	13.4309	0.19283	1.42%	0.03
2017Q4	80.545	75.3075	5.23748	6.50%	0.79
2018Q1	223.845	220.814	3.03016	1.35%	0.46
2018Q2	78.1813	81.1041	-2.92277	-3.74%	(0.44)
2018Q3	12.2125	12.4462	-0.23369	-1.91%	(0.04)
2018Q4	98.135	91.3413	6.79372	6.92%	1.03
2019Q1	215.253	217.403	-2.15042	-1.00%	(0.33)
2019Q2	75.8008	76.9883	-1.18744	-1.57%	(0.18)
2019Q3	12.834	12.7609	0.07309	0.57%	0.01
2019Q4	103.342	103.342	-2.1E-14	0.00%	0.00
2020Q1	185.493	187.822	-2.32913	-1.26%	(0.35)
2020Q2	84.3327	78.4831	5.84958	6.94%	0.88
2020Q3	16.5687	13.3946	3.17404	19.16%	0.48
2020Q4	92.6245	92.6183	0.00619	0.01%	0.00
2021Q1	220.546	216.381	4.16442	1.89%	0.63
2021Q2	86.8079	84.4765	2.33138	2.69%	0.35
2021Q3	20.517	29.7972	-9.28014	-45.23%	(1.40)
2021Q4	103.119	88.1689	14.9504	14.50%	2.26
2022Q1	235.376	235.376	1.8E-14	0.00%	0.00
2022Q2	81.0288	83.7881	-2.7593	-3.41%	(0.42)
2022Q3	19.3386	28.7515	-9.41294	-48.67%	(1.42)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	103.1193	86.82857	16.29	15.8%
Q1 2022	235.3764	214.3267	21.05	8.9%
Q2 2022	81.02885	83.32564	-2.30	-2.8%
Q3 2022	19.33861	28.55916	-9.22	-47.7%
Total	438.86	413.04	25.82	5.9%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	17.13605	17.58967	-0.45362	-3%
L_LLFNGP_S*L_D15Q2_AFT	-0.315891	-0.307366	-0.008525	3%
L_Q1_EDD	0.057048	0.056919	0.000129	0%
L_Q4_EDD	0.039263	0.038509	0.000754	2%
L_Q2_EDD	0.046795	0.046571	0.000224	0%
L_D15Q1	27.43611	27.52184	-0.08573	0%
L_D15Q2	16.25257	15.99869	0.25388	2%
L_D19Q4	16.56598	17.41695	-0.85097	-5%
L_D11Q4_13Q2	-15.48428	-15.37451	-0.10977	1%
L_D17Q1	-15.29571	-15.4126	0.11689	-1%
L_D07Q1	27.78214	27.79969	-0.01755	0%
L_D20Q4_AFT	16.47661	15.69942	0.77719	5%
L_D22Q1	20.41871	0	20.41871	

LLFUPC Sales Springfield
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
S_LLF_UPC_SALES	14	0.995	2.286

ARIMA Model Parameters

S_LLF_UPC_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	17.81949	3.027	5.89	0.000
	S_LLFNGP_S(-1)	-0.368617	0.165	-2.24	0.029
	S_Q1_EDD	0.048436	0.001	80.34	0.000
	S_Q4_EDD+S_Q2_EDD	0.036879	0.001	34.23	0.000
	S_D14Q1	20.30493	5.567	3.65	0.001
	S_D09Q4_D13Q3	-5.728949	1.997	-2.87	0.006
	S_D15Q1	40.55399	5.572	7.28	0.000
	S_D18Q1	41.78724	5.571	7.50	0.000
	S_D19Q1	26.55156	5.517	4.81	0.000
	S_D22Q1	26.04564	5.508	4.73	0.000
	S_D18Q4	24.69278	5.399	4.57	0.000
	S_D17Q1	19.47838	5.566	3.50	0.001
	S_D17Q4	16.48361	5.362	3.07	0.003
	S_D18Q2	12.47973	5.321	2.35	0.023

Variable	Definition	Explanation	Dummy Variable Support
S_LLFNGP_S(-1)	Natural gas price for low load factor sales customers in Springfield ($2022) lagged one quarter		
S_Q1_EDD	Effective Degree Days in Springfield in Q1	A	
S_Q4_EDD+S_Q2_EDD	Effective Degree Days in Springfield in Q2 and Q4	A	
S_D14Q1	Binary variable equal to 1 in 2014Q1	A	
S_D09Q4_D13Q3	Binary variable equal to 1 from 2009Q4 to 2013Q3		2
S_D15Q1	Binary variable equal to 1 in 2015Q1		2
S_D18Q1	Binary variable equal to 1 in 2018Q1		2
S_D19Q1	Binary variable equal to 1 in 2019Q1		2
S_D22Q1	Binary variable equal to 1 in 2022Q1		2
S_D18Q4	Binary variable equal to 1 in 2018Q4		2
S_D17Q1	Binary variable equal to 1 in 2017Q1		2
S_D17Q4	Binary variable equal to 1 in 2017Q4		2
S_D18Q2	Binary variable equal to 1 in 2018Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
68	0.993885	838.6082

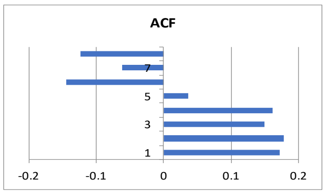
Chow Test Stats

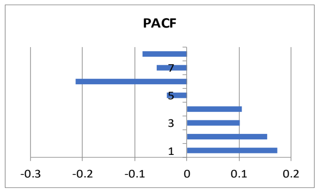
	N	k	SSR
Combined	63	14	1,475.40
1	33	5	435.55
2	35	13	472.35

Chow Stat:	1.786
P-Value:	0.075924

Heteroscedasticity - White's Test	
White Stat	0.74
Significance (p-value)	0.72

Correlations	S_LLFNGP_S(-1)	S_Q1_EDD	S_Q4_EDD+S_Q2_EDD	S_D14Q1	S_D09Q4_D13Q3	S_D15Q1	S_D18Q1	S_D19Q1	S_D22Q1	S_D18Q4	S_D17Q1	S_D17Q4	S_D18Q2
S_LLFNGP_S(-1)	1	0.059967	-0.110416	-0.015985	0.086575	0.037323	-0.1104	-0.03717	-0.05369	-0.04173	-0.1581	-0.11794	-0.08699
S_Q1_EDD	0.059967	1	-0.55267	0.247383	0.006746	0.25537	0.220653	0.218055	0.208632	-0.07024	0.192463	-0.07024	-0.07024
S_Q4_EDD+S_Q2_EDD	-0.110416	-0.55267	1	-0.11743	-0.011739	-0.11743	-0.11743	-0.11743	-0.11743	0.200752	-0.11743	0.136639	0.097048
S_D14Q1	-0.015985	0.247383	-0.11743	1	-0.04461	-0.014925	-0.01493	-0.01493	-0.01493	-0.01493	-0.01493	-0.01493	-0.01493
S_D09Q4_D13Q3	0.086575	0.006746	-0.011739	-0.04461	1	-0.04461	-0.04461	-0.04461	-0.04461	-0.04461	-0.04461	-0.04461	-0.04461
S_D15Q1	0.037323	0.25537	-0.11743	-0.014925	-0.04461	1	-0.01493	-0.01493	-0.01493	-0.01493	-0.01493	-0.01493	-0.01493
S_D18Q1	-0.110395	0.220653	-0.11743	-0.014925	-0.04461	-0.014925	1	-0.01493	-0.01493	-0.01493	-0.01493	-0.01493	-0.01493
S_D19Q1	-0.03717	0.218055	-0.11743	-0.014925	-0.04461	-0.014925	-0.01493	1	-0.01493	-0.01493	-0.01493	-0.01493	-0.01493
S_D22Q1	-0.053692	0.208632	-0.11743	-0.014925	-0.04461	-0.014925	-0.01493	-0.01493	1	-0.01493	-0.01493	-0.01493	-0.01493
S_D18Q4	-0.041728	-0.070244	0.200752	-0.014925	-0.04461	-0.014925	-0.01493	-0.01493	-0.01493	1	-0.01493	-0.01493	-0.01493
S_D17Q1	-0.1581	0.192463	-0.11743	-0.014925	-0.04461	-0.014925	-0.01493	-0.01493	-0.01493	-0.01493	1	-0.01493	-0.01493
S_D17Q4	-0.117936	-0.070244	0.136639	-0.014925	-0.04461	-0.014925	-0.01493	-0.01493	-0.01493	-0.01493	-0.01493	1	-0.01493
S_D18Q2	-0.086988	-0.070244	0.097048	-0.014925	-0.04461	-0.014925	-0.01493	-0.01493	-0.01493	-0.01493	-0.01493	-0.01493	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_llf_upc_sales Model	ACF	0.173	0.179	0.15	0.161	0.037	-0.145	-0.061	-0.124
	SE	0.243	0.243	0.243	0.243	0.243	0.243	0.243	0.243
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_llf_upc_sales Model		0.173	0.154	0.102	0.105	-0.038	-0.213	-0.057	-0.086
	SE	0.243	0.243	0.243	0.243	0.243	0.243	0.243	0.243

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2005Q4	75.5852	81.6859	-6.10066	-8.07%	(1.17)
2006Q1	168.571	168.924	-0.35297	-0.21%	(0.07)
2006Q2	49.9724	49.8263	0.14614	0.29%	0.03
2006Q3	11.9652	8.82146	3.14372	26.27%	0.60
2006Q4	60.8511	63.0423	-2.19115	-3.60%	(0.42)
2007Q1	177.434	177.175	0.25908	0.15%	0.05
2007Q2	57.121	54.711	2.41005	4.22%	0.46
2007Q3	10.6936	9.82668	0.8669	8.11%	0.17
2007Q4	71.9765	69.645	2.33152	3.24%	0.45
2008Q1	175.336	171.644	3.69187	2.11%	0.71
2008Q2	47.9043	53.1111	-5.20682	-10.87%	(1.00)
2008Q3	10.1138	10.2619	-0.14804	-1.46%	(0.03)
2008Q4	71.7546	74.8142	-3.05962	-4.26%	(0.59)
2009Q1	183.31	186.625	-3.31481	-1.81%	(0.63)
2009Q2	41.7832	51.5921	-9.80891	-23.48%	(1.88)
2009Q3	12.57	9.91198	2.65798	21.15%	0.51
2009Q4	66.6628	66.7283	-0.06553	-0.10%	(0.01)
2010Q1	168.768	170.13	-1.36218	-0.81%	(0.26)
2010Q2	32.9183	36.3099	-3.39165	-10.30%	(0.65)
2010Q3	10.269	6.18532	4.08369	39.77%	0.78
2010Q4	71.8633	70.5976	1.26572	1.76%	0.24
2011Q1	177.579	182.025	-4.44665	-2.50%	(0.85)
2011Q2	48.5215	48.9831	-0.46163	-0.95%	(0.09)
2011Q3	9.90097	5.52273	4.37823	44.22%	0.84
2011Q4	59.1308	64.9302	-5.79943	-9.81%	(1.11)

2012Q1	147.04	152.183	-5.14276	-3.50%	(0.98)
2012Q2	32.9001	43.1566	-10.2565	-31.17%	(1.96)
2012Q3	10.5295	11.7644	-1.23495	-11.73%	(0.24)
2012Q4	66.6879	72.2948	-5.60689	-8.41%	(1.07)
2013Q1	168.609	176.048	-7.43876	-4.41%	(1.42)
2013Q2	46.1419	56.188	-10.0461	-21.77%	(1.92)
2013Q3	10.5849	12.2303	-1.64534	-15.54%	(0.31)
2013Q4	84.03	79.4821	4.54789	5.41%	0.87
2014Q1	218.945	218.945	-1.1E-14	0.00%	(0.00)
2014Q2	62.4848	56.1869	6.29792	10.08%	1.20
2014Q3	12.4628	11.3613	1.10146	8.84%	0.21
2014Q4	79.1118	71.8547	7.25709	9.17%	1.39
2015Q1	243.235	243.235	1.4E-14	0.00%	(0.00)
2015Q2	63.7153	53.7672	9.94803	15.61%	1.90
2015Q3	11.9133	12.053	-0.1397	-1.17%	(0.03)
2015Q4	61.6192	65.0654	-3.44618	-5.59%	(0.66)
2016Q1	167.621	158.408	9.2127	5.50%	1.76
2016Q2	55.7546	56.0652	-0.31063	-0.56%	(0.06)
2016Q3	12.66	13.7056	-1.04563	-8.26%	(0.20)
2016Q4	80.3841	75.5001	4.884	6.08%	0.93
2017Q1	187.581	187.581	5E-14	0.00%	(0.00)
2017Q2	61.4688	59.4239	2.04488	3.33%	0.39
2017Q3	10.9104	13.3184	-2.40801	-22.07%	(0.46)
2017Q4	85.6884	85.6884	2.8E-14	0.00%	(0.00)
2018Q1	225.873	225.873	-1.4E-14	0.00%	(0.00)
2018Q2	72.581	72.581	-8.9E-15	0.00%	(0.00)
2018Q3	12.7579	12.1774	0.58053	4.55%	0.11
2018Q4	107.093	107.093	1.1E-14	0.00%	(0.00)
2019Q1	208.214	208.214			
2019Q2	62.1487	51.9591	10.1896	16.40%	1.95
2019Q3	14.1851	12.641	1.5441	10.89%	0.30
2019Q4	92.2509	76.8929	15.358	16.65%	2.94
2020Q1	167.362	161.863	5.49836	3.29%	1.05
2020Q2	57.3793	63.7249	-6.34552	-11.06%	(1.21)
2020Q3	10.8722	12.9965	-2.1243	-19.54%	(0.41)
2020Q4	74.5616	74.9091	-0.34755	-0.47%	(0.07)
2021Q1	181.968	177.146	4.82194	2.65%	0.92
2021Q2	51.1314	56.2307	-5.09927	-9.97%	(0.98)
2021Q3	11.0394	12.7847	-1.74536	-15.81%	(0.33)
2021Q4	73.622	73.8322	-0.21018	-0.29%	(0.04)
2022Q1	202.373	202.373	2.1E-14	0.00%	(0.00)
2022Q2	58.2958	56.3009	1.99491	3.42%	0.38
2022Q3	11.6518	11.8644	-0.21259	-1.82%	(0.04)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	73.62198	73.76751	-0.15	-0.2%
Q1 2022	202.3726	176.3153	26.06	12.9%
Q2 2022	58.29582	56.25125	2.04	3.5%
Q3 2022	11.65177	11.85001	-0.20	-1.7%
Total	345.94	318.18	27.76	8.0%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	17.81949	17.7774	0.04209	0%
S_LLFNGP_S(-1)	-0.368617	-0.3669	-0.001717	0%
S_Q1_EDD	0.048436	0.048438	-2E-06	0%
S_Q4_EDD+S_Q2_EDD	0.036879	0.036851	2.8E-05	0%
S_D14Q1	20.30493	20.3137	-0.00877	0%
S_D09Q4_D13Q3	-5.728949	-5.698985	-0.029964	1%
S_D15Q1	40.55399	40.55957	-0.00558	0%
S_D18Q1	41.78724	41.8019	-0.01466	0%
S_D19Q1	26.55156	26.5621	-0.01054	0%
S_D22Q1	26.04564	0	26.04564	
S_D18Q4	24.69278	24.76257	-0.06979	0%
S_D17Q1	19.47838	19.4963	-0.01792	0%
S_D17Q4	16.48361	16.54697	-0.06336	0%
S_D18Q2	12.47973	12.53467	-0.05494	0%

HLFUPC Sales Brockton
A. High Load Factor Use Per Customer - Sales
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
B_HLF_UPC_SALES	11	0.959	3.001

ARIMA Model Parameters

B_HLF_UPC_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	198.9012	7.684	25.89	0.000
	B_HLFNGP_S_ROLL12(-3)	-6.257524	0.650	-9.63	0.000
	B_Q1_EDD+B_Q2_EDD	0.026248	0.001	24.15	0.000
	B_Q4_EDD	0.019118	0.002	9.27	0.000
	B_D2012	-25.28715	4.937	-5.12	0.000
	B_D2013	-24.67256	4.825	-5.11	0.000
	B_D20Q2_D21Q3	-24.79063	4.661	-5.32	0.000
	B_AFT_D20Q4	12.6171	4.206	3.00	0.005
	B_D2015	16.3111	4.844	3.37	0.002
	B_D10Q1	45.2677	9.658	4.69	0.000
	B_D10Q2	32.01447	9.751	3.28	0.002

Variable	Definition	Explanation	Dummy Variable Support
B_HLFNGP_S_ROLL12(-3)	Rolling 12 quarter natural gas price for high load factor sales customers in Brockton ($2022) lagged three quarters		
B_Q1_EDD+B_Q2_EDD	Effective Degree Days in Brockton in Q1 and Q2	A	
B_Q4_EDD	Effective Degree Days in Brockton in Q4	A	
B_D2012	Binary variable equal to 1 in 2012		2
B_D2013	Binary variable equal to 1 in 2013		2
B_D20Q2_D21Q3	Binary variable equal to 1 from 2020Q2 to 2021Q3		2
B_AFT_D20Q4	Binary variable equal to 1 from 2020Q4 on		1
B_D2015	Binary variable equal to 1 in 2015Q2		2
B_D10Q1	Binary variable equal to 1 in 2010Q1		2
B_D10Q2	Binary variable equal to 1 in 2010Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
52	0.948605	95.13196

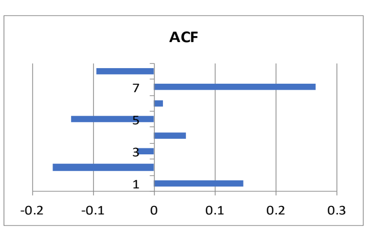
Chow Test Stats	N	k	SSR
Combined	52	11	3,325.67
1	27	9	1,217.61
2	25	6	1,402.20

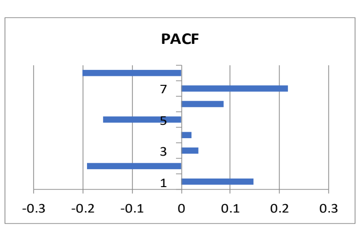
Chow Stat:	0.735
P-Value:	0.697518

Heteroscedasticity - White's Test	
White Stat	1.45
Significance (p-value)	0.19

Correlations

	B_HLFNGP_S_ROLL12(-3)	B_Q1_EDD+B_Q2_EDD	B_Q4_EDD	B_D2012	B_D2013	B_D20Q2_D21Q3	B_AFT_D20Q4	B_D2015	B_D10Q1	B_D10Q2
B_HLFNGP_S_ROLL12(-3)	1	-0.010784	0.067147	0.208568	0.076461	-0.315126	-0.372253	0.098944	0.179338	0.286781
B_Q1_EDD+B_Q2_EDD	-0.010784	1	-0.479506	-0.031271	0.00671	-0.056811	-0.031147	0.042086	0.234934	-0.02017
B_Q4_EDD	0.067147	-0.479506	1	0.00427	0.02451	-0.089165	-0.031908	-0.01418	-0.08033	-0.08033
B_D2012	0.208568	-0.031271	0.00427	1	-0.08333	-0.104257	-0.123091	-0.08333	-0.04042	-0.04042
B_D2013	0.076461	0.00671	0.02451	-0.083333	1	-0.104257	-0.123091	-0.08333	-0.04042	-0.04042
B_D20Q2_D21Q3	-0.315126	-0.056811	-0.089165	-0.104257	-0.10426	1	0.513327	-0.10426	-0.05057	-0.05057
B_AFT_D20Q4	-0.372253	-0.031147	-0.031908	-0.123091	-0.12309	0.513327	1	-0.12309	-0.05971	-0.05971
B_D2015	0.098944	0.042086	-0.014178	-0.083333	-0.08333	-0.104257	-0.123091	1	-0.04042	-0.04042
B_D10Q1	0.179338	0.234934	-0.080332	-0.040423	-0.04042	-0.050572	-0.059708	-0.04042	1	-0.01961
B_D10Q2	0.286781	-0.020166	-0.080332	-0.040423	-0.04042	-0.050572	-0.059708	-0.04042	-0.01961	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_hlf_upc_sales	ACF	0.147	-0.166	-0.026	0.053	-0.136	0.014	0.266	-0.095
	SE	0.277	0.277	0.277	0.277	0.277	0.277	0.277	0.277
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_hlf_upc_sales		0.147	-0.192	0.034	0.021	-0.158	0.087	0.217	-0.2
	SE	0.277	0.277	0.277	0.277	0.277	0.277	0.277	0.277

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2009Q4	139.288	126.99	12.2984	8.83%	1.37
2010Q1	244.442	244.442	-1.4E-14	0.00%	0.00
2010Q2	155.204	155.204	-2.8E-14	0.00%	0.00
2010Q3	109.864	101.46	8.40458	7.65%	0.93
2010Q4	130.744	137.181	-6.43668	-4.92%	(0.71)
2011Q1	196.826	199.979	-3.1531	-1.60%	(0.35)
2011Q2	145.107	141.961	3.14657	2.17%	0.35
2011Q3	109.63	107.813	1.81691	1.66%	0.20
2011Q4	134.913	136.389	-1.47602	-1.09%	(0.16)
2012Q1	174.794	164.12	10.6737	6.11%	1.19
2012Q2	119.209	118.34	0.86951	0.73%	0.10
2012Q3	94.7686	94.1047	0.66397	0.70%	0.07
2012Q4	116.182	128.389	-12.2072	-10.51%	(1.36)
2013Q1	172.663	187.222	-14.559	-8.43%	(1.62)
2013Q2	127.529	133.521	-5.99184	-4.70%	(0.67)
2013Q3	105.217	99.5188	5.6978	5.42%	0.63
2013Q4	150.971	136.118	14.853	9.84%	1.65
2014Q1	211.446	224.166	-12.7208	-6.02%	(1.41)
2014Q2	150.4	160.285	-9.88587	-6.57%	(1.10)
2014Q3	120.201	125.378	-5.17661	-4.31%	(0.57)
2014Q4	152.926	158.248	-5.32172	-3.48%	(0.59)
2015Q1	246.906	244.18	2.72602	1.10%	0.30
2015Q2	178.509	175.428	3.08033	1.73%	0.34
2015Q3	148.888	139.768	9.11916	6.12%	1.01
2015Q4	151.764	166.689	-14.9255	-9.83%	(1.66)
2016Q1	197.355	200.504	-3.14942	-1.60%	(0.35)
2016Q2	159.45	156.957	2.49305	1.56%	0.28
2016Q3	128.161	125.382	2.77906	2.17%	0.31
2016Q4	144.001	158.704	-14.7028	-10.21%	(1.63)
2017Q1	218.938	213.467	5.47109	2.50%	0.61
2017Q2	169.75	169.393	0.35702	0.21%	0.04
2017Q3	129.42	135.763	-6.34318	-4.90%	(0.70)
2017Q4	167.719	166.29	1.42883	0.85%	0.16
2018Q1	234.297	233.399	0.89725	0.38%	0.10
2018Q2	172.036	181.034	-8.99806	-5.23%	(1.00)
2018Q3	133.444	147.882	-14.4385	-10.82%	(1.60)
2018Q4	186.215	183.709	2.50585	1.35%	0.28
2019Q1	244.226	236.586	7.6395	3.13%	0.85
2019Q2	180.022	179.938	0.08381	0.05%	0.01
2019Q3	148.941	146.635	2.30669	1.55%	0.26
2019Q4	199.407	177.974	21.4332	10.75%	2.38
2020Q1	237.55	217.219	20.3305	8.56%	2.26
2020Q2	147.675	153.936	-6.26153	-4.24%	(0.70)
2020Q3	121.542	116.87	4.67202	3.84%	0.52
2020Q4	153.691	155.545	-1.85407	-1.21%	(0.21)
2021Q1	207.005	205.238	1.76741	0.85%	0.20
2021Q2	158.238	158.493	-0.25508	-0.16%	(0.03)
2021Q3	129.415	127.484	1.93124	1.49%	0.21
2021Q4	180.826	180.881	-0.05508	-0.03%	(0.01)
2022Q1	231.578	234.083	-2.50467	-1.08%	(0.28)
2022Q2	186.993	184.162	2.83054	1.51%	0.31
2022Q3	151.06	152.92	-1.8603	-1.23%	(0.21)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	180.826	182.1345	-1.31	-0.7%
Q1 2022	231.5782	235.429	-3.85	-1.7%
Q2 2022	186.9929	185.4826	1.51	0.8%
Q3 2022	151.06	154.223	-3.16	-2.1%
Total	750.46	757.27	-6.81	-0.9%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	198.9012	199.1758	-0.2746	0%
B_HLFNGP_S_ROLL12(-3)	-6.257524	-6.27646	0.018936	0%
B_Q1_EDD+B_Q2_EDD	0.026248	0.02626	-1.2E-05	0%
B_Q4_EDD	0.019118	0.019082	3.6E-05	0%
B_D2012	-25.28715	-25.31328	0.02613	0%
B_D2013	-24.67256	-24.71911	0.04655	0%
B_D20Q2_D21Q3	-24.79063	-25.6959	0.90527	-4%
B_AFT_D20Q4	12.6171	13.82251	-1.20541	-10%
B_D2015	16.3111	16.26254	0.04856	0%
B_D10Q1	45.2677	45.22149	0.04621	0%
B_D10Q2	32.01447	32.03203	-0.01756	0%

HLFUPC Sales Lawrence
2. Lawrence

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
L_HLF_UPC_SALES	9	0.951	0.266

ARIMA Model Parameters

L_HLF_UPC_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	6.327021	0.238	26.61	0.000
	LOG_L_HLFNGP_S_ROLL12(-3)	-0.627369	0.103	-6.09	0.000
	LOG_L_Q1_EDD	0.080666	0.005	17.60	0.000
	LOG_L_Q2_EDD	0.035906	0.005	7.07	0.000
	LOG_L_Q4_EDD	0.030978	0.005	6.17	0.000
	L_D16Q1	-0.242531	0.079	-3.06	0.006
	L_D21Q4+L_D22Q1	0.171101	0.055	3.13	0.005
	L_D2020	-0.150312	0.039	-3.85	0.001
	S_D17Q2	0.154737	0.076	2.03	0.055

Variable	Definition	Explanation	Dummy Variable Support
LOG_L_HLFNGP_S_ROLL12(-3)	Log of rolling 12 quarter natural gas price for high load factor sales customers in Lawrence ($2022) lagged three quarters		
LOG_L_Q1_EDD	Log of Effective Degree Days in Lawrence in Q1	A	
LOG_L_Q2_EDD	Log of Effective Degree Days in Lawrence in Q2	A	
LOG_L_Q4_EDD	Log of Effective Degree Days in Lawrence in Q4	A	
L_D16Q1	Binary variable equal to 1 in 2016Q1		2
L_D21Q4+L_D22Q1	Binary variable equal to 1 in 2021Q4 and 2022Q1		2
L_D2020	Binary variable equal to 1 in 2020		2
S_D17Q2	Binary variable equal to 1 in 2017Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
31	0.932996	53.21642

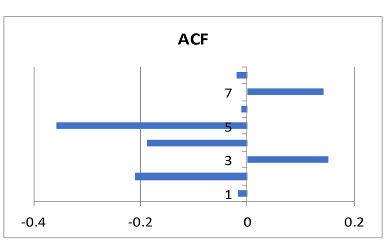
Chow Test Stats	N	k	SSR
Combined	31	9	0.11
1	16	7	0.05
2	15	7	0.03

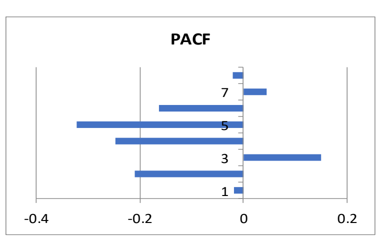
Chow Stat:	0.542
P-Value:	0.819958

Heteroscedasticity - White's Test	
White Stat	1.12
Significance (p-value)	0.39

Correlations

	LOG_L_HLFNGP_S_ROLL12(-3)	LOG_L_Q1_EDD	LOG_L_Q2_EDD	LOG_L_Q4_EDD	L_D16Q1	L_D21Q4+L_D22Q1	L_D2020	S_D17Q2
LOG_L_HLFNGP_S_ROLL12(-3)	1	0.040101	0.009255	-0.033409	0.292452	-0.121897	-0.20009	0.098359
LOG_L_Q1_EDD	0.040101	1	-0.347756	-0.318446	0.30531	0.143375	-0.01003	-0.10767
LOG_L_Q2_EDD	0.009255	-0.347756	1	-0.318439	-0.10766	-0.154863	-0.00631	0.315288
LOG_L_Q4_EDD	-0.033409	-0.318446	-0.318439	1	-0.09859	0.166586	0.020278	-0.09859
L_D16Q1	0.292452	0.30531	-0.107664	-0.09859	1	-0.047946	-0.07027	-0.03333
L_D21Q4+L_D22Q1	-0.121897	0.143375	-0.154863	0.166586	-0.04795	1	-0.10108	-0.04795
L_D2020	-0.200094	-0.010033	-0.006309	0.020278	-0.07027	-0.10108	1	-0.07027
S_D17Q2	0.098359	-0.107667	0.315288	-0.09859	-0.03333	-0.047946	-0.07027	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_hlf_upc_sales Model	ACF	-0.019	-0.211	0.151	-0.188	-0.357	-0.012	0.142	-0.02
	SE	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_hlf_upc_sales Model		-0.019	-0.211	0.149	-0.247	-0.321	-0.164	0.046	-0.02
	SE	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2015Q1	5.44904	5.43879	0.01025	0.19%	0.15
2015Q2	5.17517	5.02967	0.1455	2.81%	2.06
2015Q3	4.83553	4.76459	0.07093	1.47%	1.00
2015Q4	4.89276	4.98289	-0.09013	-1.84%	(1.28)
2016Q1	5.16386	5.16386	6.7E-16	0.00%	(0.00)
2016Q2	4.95184	5.02379	-0.07195	-1.45%	(1.02)
2016Q3	4.74326	4.77607	-0.03281	-0.69%	(0.46)
2016Q4	4.97106	5.02417	-0.05311	-1.07%	(0.75)
2017Q1	5.49853	5.47559	0.02294	0.42%	0.32
2017Q2	5.26292	5.26292	-2.2E-16	0.00%	(0.00)
2017Q3	4.82702	4.86613	-0.03911	-0.81%	(0.55)
2017Q4	5.18106	5.12252	0.05854	1.13%	0.83
2018Q1	5.61318	5.60966	0.00352	0.06%	0.05
2018Q2	5.16904	5.23228	-0.06324	-1.22%	(0.90)
2018Q3	4.96853	4.99625	-0.02772	-0.56%	(0.39)
2018Q4	5.16199	5.24756	-0.08556	-1.66%	(1.21)
2019Q1	5.71744	5.65526	0.06218	1.09%	0.88
2019Q2	5.27213	5.25637	0.01576	0.30%	0.22
2019Q3	5.00034	4.98849	0.01185	0.24%	0.17
2019Q4	5.29988	5.20095	0.09893	1.87%	1.40
2020Q1	5.46234	5.44002	0.02232	0.41%	0.32
2020Q2	4.96438	5.04554	-0.08115	-1.63%	(1.15)
2020Q3	4.77554	4.78044	-0.00491	-0.10%	(0.07)
2020Q4	5.06822	5.00448	0.06374	1.26%	0.90
2021Q1	5.4519	5.56468	-0.11278	-2.07%	(1.60)
2021Q2	5.15126	5.16309	-0.01183	-0.23%	(0.17)
2021Q3	4.9714	4.90777	0.06362	1.28%	0.90
2021Q4	5.32785	5.31848	0.00937	0.18%	0.13
2022Q1	5.75161	5.76098	-0.00937	-0.16%	(0.13)
2022Q2	5.24701	5.1794	0.06762	1.29%	0.96
2022Q3	4.86939	4.91277	-0.04338	-0.89%	(0.61)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	5.327852	5.145455	0.18	3.4%
Q1 2022	5.751611	5.590818	0.16	2.8%
Q2 2022	5.247014	5.168149	0.08	1.5%
Q3 2022	4.869395	4.91827	-0.05	-1.0%
Total	21.20	20.82	0.37	1.8%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	6.327021	6.320671	0.00635	0%
LOG_L_HLFNGP_S_ROLL12(-3)	-0.627369	-0.622113	-0.005256	1%
LOG_L_Q1_EDD	0.080666	0.080128	0.000538	1%
LOG_L_Q2_EDD	0.035906	0.033551	0.002355	7%
LOG_L_Q4_EDD	0.030978	0.029971	0.001007	3%
L_D16Q1	-0.242531	-0.245004	0.002473	-1%
L_D21Q4+L_D22Q1	0.171101	0	0.171101	
L_D2020	-0.150312	-0.148433	-0.001879	1%
S_D17Q2	0.154737	0.165905	-0.011168	-7%

HLFUPC Sales Springfield
3. Springfield

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
S_HLF_UPC_SALES	8	0.922	3.165

ARIMA Model Parameters

S_HLF_UPC_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	181.3244	10.870	16.68	0.000
	S_HLFNGP_S_ROLL12(-3)	-5.334746	0.998	-5.34	0.000
	S_Q1_EDD+S_Q2_EDD	0.020666	0.001	16.81	0.000
	S_Q4_EDD	0.014961	0.002	6.27	0.000
	S_D12Q1_D17Q1	-20.46924	3.801	-5.39	0.000
	S_D13Q2	29.47893	10.313	2.86	0.007
	S_D20Q2	-36.05869	10.305	-3.50	0.001
	S_D22Q2	29.18119	10.299	2.83	0.007

Variable	Definition	Explanation	Dummy Variable Support
S_HLFNGP_S_ROLL12(-3)	Rolling 12 quarter natural gas price for high load factor sales customers in Springfield ($2022) lagged three quarters		
S_Q1_EDD+S_Q2_EDD	Effective Degree Days in Springfield in Q1 and Q2		
S_Q4_EDD	Effective Degree Days in Springfield in Q4		
S_D12Q1_D17Q1	Binary variable equal to 1 from 2012Q1 to 2017Q1		1
S_D13Q2	Binary variable equal to 1 in 2013Q2		2
S_D20Q2	Binary variable equal to 1 in 2020Q2		2
S_D22Q2	Binary variable equal to 1 in 2022Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

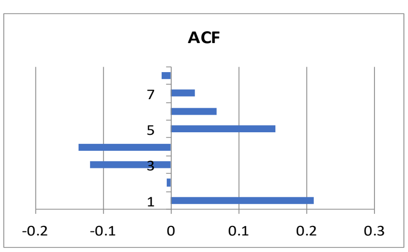
N	Adjusted R2	F Statistic
46	0.907676	64.20226

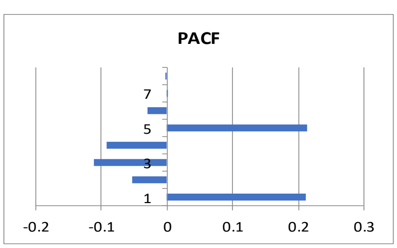
Chow Test Stats	N	k	SSR
Combined	46	8	3,813.11
1	21	6	493.79
2	25	7	3,064.54

Chow Stat:	0.269
P-Value:	0.971375

Heteroscedasticity - White's Test	
White Stat	2.00
Significance (p-value)	0.08

Correlations	S_HLFNGP_S_ROLL12(-3)	S_Q1_EDD+S_Q2_EDD	S_Q4_EDD	S_D12Q1_D17Q1	S_D13Q2	S_D20Q2	S_D22Q2
S_HLFNGP_S_ROLL12(-3)	1	-0.04423	-0.027105	0.599232	0.10151	-0.138118	-0.12644
S_Q1_EDD+S_Q2_EDD	-0.04423	1	-0.454049	0.077991	0.008533	0.028551	0.008792
S_Q4_EDD	-0.027105	-0.454049	1	-0.005109	-0.08319	-0.083189	-0.08319
S_D12Q1_D17Q1	0.599232	0.077991	-0.005109	1	0.16265	-0.136626	-0.13663
S_D13Q2	0.10151	0.008533	-0.083189	0.16265	1	-0.022222	-0.02222
S_D20Q2	-0.138118	0.028551	-0.083189	-0.136626	-0.02222	1	-0.02222
S_D22Q2	-0.126439	0.008792	-0.083189	-0.136626	-0.02222	-0.022222	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_hlf_upc_sales	ACF	0.211	-0.007	-0.119	-0.137	0.155	0.067	0.035	-0.014
	SE	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_hlf_upc_sales		0.211	-0.054	-0.111	-0.093	0.213	-0.029	0.002	-0.002
	SE	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2011Q2	123.472	123.524	-0.05213	-0.04%	(0.01)
2011Q3	101.711	99.9738	1.73702	1.71%	0.17
2011Q4	119.188	122.962	-3.77364	-3.17%	(0.38)
2012Q1	149.282	143.691	5.59193	3.75%	0.56
2012Q2	109.508	105.63	3.87861	3.54%	0.39
2012Q3	87.6525	90.1095	-2.45702	-2.80%	(0.25)
2012Q4	107.484	116.758	-9.27406	-8.63%	(0.93)
2013Q1	159.931	163.831	-3.90038	-2.44%	(0.39)
2013Q2	148.389	148.389	-2.1E-14	0.00%	(0.00)
2013Q3	96.8483	94.6702	2.17818	2.25%	0.22
2013Q4	124.893	123.393	1.50001	1.20%	0.15
2014Q1	171.229	175.691	-4.46205	-2.61%	(0.45)
2014Q2	116.877	121.33	-4.45287	-3.81%	(0.44)
2014Q3	92.956	97.2772	-4.32127	-4.65%	(0.43)
2014Q4	114.332	121.568	-7.23667	-6.33%	(0.72)
2015Q1	188.261	177.182	11.0792	5.89%	1.11
2015Q2	119.051	119.347	-0.29647	-0.25%	(0.03)
2015Q3	100.892	95.2762	5.61584	5.57%	0.56
2015Q4	117.559	115.73	1.82908	1.56%	0.18
2016Q1	145.192	156.713	-11.5206	-7.93%	(1.15)
2016Q2	115.993	119.229	-3.23602	-2.79%	(0.32)
2016Q3	104.735	96.5293	8.20528	7.83%	0.82
2016Q4	124.354	123.044	1.30968	1.05%	0.13
2017Q1	176.224	166.254	9.96962	5.66%	1.00
2017Q2	155.115	148.685	6.43027	4.15%	0.64
2017Q3	127.353	124.45	2.90302	2.28%	0.29
2017Q4	162.611	149.554	13.0572	8.03%	1.30
2018Q1	202.347	204.097	-1.74969	-0.86%	(0.17)
2018Q2	178.927	159.473	19.4541	10.87%	1.94
2018Q3	155.769	134.907	20.8622	13.39%	2.08
2018Q4	162.527	164.074	-1.54691	-0.95%	(0.15)
2019Q1	188.559	206.981	-18.422	-9.77%	(1.84)
2019Q2	145.641	157.302	-11.6604	-8.01%	(1.16)
2019Q3	131.537	134.449	-2.91169	-2.21%	(0.29)
2019Q4	165.007	158.839	6.16737	3.74%	0.62
2020Q1	198.77	194.8	3.96954	2.00%	0.40
2020Q2	123.222	123.222	-5E-14	0.00%	(0.00)
2020Q3	105.101	130.637	-25.5367	-24.30%	(2.55)
2020Q4	158.304	155.539	2.76496	1.75%	0.28
2021Q1	190.713	199.297	-8.58453	-4.50%	(0.86)
2021Q2	135.439	153.18	-17.7415	-13.10%	(1.77)
2021Q3	125.881	128.746	-2.86569	-2.28%	(0.29)
2021Q4	150.423	154.865	-4.4424	-2.95%	(0.44)
2022Q1	220.971	201.021	19.9498	9.03%	1.99
2022Q2	183.926	183.926	-3.9E-14	0.00%	(0.00)
2022Q3	130.944	128.952	1.99189	1.52%	0.20

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2021	150.4229	154.7362	-4.31	-2.9%
Q1 2022	220.9707	198.548	22.42	10.1%
Q2 2022	183.926	153.582	30.34	16.5%
Q3 2022	130.944	128.5149	2.43	1.9%
Total	686.26	635.38	50.88	7.4%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	181.3244	179.8542	1.4702	1%
S_HLFNGP_S_ROLL12(-3)	-5.334746	-5.229521	-0.105225	2%
S_Q1_EDD+S_Q2_EDD	0.020666	0.020077	0.000589	3%
S_Q4_EDD	0.014961	0.015159	-0.000198	-1%
S_D12Q1_D17Q1	-20.46924	-19.66216	-0.80708	4%
S_D13Q2	29.47893	29.53121	-0.05228	0%
S_D20Q2	-36.05869	-34.77342	-1.28527	4%
S_D22Q2	29.18119	0	29.18119	100%

Appendix 5: Billing Cycle Effective Degree Days (EDD)

In any given billing month, billed usage will include usage for customers whose bills were sent out at the beginning of the month, during the month, and at the end of the month. But bills sent out at the beginning of the month represent usage that mostly occurred in the prior month. Bills sent at the end of the month represent usage that mostly occurred within the current month. Analogously, EDD's that occur at the beginning of the month are more likely to affect the current billing month; EDD's at the end of the month are more likely to affect future billing months.

For its forecasting, the Company needs to align its billing month usage with the effective degree days ("EDDs") related to that usage: billing period EDDs. The Company makes this calculation using 2 data sources. The first is meter reading schedules, and the second daily NOAA weather data purchased for each of the Company's three divisions from a weather consulting firm. The main tool is a program that allocates actual daily EDD's into the billing months in which those EDD's were most represented.

For example, consider January 1st, 2007. We examine all the bills that covered a billing period that included 01/01/07. It turns out that about 95% of those bills were sent out in January. The other 5% of bills were sent out in February. We use these percentages to allocate the EDD's that occurred on 01/01/07 into the 2 billing months: 95% of that day's EDD's will be grouped into January billed EDD's, while 5% will be grouped with February. The intuition is clear: the EDD's on 01/01/07 had a 95% chance of affecting January 2007 billed volumes and a 5% chance of affecting February 2007 billed volumes.

We repeat this process for every day in the history and carry the historical billing patterns into the forecast in order to produce our history and forecast of billing period EDD's.

APPENDIX 6: CALCULATION OF NATURAL GAS PRICES

Because economic theory suggests that price is likely to influence demand, an appropriate natural gas price variable that reflects the price that EGMA Gas customers pay for natural gas was developed to be tested in the use per customer models. Historical natural gas prices were developed from Company data by dividing quarterly revenues by quarterly volumes for firm sales customers for each Customer Segment (residential heating, residential non-heating, low load factor, and high load factor) and for each division (Brockton, Lawrence, and Springfield). The calculated prices represent the full delivered cost to customers for gas service "at the burnertip," i.e., delivery and fuel charge. All nominal historical prices were converted to real 2020 dollars using the relevant consumer price indexes ("CPIs") from Moody's Analytics.

Forecasted natural gas prices were developed using a combination of: (1) the Department of Energy, Energy Information Administration's ("DOE-EIA") Short Term Energy Outlook ("STEO"),[1] which provides approximately one year of quarterly forecasts and (2) DOE-EIA's Annual Energy Outlook 2023 with Projections to 2052 ("AEO").[2] The STEO and AEO both provide region-specific natural gas price forecasts for residential, commercial, and industrial customer classes. To develop forecasted customer class gas prices, data for the New England region were used. For each division, a weighted average annual growth rate based on the New England residential, commercial and industrial long-term price forecasts from the AEO were applied to all customer segments; New England class-specific shapes were developed from the STEO (residential STEO data was used to develop price shapes for the residential heating and residential non-heating customer segments, commercial and industrial STEO data was used to develop price shapes for the C&I LLF and C&I HLF Customer Segments, respectively).

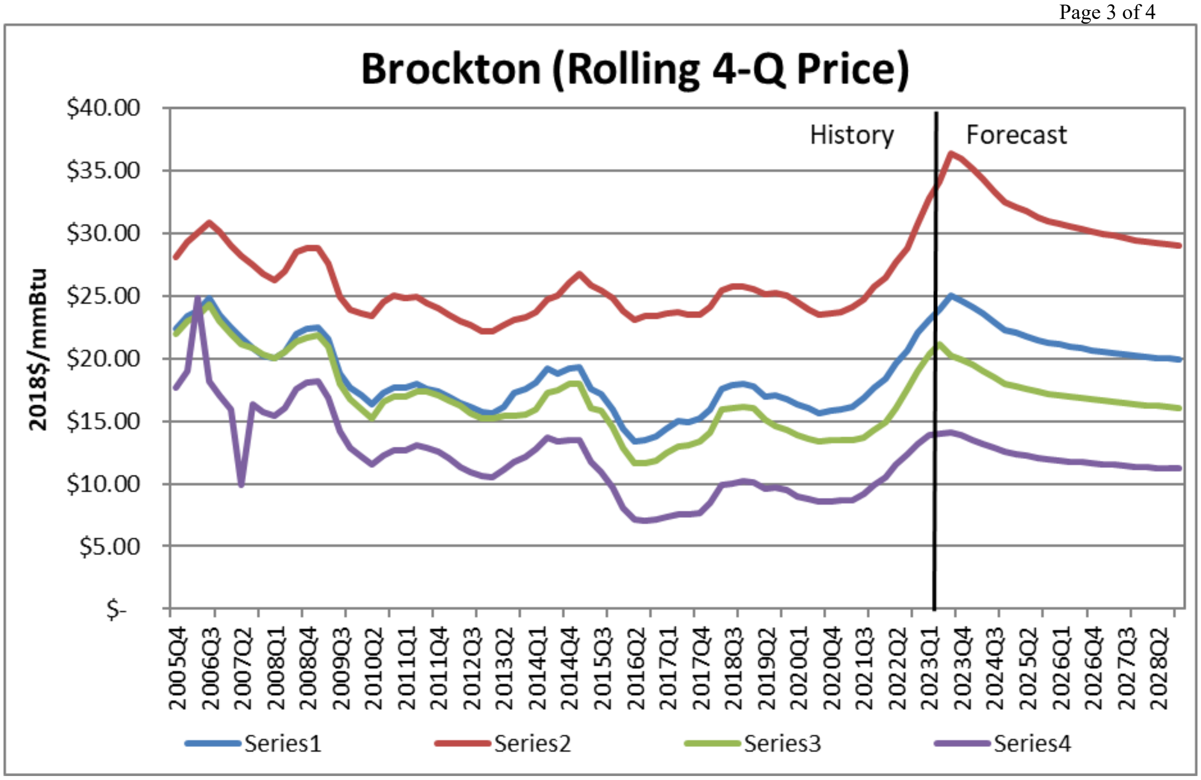
To develop forecasted gas prices that were calibrated to the EGMA Gas service territories, percent changes in the STEO and AEO prices throughout the forecast period were applied to the

1 Dated April 2023.
2 Dated February 2023.

base period or forecast period Company prices. Specifically, the AEO weighted average annual percent change was applied to the Company-specific historical gas prices to develop the forecast annual natural gas price levels through 2026. A quarterly shape for the forecast period was developed by Customer Segment and division using the STEO quarterly price forecast and applied to the forecast annual natural gas prices to develop a quarterly shape for the 2022 Q4 through 2028 price forecast.

The price variable that was used in the use per customer models was determined by calculating volume-weighted, rolling four quarter averages from the actual and forecasted quarterly natural gas price data. The price variable reflects the concept that gas equipment purchases and changes in gas usage behavior are customer decisions that occur over an extended twelve month period.[3] The following graphs illustrate the historical and forecast data for the rolling four quarters price variables that were used in the use per customer models.

3 A price variable that is calculated as rolling four quarter averages also avoids a statistical problem with data known as "simultaneity," which occurs when two variables have an effect on each other at the same time. For example, the price of gas service, measured as average revenues per therm may be generally higher in the summer, and lower in the winter because of the impact of fixed customer charges on the average rate, divided by low delivery quantities in the summer and high delivery quantities in the winter. Simultaneity occurs because in this example, a high price did not cause low usage; rather, a high price was caused by low usage.


Brockton (Rolling 4-Q Price)
History
Forecast
2018$/mmBtu
$40.00
$35.00
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$-
2005Q4
2006Q3
2007Q2
2008Q1
2008Q4
2009Q3
2010Q2
2011Q1
2011Q4
2012Q3
2013Q2
2014Q1
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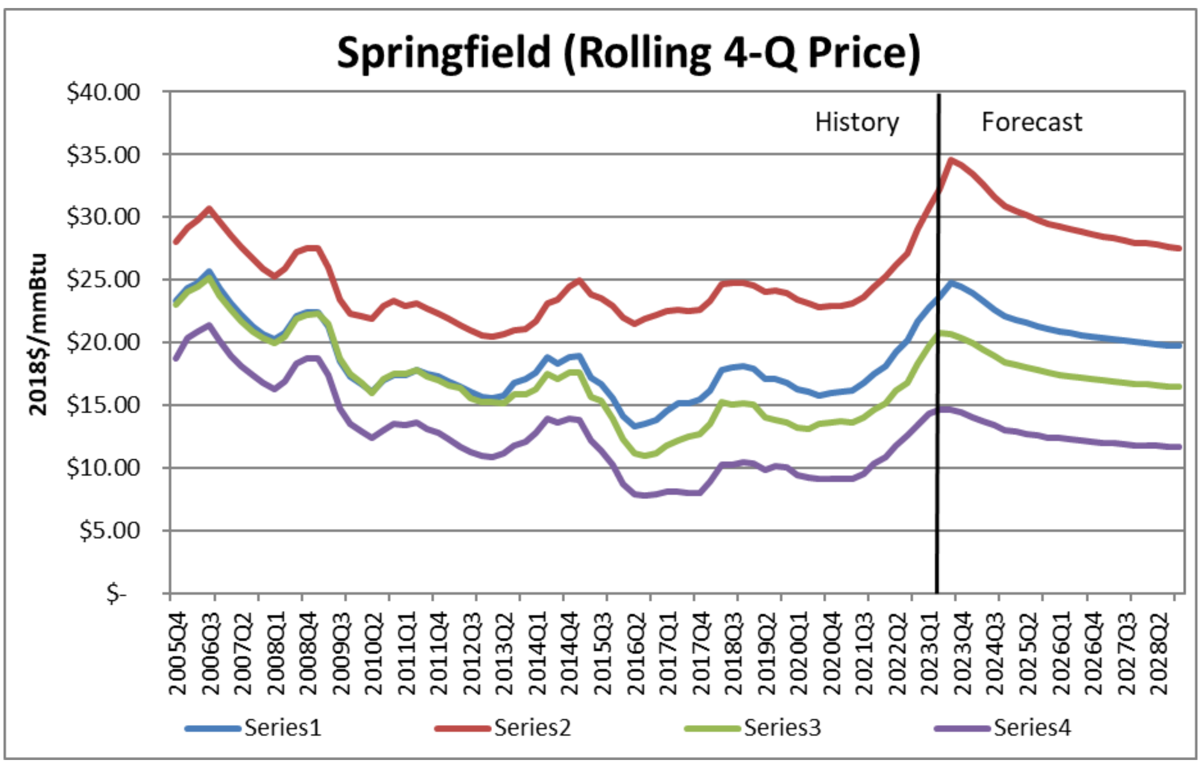
Series1
Series2
Series3
Series4


Springfield (Rolling 4-Q Price)
History
Forecast
2018$/mmBtu
$40.00
$35.00
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$-
2005Q4
2006Q3
2007Q2
2008Q1
2008Q4
2009Q3
2010Q2
2011Q1
2011Q4
2012Q3
2013Q2
2014Q1
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2021Q3
2022Q2
2023Q1
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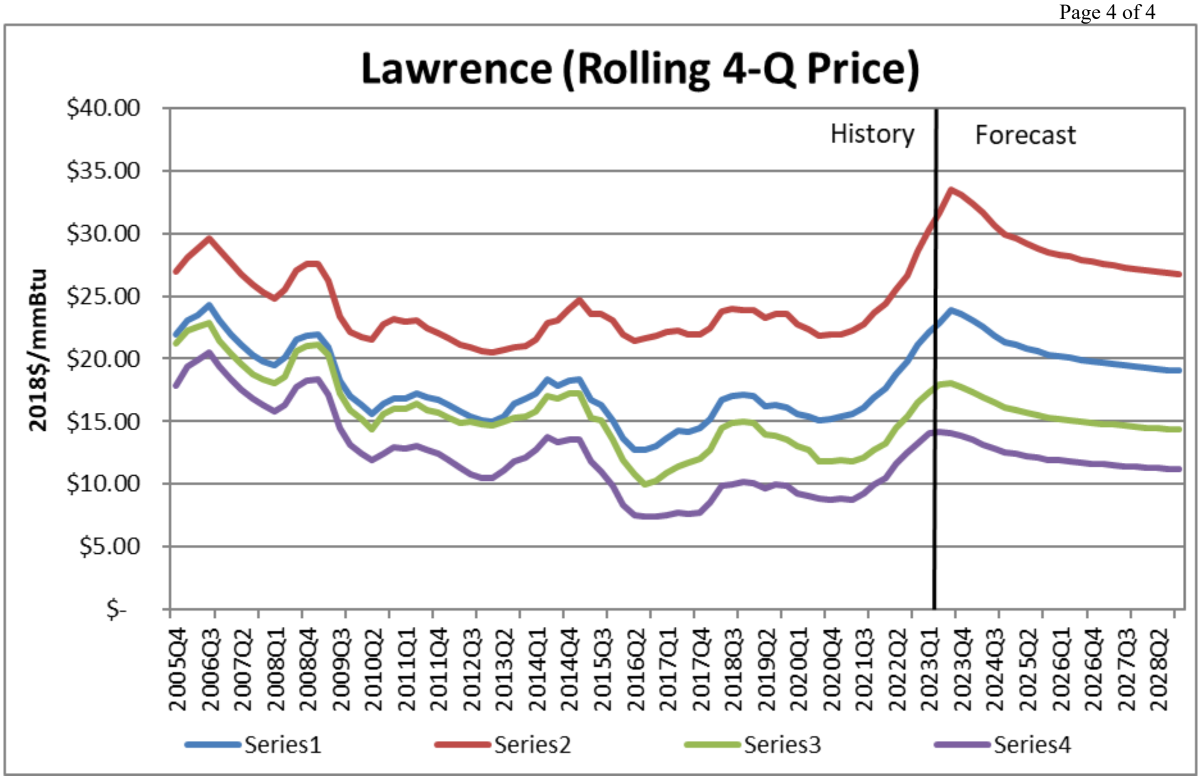
Series1
Series2
Series3
Series4



Additional variables based on natural gas prices were developed for testing in the customer count models. Economic theory suggests that fuel switching from oil to natural gas depends on the relative prices of the two fuels and the savings to be realized from fuel switching. Two variables were developed to measure those economic factors. A natural gas to oil price ratio variable was developed for each division and Customer Segment. This variable was calculated as the ratio of the rolling eight quarter average natural gas price to the rolling eight quarter national average retail price for No. 2 diesel fuel on an energy-equivalent basis.[4] In addition, a variable was developed to estimate the cumulative savings from fuel switching from oil to natural gas. Savings from fuel switching for a given quarter was calculated as the difference between the aforementioned oil and natural gas prices used for the price ratio variable multiplied by the most recent historical quarterly use per customer values by division and Customer Segment.

[4] Moody's Analytics does not forecast heating oil prices specific to the EGMA Gas service territories, so a national average price was used.

Appendix 7: Customer Segment Variable Descriptions[1]

	Variable Name	Description	Geography	Source
1	B_RH_CUST_S_T	Residential Heating Customers	Brockton Division	EGMA Billing System
2	L_RH_CUST_S_T	Residential Heating Customers	Lawrence Division	EGMA Billing System
3	S_RH_CUST_S_T	Residential Heating Customers	Springfield Division	EGMA Billing System
4	B_RNH_CUST_S_T	Residential Non-Heating Customers	Brockton Division	EGMA Billing System
5	L_RNH_CUST_S_T	Residential Non-Heating Customers	Lawrence Division	EGMA Billing System
6	S_RNH_CUST_S_T	Residential Non-Heating Customers	Springfield Division	EGMA Billing System
7	B_LLF_CUST_SALES	Low Load Factor Customers Sales Only	Brockton Division	EGMA Billing System
8	L_LLF_CUST_SALES	Low Load Factor Customers Sales Only	Lawrence Division	EGMA Billing System
9	S_LLF_CUST_SALES	Low Load Factor Customers Sales Only	Springfield Division	EGMA Billing System
10	B_LLF_CUST_S_T	Low Load Factor Customers Sales and Transportation	Brockton Division	EGMA Billing System
11	L_LLF_CUST_S_T	Low Load Factor Customers Sales and Transportation	Lawrence Division	EGMA Billing System
12	S_LLF_CUST_S_T	Low Load Factor Customers Sales and Transportation	Springfield Division	EGMA Billing System
13	B_HLF_CUST_SALES	High Load Factor Customers Sales Only	Brockton Division	EGMA Billing System
14	L_HLF_CUST_SALES	High Load Factor Customers Sales Only	Lawrence Division	EGMA Billing System
15	S_HLF_CUST_SALES	High Load Factor Customers Sales Only	Springfield Division	EGMA Billing System
16	B_HLF_CUST_S_T	High Load Factor Customers Sales and Transportation	Brockton Division	EGMA Billing System
17	L_HLF_CUST_S_T	High Load Factor Customers Sales and Transportation	Lawrence Division	EGMA Billing System
18	S_HLF_CUST_S_T	High Load Factor Customers Sales and Transportation	Springfield Division	EGMA Billing System
19	B_RH_UPC_S_T	Residential Heating Use Per Customer	Brockton Division	EGMA Billing System
20	L_RH_UPC_S_T	Residential Heating Use Per Customer	Lawrence Division	EGMA Billing System
21	S_RH_UPC_S_T	Residential Heating Use Per Customer	Springfield Division	EGMA Billing System
22	B_RNH_UPC_S_T	Residential Non-Heating Use Per Customer	Brockton Division	EGMA Billing System
23	L_RNH_UPC_S_T	Residential Non-Heating Use Per Customer	Lawrence Division	EGMA Billing System
24	S_RNH_UPC_S_T	Residential Non-Heating Use Per Customer	Springfield Division	EGMA Billing System
25	B_LLF_UPC_SALES	Low Load Factor Use Per Customer Sales Only	Brockton Division	EGMA Billing System

[1] This appendix shows all of the variables available for testing in the customer and use per customer regression models. It does not list all binary variables and interactive variables developed for specific models; rather those variables are presented in the models' statistical summaries. Some models employed natural log specifications of the variables in this appendix.

	Variable Name	Description	Geography	Source
26	L_LLF_UPC_SALES	Low Load Factor Use Per Customer Sales Only	Lawrence Division	EGMA Billing System
27	S_LLF_UPC_SALES	Low Load Factor Use Per Customer Sales Only	Springfield Division	EGMA Billing System
28	B_LLF_UPC_S_T	Low Load Factor Use Per Customer Sales and Transportation	Brockton Division	EGMA Billing System
29	L_LLF_UPC_S_T	Low Load Factor Use Per Customer Sales and Transportation	Lawrence Division	EGMA Billing System
30	S_LLF_UPC_S_T	Low Load Factor Use Per Customer Sales and Transportation	Springfield Division	EGMA Billing System
31	B_HLF_UPC_SALES	High Load Factor Use Per Customer Sales Only	Brockton Division	EGMA Billing System
32	L_HLF_UPC_SALES	High Load Factor Use Per Customer Sales Only	Lawrence Division	EGMA Billing System
33	S_HLF_UPC_SALES	High Load Factor Use Per Customer Sales Only	Springfield Division	EGMA Billing System
34	B_HLF_UPC_S_T	High Load Factor Use Per Customer Sales and Transportation	Brockton Division	EGMA Billing System
35	L_HLF_UPC_S_T	High Load Factor Use Per Customer Sales and Transportation	Lawrence Division	EGMA Billing System
36	S_HLF_UPC_S_T	High Load Factor Use Per Customer Sales and Transportation	Springfield Division	EGMA Billing System
37	TREND	Quarterly Trend	NA	NA
38	Q1	Quarter 1 Binary Variable	NA	NA
39	Q2	Quarter 2 Binary Variable	NA	NA
40	Q3	Quarter 3 Binary Variable	NA	NA
41	Q4	Quarter 4 Binary Variable	NA	NA
42	B_RHNGP	Residential Heating Natural Gas Price	Brockton Division	EGMA Billing System; U.S. DOE-EIA
43	L_RHNGP	Residential Heating Natural Gas Price	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
44	S_RHNGP	Residential Heating Natural Gas Price	Springfield Division	EGMA Billing System; U.S. DOE-EIA
45	B_RRNGP	Residential Non-Heating Natural Gas Price	Brockton Division	EGMA Billing System; U.S. DOE-EIA
46	L_RRNGP	Residential Non-Heating Natural Gas Price	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
47	S_RRNGP	Residential Non-Heating Natural Gas Price	Springfield Division	EGMA Billing System; U.S. DOE-EIA
48	B_LLFNGP_S	Low Load Factor Natural Gas Price Sales Only	Brockton Division	EGMA Billing System; U.S. DOE-EIA
49	L_LLFNGP_S	Low Load Factor Natural Gas Price Sales Only	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
50	S_LLFNGP_S	Low Load Factor Natural Gas Price Sales Only	Springfield Division	EGMA Billing System; U.S. DOE-EIA
51	B_LLFNGP_ST	Low Load Factor Natural Gas Price Sales and Transportation	Brockton Division	EGMA Billing System; U.S. DOE-EIA

	Variable Name	Description	Geography	Source
52	L_LLFNGP_ST	Low Load Factor Natural Gas Price Sales and Transportation	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
53	S_LLFNGP_ST	Low Load Factor Natural Gas Price Sales and Transportation	Springfield Division	EGMA Billing System; U.S. DOE-EIA
54	B_HLFNGP_S	High Load Factor Natural Gas Price Sales Only	Brockton Division	EGMA Billing System; U.S. DOE-EIA
55	L_HLFNGP_S	High Load Factor Natural Gas Price Sales Only	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
56	S_HLFNGP_S	High Load Factor Natural Gas Price Sales Only	Springfield Division	EGMA Billing System; U.S. DOE-EIA
57	B_HLFNGP_ST	High Load Factor Natural Gas Price Sales and Transportation	Brockton Division	EGMA Billing System; U.S. DOE-EIA
58	L_HLFNGP_ST	High Load Factor Natural Gas Price Sales and Transportation	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
59	S_HLFNGP_ST	High Load Factor Natural Gas Price Sales and Transportation	Springfield Division	EGMA Billing System; U.S. DOE-EIA
60	B_RHNGP_ROLL12	Residential Heating Natural Gas Price Rolling 12 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA
61	L_RHNGP_ROLL12	Residential Heating Natural Gas Price Rolling 12 Quarter	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
62	S_RHNGP_ROLL12	Residential Heating Natural Gas Price Rolling 12 Quarter	Springfield Division	EGMA Billing System; U.S. DOE-EIA
63	B_RRNGP_ROLL12	Residential Non-Heating Natural Gas Price Rolling 12 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA
64	L_RRNGP_ROLL12	Residential Non-Heating Natural Gas Price Rolling 12 Quarter	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
65	S_RRNGP_ROLL12	Residential Non-Heating Natural Gas Price Rolling 12 Quarter	Springfield Division	EGMA Billing System; U.S. DOE-EIA
66	B_LLFNGP_S_ROLL12	Low Load Factor Natural Gas Price Sales Only Rolling 12 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA
67	L_LLFNGP_S_ROLL12	Low Load Factor Natural Gas Price Sales Only Rolling 12 Quarter	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
68	S_LLFNGP_S_ROLL12	Low Load Factor Natural Gas Price Sales Only Rolling 12 Quarter	Springfield Division	EGMA Billing System; U.S. DOE-EIA
69	B_HLFNGP_S_ROLL12	High Load Factor Natural Gas Price Sales Only Rolling 12 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA
70	L_HLFNGP_S_ROLL12	High Load Factor Natural Gas Price Sales Only Rolling 12 Quarter	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
71	S_HLFNGP_S_ROLL12	High Load Factor Natural Gas Price Sales Only Rolling 12 Quarter	Springfield Division	EGMA Billing System; U.S. DOE-EIA
72	B_LLFNGP_ST_ROLL12	Low Load Factor Natural Gas Price Sales and Transportation Rolling 12 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA
73	L_LLFNGP_ST_ROLL12	Low Load Factor Natural Gas Price Sales and Transportation Rolling 12 Quarter	Lawrence Division	EGMA Billing System; U.S. DOE-EIA

	Variable Name	Description	Geography	Source
74	S_LLFNGP_ST_ROLL12	Low Load Factor Natural Gas Price Sales and Transportation Rolling 12 Quarter	Springfield Division	EGMA Billing System; U.S. DOE-EIA
75	B_HLFNGP_ST_ROLL12	High Load Factor Natural Gas Price Sales and Transportation Rolling 12 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA
76	L_HLFNGP_ST_ROLL12	High Load Factor Natural Gas Price Sales and Transportation Rolling 12 Quarter	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
77	S_HLFNGP_ST_ROLL12	High Load Factor Natural Gas Price Sales and Transportation Rolling 12 Quarter	Springfield Division	EGMA Billing System; U.S. DOE-EIA
78	B_RHNGOIL	Residential Heating Natural Gas to Oil Price Ratio	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
79	L_RHNGOIL	Residential Heating Natural Gas to Oil Price Ratio	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
80	S_RHNGOIL	Residential Heating Natural Gas to Oil Price Ratio	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
81	B_RRNGOIL	Residential Non-Heating Natural Gas to Oil Price Ratio	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
82	L_RRNGOIL	Residential Non-Heating Natural Gas to Oil Price Ratio	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
83	S_RRNGOIL	Residential Non-Heating Natural Gas to Oil Price Ratio	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
84	B_LLFNGOIL	Low Load Factor Natural Gas to Oil Price Ratio Rolling 8 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
85	L_LLFNGOIL_S	Low Load Factor Natural Gas to Oil Price Ratio Sales Only	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
86	S_LLFNGOIL_S	Low Load Factor Natural Gas to Oil Price Ratio Sales Only	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
87	B_LLFNGOIL_ST	Low Load Factor Natural Gas to Oil Price Ratio Sales and Transportation	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
88	L_LLFNGOIL_ST	Low Load Factor Natural Gas to Oil Price Ratio Sales and Transportation	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
89	S_LLFNGOIL_ST	Low Load Factor Natural Gas to Oil Price Ratio Sales and Transportation	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
90	B_HLFNGOIL_S	High Load Factor Natural Gas to Oil Price Ratio Sales Only	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
91	L_HLFNGOIL_S	High Load Factor Natural Gas to Oil Price Ratio Sales Only	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's

	Variable Name	Description	Geography	Source
92	S_HLFNGOIL_S	High Load Factor Natural Gas to Oil Price Ratio Sales Only	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
93	B_HLFNGOIL_ST	High Load Factor Natural Gas to Oil Price Ratio Sales and Transportation	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
94	L_HLFNGOIL_ST	High Load Factor Natural Gas to Oil Price Ratio Sales and Transportation	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
95	S_HLFNGOIL_ST	High Load Factor Natural Gas to Oil Price Ratio Sales and Transportation	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
96	B_RHOIL_NG_SAVE	Residential Heating Cumulative Savings from Fuel Switching	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
97	L_RHOIL_NG_SAVE	Residential Heating Cumulative Savings from Fuel Switching	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
98	S_RHOIL_NG_SAVE	Residential Heating Cumulative Savings from Fuel Switching	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
99	B_RROIL_NG_SAVE	Residential Non-Heating Cumulative Savings from Fuel Switching	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
100	L_RROIL_NG_SAVE	Residential Non-Heating Cumulative Savings from Fuel Switching	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
101	S_RROIL_NG_SAVE	Residential Non-Heating Cumulative Savings from Fuel Switching	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
102	B_LLFOIL_NG_SAVE_S	Low Load Factor Cumulative Savings from Fuel Switching Sales Only	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
103	L_LLFOIL_NG_SAVE_S	Low Load Factor Cumulative Savings from Fuel Switching Sales Only	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
104	S_LLFOIL_NG_SAVE_S	Low Load Factor Cumulative Savings from Fuel Switching Sales Only	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
105	B_LLFOIL_NG_SAVE_ST	Low Load Factor Cumulative Savings from Fuel Switching Sales and Transportation	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
106	L_LLFOIL_NG_SAVE_ST	Low Load Factor Cumulative Savings from Fuel Switching Sales and Transportation	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
107	S_LLFOIL_NG_SAVE_ST	Low Load Factor Cumulative Savings from Fuel Switching Sales and Transportation	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
108	B_HLFOIL_NG_SAVE_S	High Load Factor Cumulative Savings from Fuel Switching Sales Only	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
109	L_HLFOIL_NG_SAVE_S	High Load Factor Cumulative Savings from Fuel Switching Sales Only	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's

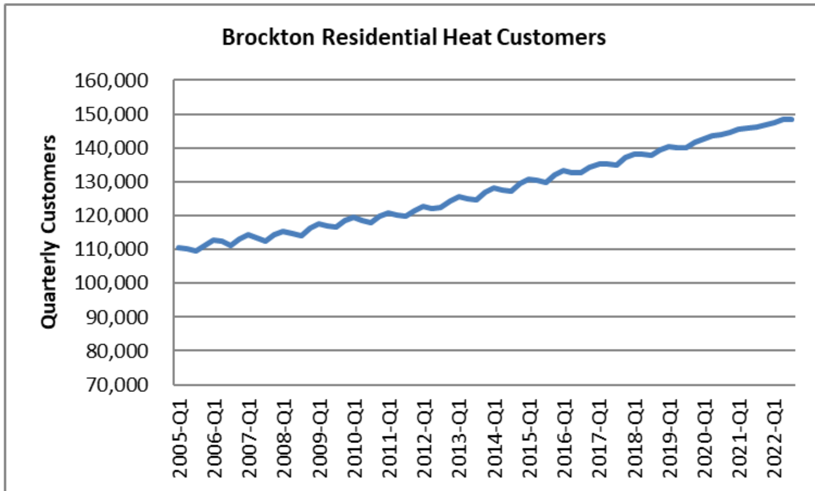
	Variable Name	Description	Geography	Source
110	S_HLFOIL_NG_SAVE_S	High Load Factor Cumulative Savings from Fuel Switching Sales Only	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
112	B_HLFOIL_NG_SAVE_ST	High Load Factor Cumulative Savings from Fuel Switching Sales and Transportation	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
113	L_HLFOIL_NG_SAVE_ST	High Load Factor Cumulative Savings from Fuel Switching Sales and Transportation	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
114	S_HLFOIL_NG_SAVE_ST	High Load Factor Cumulative Savings from Fuel Switching Sales and Transportation	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
115	B_EDD	Billing Cycle Effective Degree Days	Brockton Division	U.S Weather Bureau (Bedford, MA-Providence RI)
116	L_EDD	Billing Cycle Effective Degree Days	Lawrence Division	U.S Weather Bureau (Bedford, MA – Portsmouth, NH)
117	S_EDD	Billing Cycle Effective Degree Days	Springfield Division	U.S. Weather Bureau (Windsor Locks, CT)
118	B_Q1_EDD	Billing Cycle Effective Degree Days in Quarter 1	Brockton Division	U.S Weather Bureau (Bedford, MA-Providence RI)
119	B_Q2_EDD	Billing Cycle Effective Degree Days in Quarter 2	Brockton Division	U.S Weather Bureau (Bedford, MA-Providence RI)
120	B_Q3_EDD	Billing Cycle Effective Degree Days in Quarter 3	Brockton Division	U.S Weather Bureau (Bedford, MA-Providence RI)
121	B_Q4_EDD	Billing Cycle Effective Degree Days in Quarter 4	Brockton Division	U.S Weather Bureau (Bedford, MA-Providence RI)
122	B_Q2_4_EDD	Billing Cycle Effective Degree Days in Quarters 2 and 4	Brockton Division	U.S Weather Bureau (Bedford, MA-Providence RI)
123	L_Q1_EDD	Billing Cycle Effective Degree Days in Quarter 1	Lawrence Division	U.S Weather Bureau (Bedford, MA – Portsmouth, NH)
124	L_Q2_EDD	Billing Cycle Effective Degree Days in Quarter 2	Lawrence Division	U.S Weather Bureau (Bedford, MA – Portsmouth, NH)
125	L_Q3_EDD	Billing Cycle Effective Degree Days in Quarter 3	Lawrence Division	U.S Weather Bureau (Bedford, MA – Portsmouth, NH)
126	L_Q4_EDD	Billing Cycle Effective Degree Days in Quarter 4	Lawrence Division	U.S Weather Bureau (Bedford, MA – Portsmouth, NH)
127	L_Q2_4_EDD	Billing Cycle Effective Degree Days in Quarters 2 and 4	Lawrence Division	U.S Weather Bureau (Bedford, MA – Portsmouth, NH)
128	S_Q1_EDD	Billing Cycle Effective Degree Days in Quarter 1	Springfield Division	U.S. Weather Bureau (Windsor Locks, CT)
129	S_Q2_EDD	Billing Cycle Effective Degree Days in Quarter 2	Springfield Division	U.S. Weather Bureau (Windsor Locks, CT)

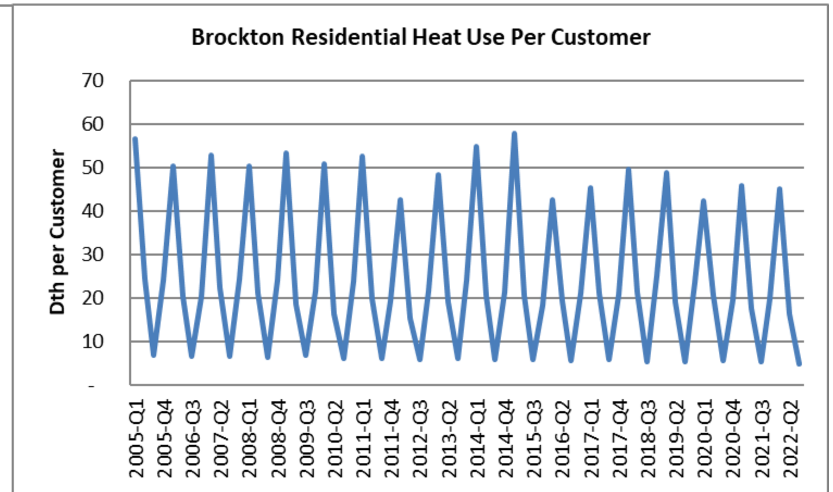
	Variable Name	Description	Geography	Source
130	S_Q3_EDD	Billing Cycle Effective Degree Days in Quarter 3	Springfield Division	U.S. Weather Bureau (Windsor Locks, CT)
131	S_Q4_EDD	Billing Cycle Effective Degree Days in Quarter 4	Springfield Division	U.S. Weather Bureau (Windsor Locks, CT)
132	S_Q2_4_EDD	Billing Cycle Effective Degree Days in Quarters 2 and 4	Springfield Division	U.S. Weather Bureau (Windsor Locks, CT)
133	B_POP	Population (thousands)	Brockton Division	Moody's Economy.com
134	L_POP	Population (thousands)	Lawrence Division	Moody's Economy.com
135	S_POP	Population (thousands)	Springfield Division	Moody's Economy.com
136	B_HH	Households (thousands)	Brockton Division	Moody's Economy.com
137	L_HH	Households (thousands)	Lawrence Division	Moody's Economy.com
138	S_HH	Households (thousands)	Springfield Division	Moody's Economy.com
139	B_HC_MULTI	Multi-Family Housing Completions (# of units)	Brockton Division	Moody's Economy.com
140	L_HC_MULTI	Multi-Family Housing Completions (# of units)	Lawrence Division	Moody's Economy.com
141	S_HC_MULTI	Multi-Family Housing Completions (# of units)	Springfield Division	Moody's Economy.com
142	B_HC_SINGLE	Single-Family Housing Completions (# of units)	Brockton Division	Moody's Economy.com
143	L_HC_SINGLE	Single-Family Housing Completions (# of units)	Lawrence Division	Moody's Economy.com
144	S_HC_SINGLE	Single-Family Housing Completions (# of units)	Springfield Division	Moody's Economy.com
145	B_CUMULATIVE_HC	Cumulative Housing Completions (# of units)	Brockton Division	Moody's Economy.com
146	L_CUMULATIVE_HC	Cumulative Housing Completions (# of units)	Lawrence Division	Moody's Economy.com
147	S_CUMULATIVE_HC	Cumulative Housing Completions (# of units)	Springfield Division	Moody's Economy.com
148	B_MEAN_HH_INC	Average Household Income ($)	Brockton Division	Moody's Economy.com
149	L_MEAN_HH_INC	Average Household Income ($)	Lawrence Division	Moody's Economy.com
150	S_MEAN_HH_INC	Average Household Income ($)	Springfield Division	Moody's Economy.com
151	B_PINC	Total Personal Income (million $2012)	Brockton Division	Moody's Economy.com
152	L_PINC	Total Personal Income (million $2012)	Lawrence Division	Moody's Economy.com
153	S_PINC	Total Personal Income (million $2012)	Springfield Division	Moody's Economy.com
154	B_GMP	Gross Metro Product (billion $)	Brockton Division	Moody's Economy.com
155	L_GMP	Gross Metro Product (billion $)	Lawrence Division	Moody's Economy.com
156	S_GMP	Gross Metro Product (billion $)	Springfield Division	Moody's Economy.com
157	B_GMP_CHAIN	Gross Metro Product (billion $)	Brockton Division	Moody's Economy.com
158	L_GMP_CHAIN	Gross Metro Product (billion chained 2012 $)	Lawrence Division	Moody's Economy.com
159	S_GMP_CHAIN	Gross Metro Product (billion chained 2012 $)	Springfield Division	Moody's Economy.com
160	B_EMPLOY	Non-Farm Employment (thousands)	Brockton Division	Moody's Economy.com
161	L_EMPLOY	Non-Farm Employment (thousands)	Lawrence Division	Moody's Economy.com

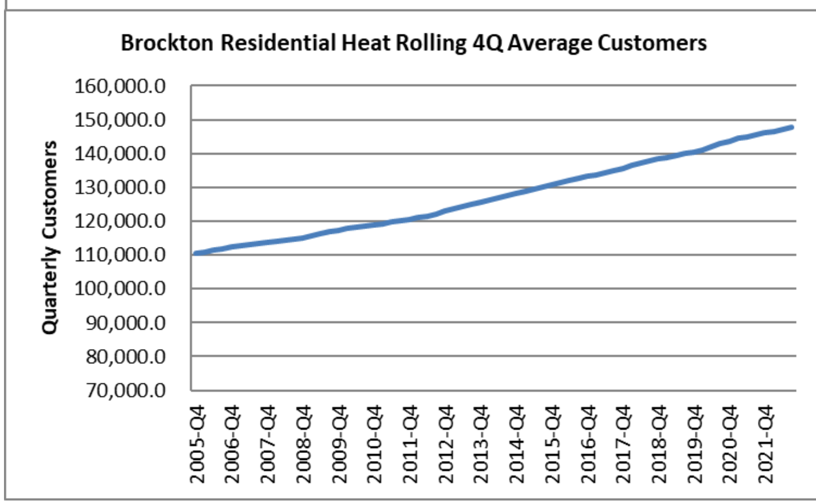
	Variable Name	Description	Geography	Source
162	S_EMPLOY	Non-Farm Employment (thousands)	Springfield Division	Moody’s Economy.com
163	B_MFG_EMPLOY	Manufacturing Employment (thousands)	Brockton Division	Moody’s Economy.com
164	L_MFG_EMOLOY	Manufacturing Employment (thousands)	Lawrence Division	Moody’s Economy.com
165	S_MFG_EMPLOY	Manufacturing Employment (thousands)	Springfield Division	Moody’s Economy.com
166	B_NON_MFG_EMPLOY	Non-Manufacturing Employment (thousands)	Brockton Division	Moody’s Economy.com
167	L_NON_MFG_EMPLOY	Non-Manufacturing Employment (thousands)	Lawrence Division	Moody’s Economy.com
168	S_NON_MFG_EMPLOY	Non-Manufacturing Employment (thousands)	Springfield Division	Moody’s Economy.com

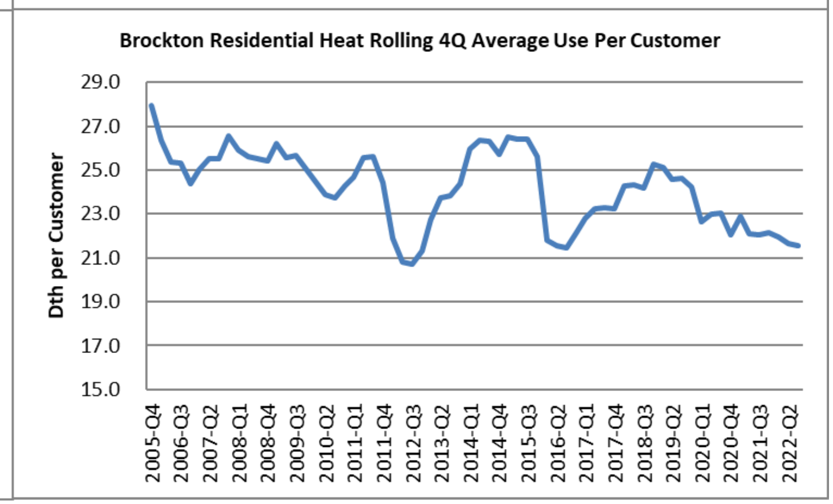
Appendix 8: Dependent Variable Graphs

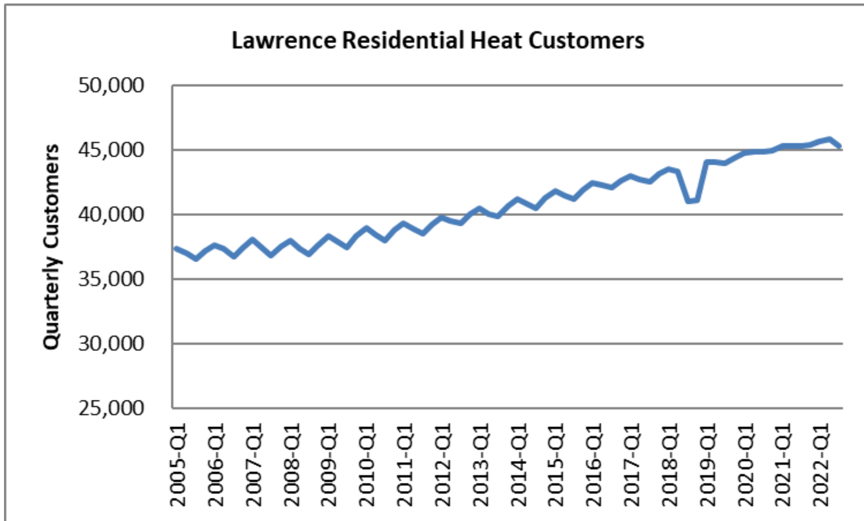
Sales and Transportation Combined:

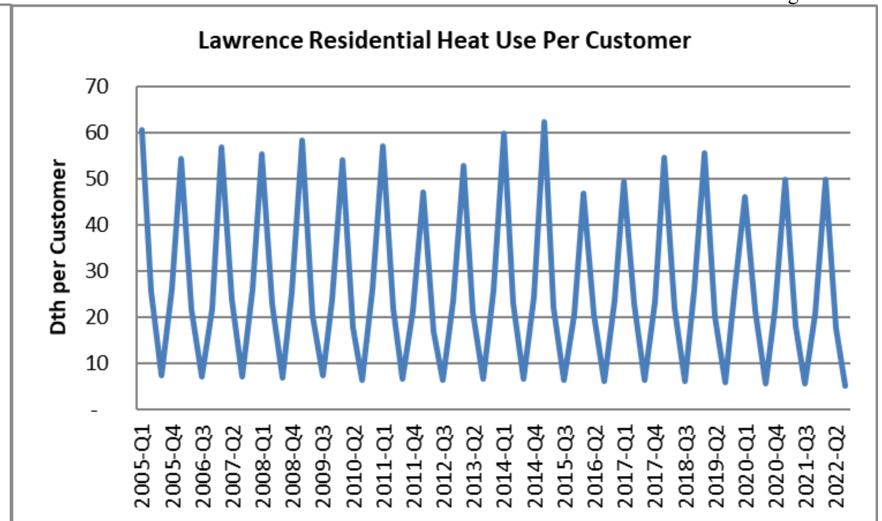


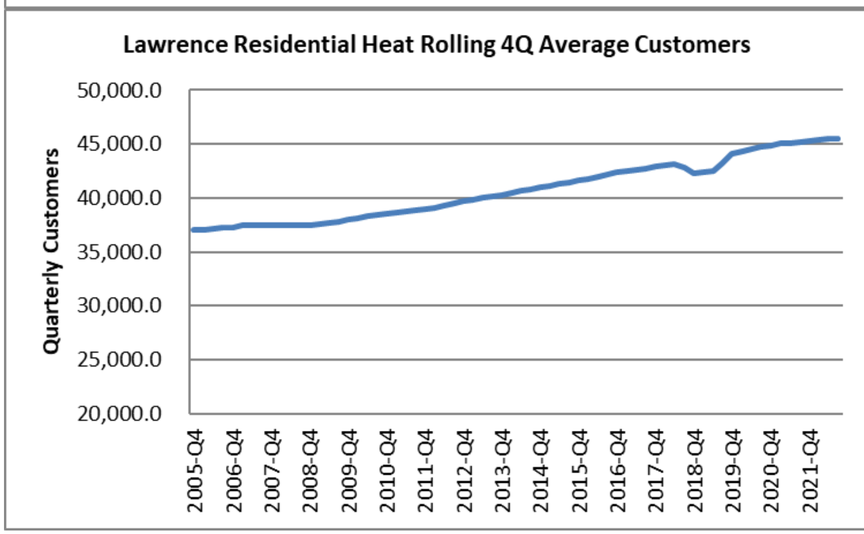







Lawrence Residential Heat Customers
Quarterly Customers
50,000
45,000
40,000
35,000
30,000
25,000
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1


Lawrence Residential Heat Use Per Customer
Dth per Customer
70
60
50
40
30
20
10
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2


Lawrence Residential Heat Rolling 4Q Average Customers
Quarterly Customers
50,000.0
45,000.0
40,000.0
35,000.0
30,000.0
25,000.0
20,000.0
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
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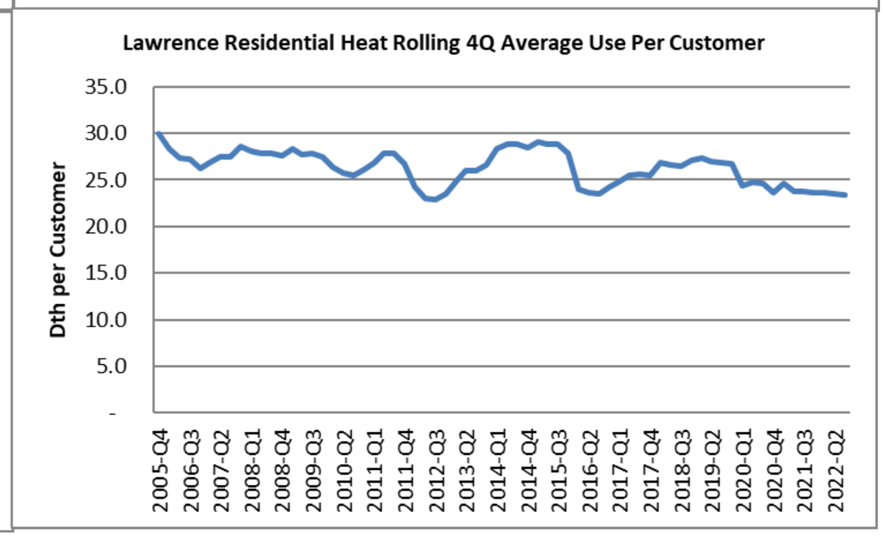
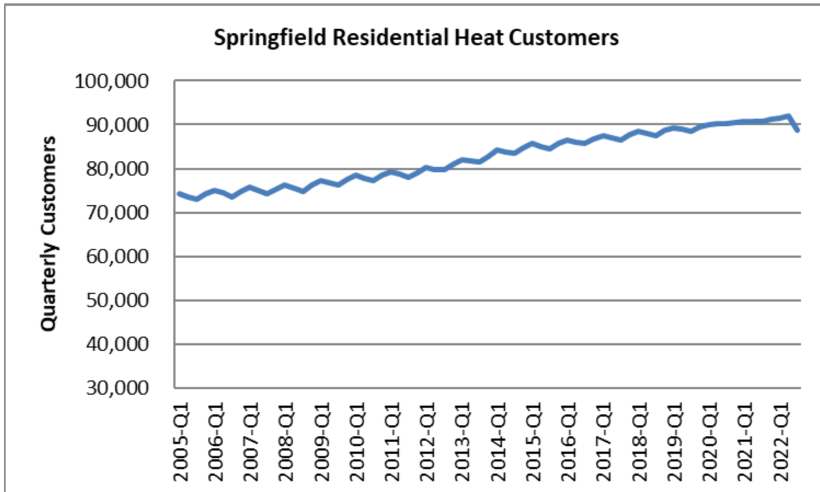
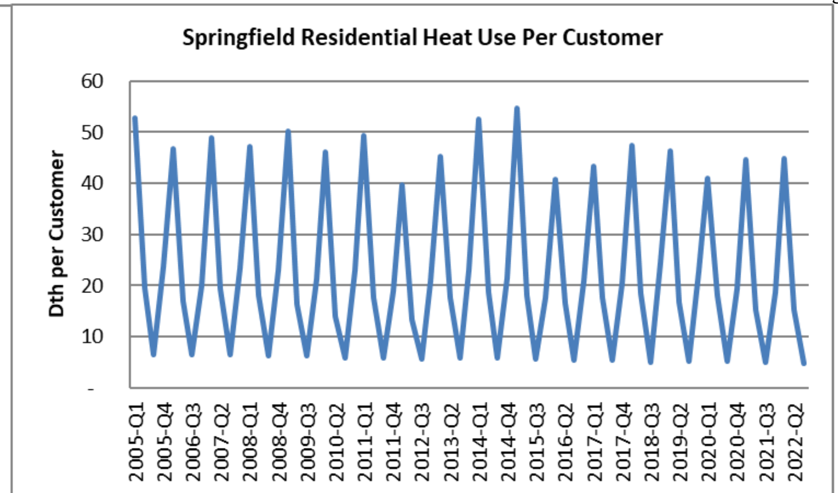
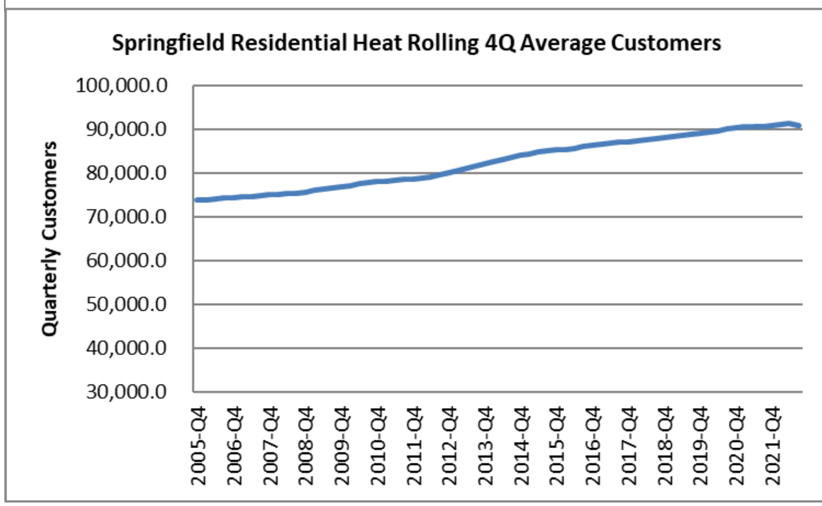
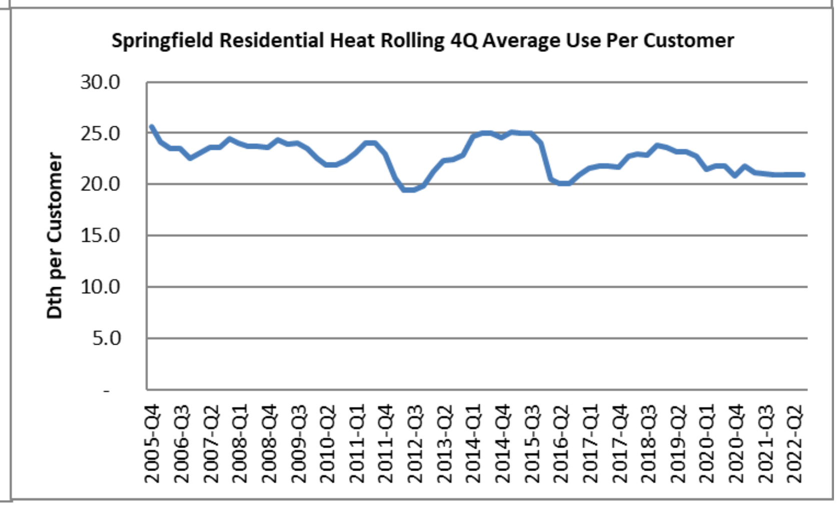
2018-Q4
2019-Q4
2020-Q4
2021-Q4

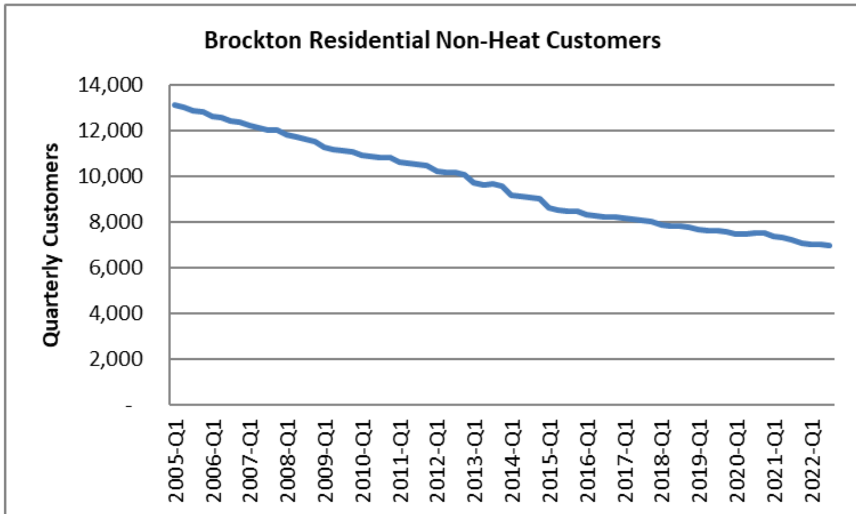

Lawrence Residential Heat Rolling 4Q Average Use Per Customer
Dth per Customer
35.0
30.0
25.0
20.0
15.0
10.0
5.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

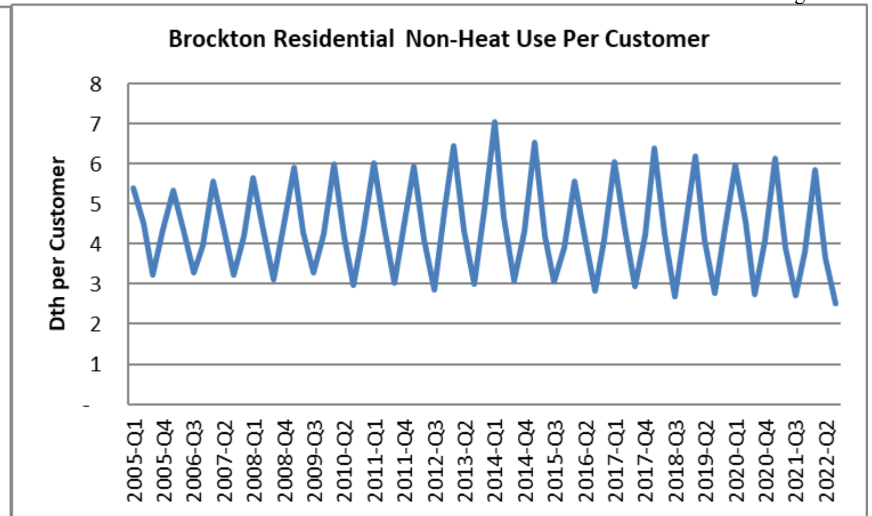

Springfield Residential Heat Customers
Quarterly Customers
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

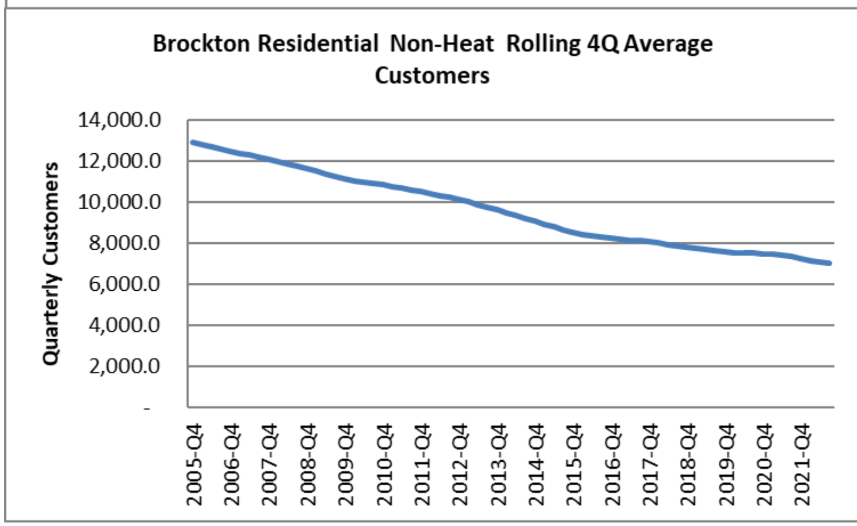

Springfield Residential Heat Use Per Customer
Dth per Customer
60
50
40
30
20
10
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

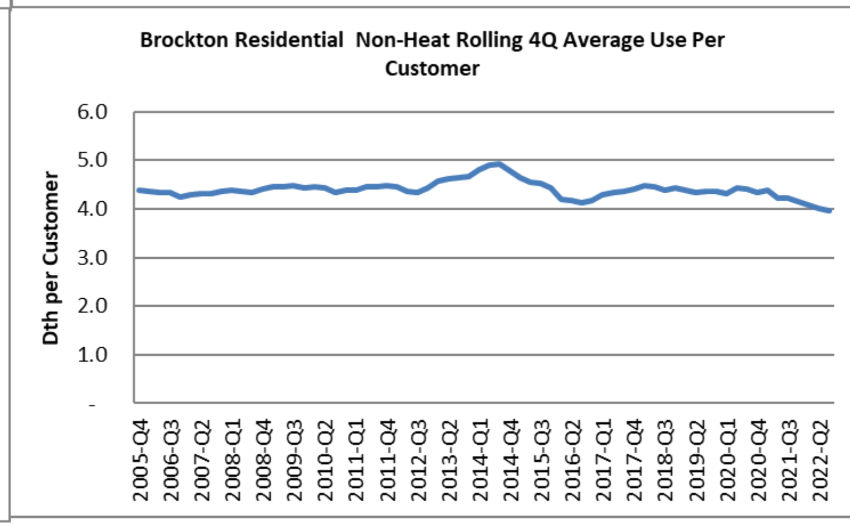

Springfield Residential Heat Rolling 4Q Average Customers
Quarterly Customers
100,000.0
90,000.0
80,000.0
70,000.0
60,000.0
50,000.0
40,000.0
30,000.0
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4

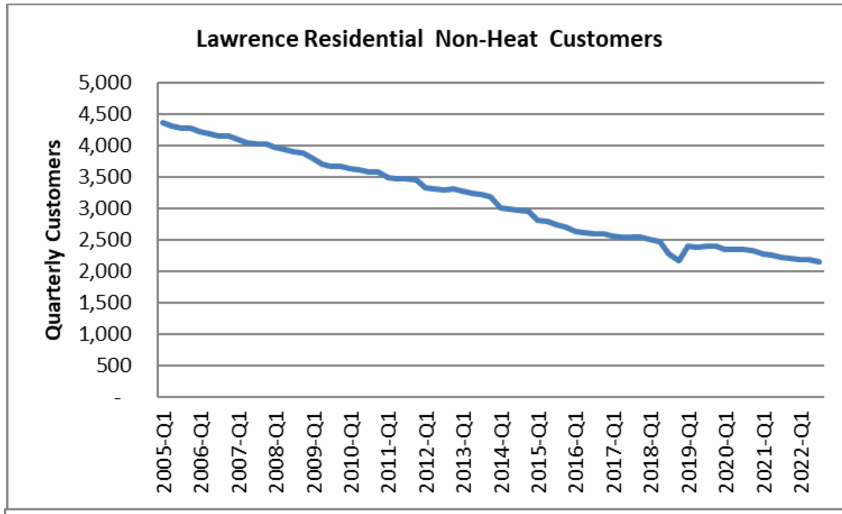

Springfield Residential Heat Rolling 4Q Average Use Per Customer
Dth per Customer
30.0
25.0
20.0
15.0
10.0
5.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

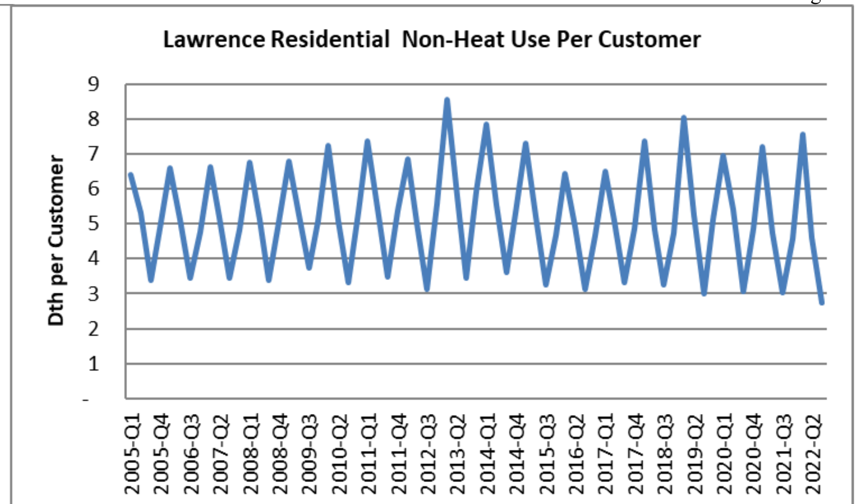

Brockton Residential Non-Heat Customers
Quarterly Customers
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

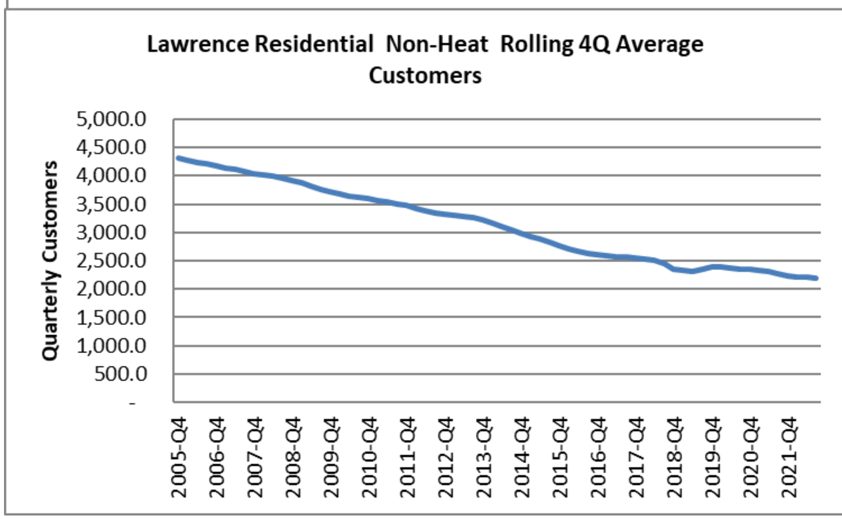

Brockton Residential Non-Heat Use Per Customer
Dth per Customer
8
7
6
5
4
3
2
1
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

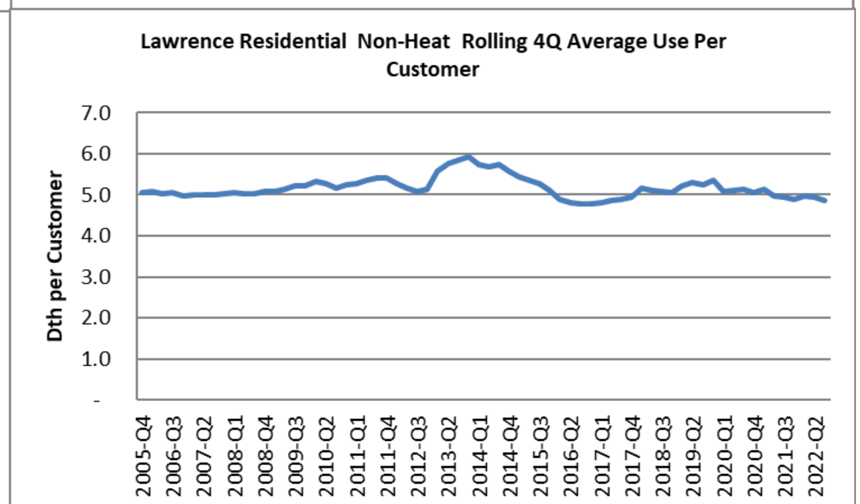

Brockton Residential Non-Heat Rolling 4Q Average Customers
Quarterly Customers
14,000.0
12,000.0
10,000.0
8,000.0
6,000.0
4,000.0
2,000.0
-
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4

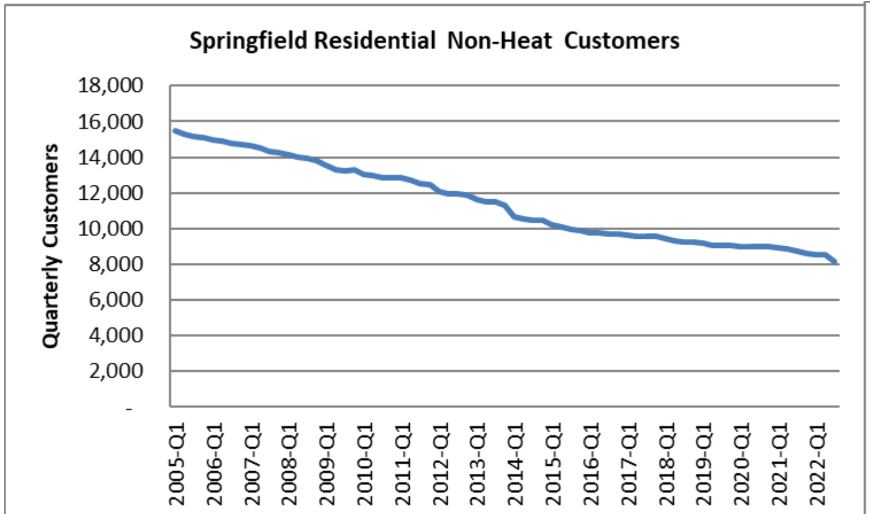

Brockton Residential Non-Heat Rolling 4Q Average Use Per Customer
Dth per Customer
6.0
5.0
4.0
3.0
2.0
1.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

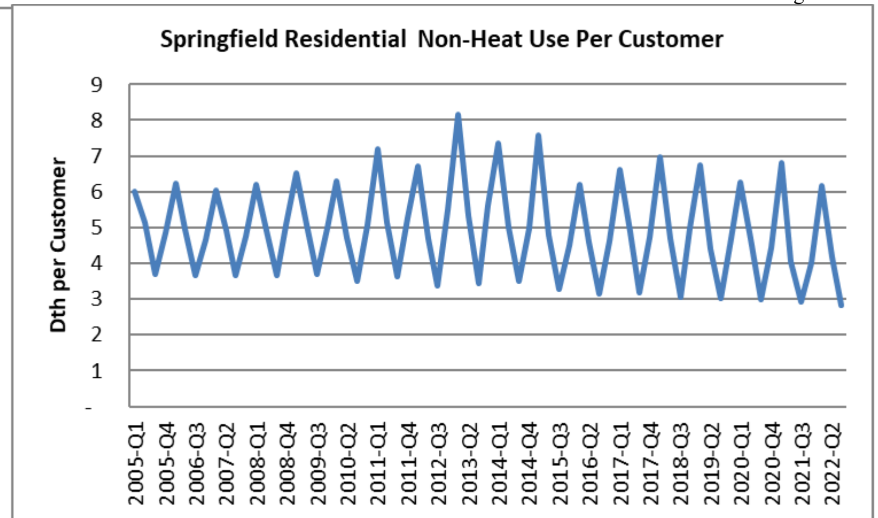

Lawrence Residential Non-Heat Customers
Quarterly Customers
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

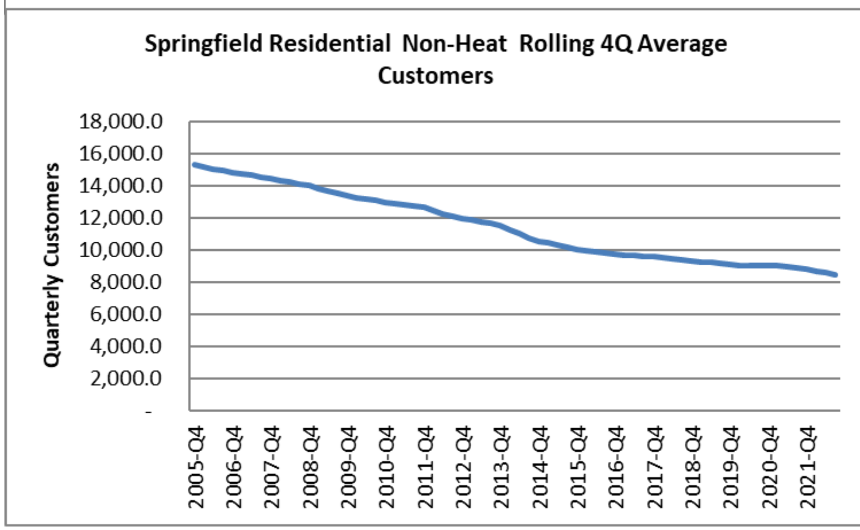

Lawrence Residential Non-Heat Use Per Customer
Dth per Customer
9
8
7
6
5
4
3
2
1
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

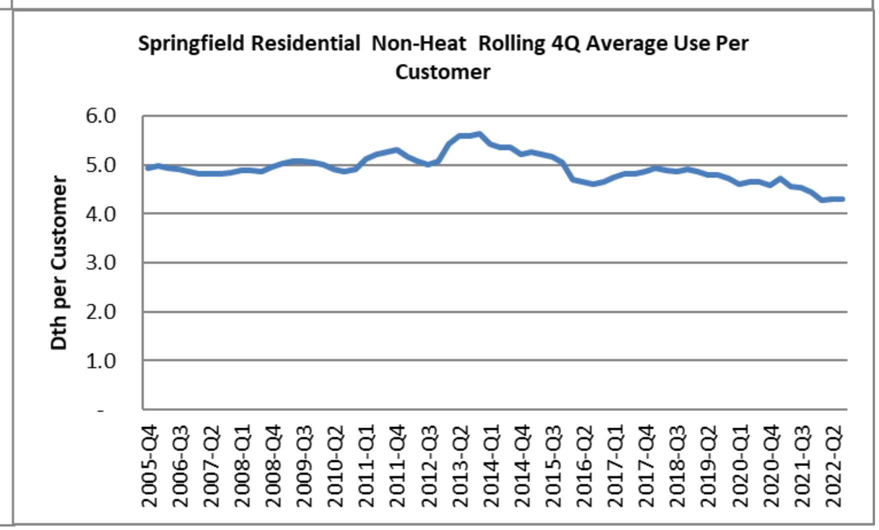

Lawrence Residential Non-Heat Rolling 4Q Average Customers
Quarterly Customers
5,000.0
4,500.0
4,000.0
3,500.0
3,000.0
2,500.0
2,000.0
1,500.0
1,000.0
500.0
-
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4

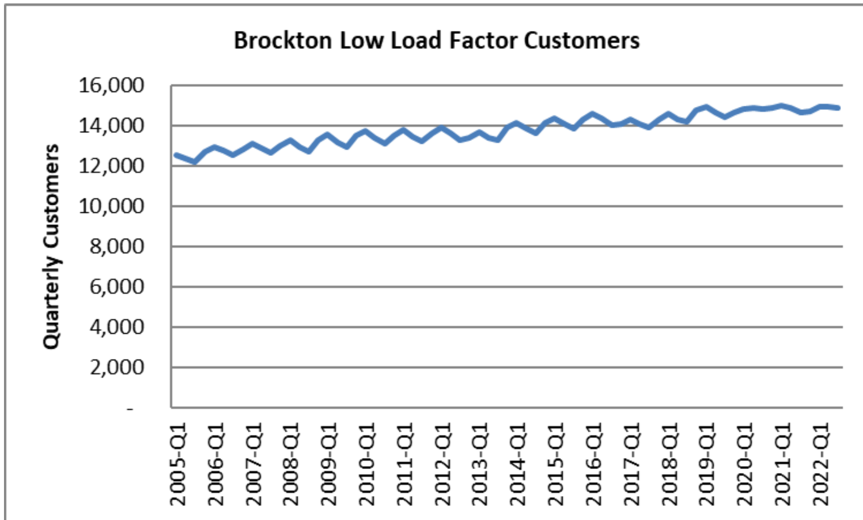

Lawrence Residential Non-Heat Rolling 4Q Average Use Per Customer
Dth per Customer
7.0
6.0
5.0
4.0
3.0
2.0
1.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

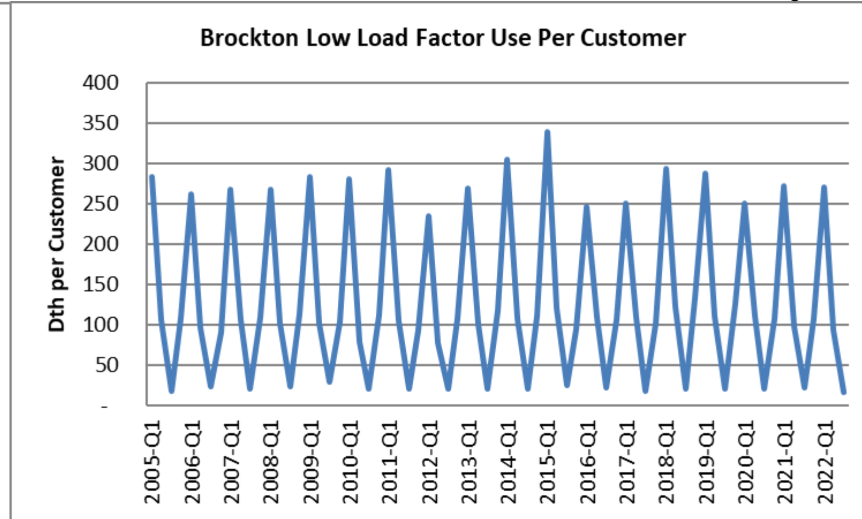

Springfield Residential Non-Heat Customers
Quarterly Customers
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

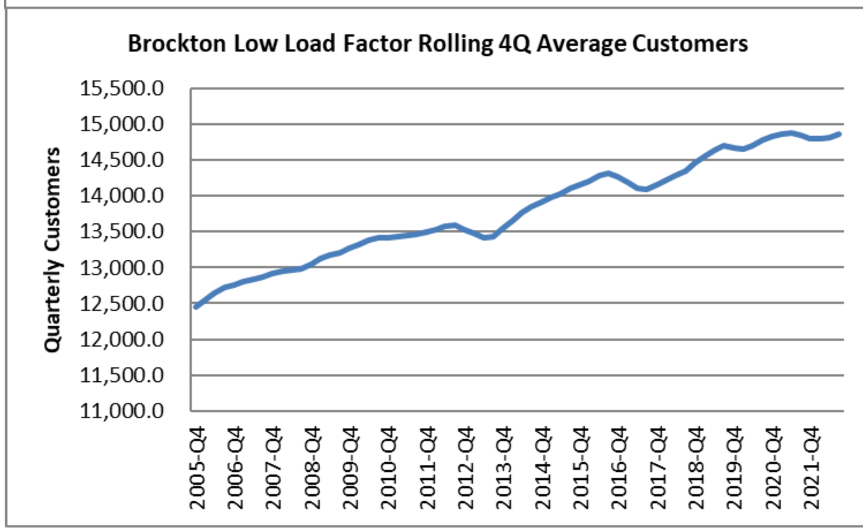

Springfield Residential Non-Heat Use Per Customer
Dth per Customer
9
8
7
6
5
4
3
2
1
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

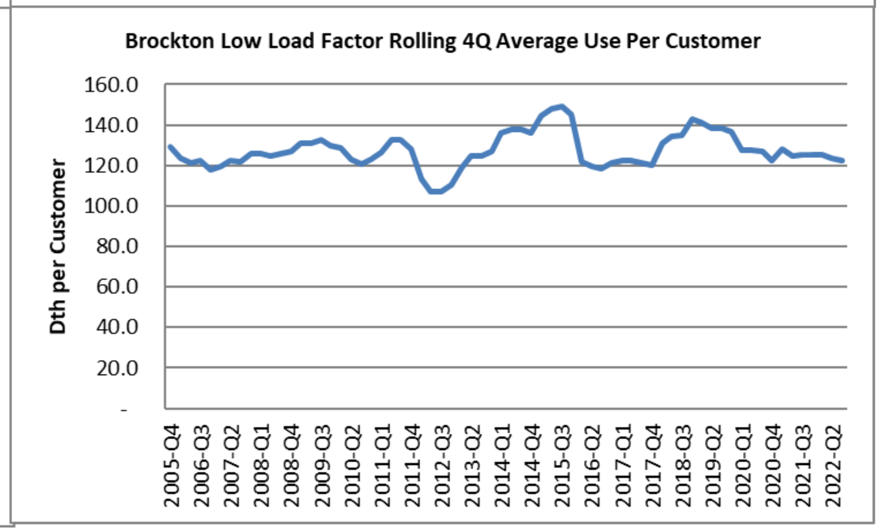

Springfield Residential Non-Heat Rolling 4Q Average Customers
Quarterly Customers
18,000.0
16,000.0
14,000.0
12,000.0
10,000.0
8,000.0
6,000.0
4,000.0
2,000.0
-
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4

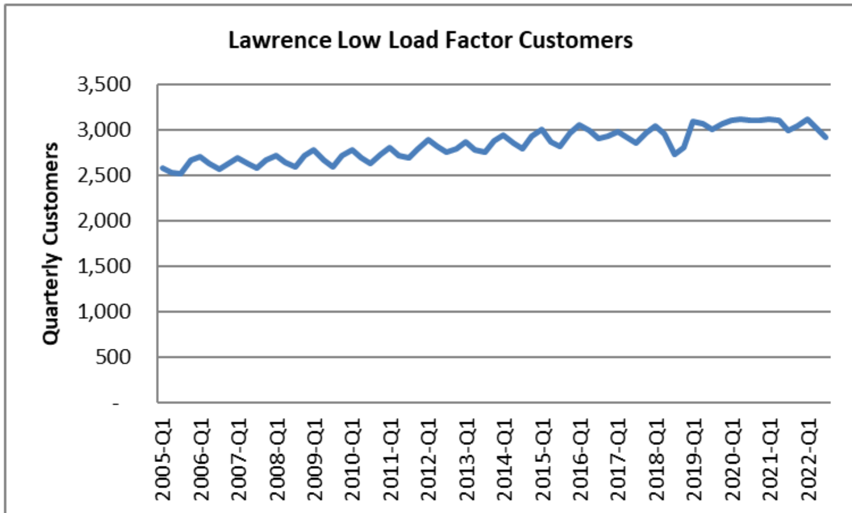

Springfield Residential Non-Heat Rolling 4Q Average Use Per Customer
Dth per Customer
6.0
5.0
4.0
3.0
2.0
1.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

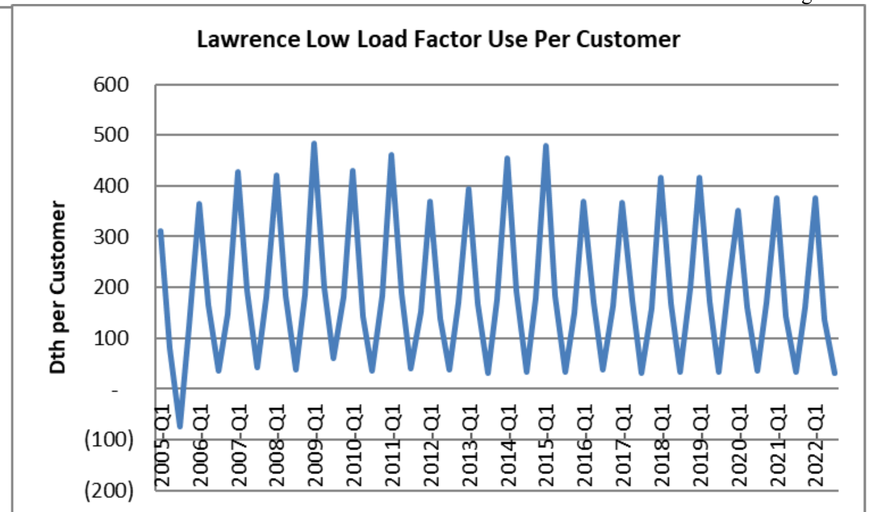

Brockton Low Load Factor Customers
Quarterly Customers
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

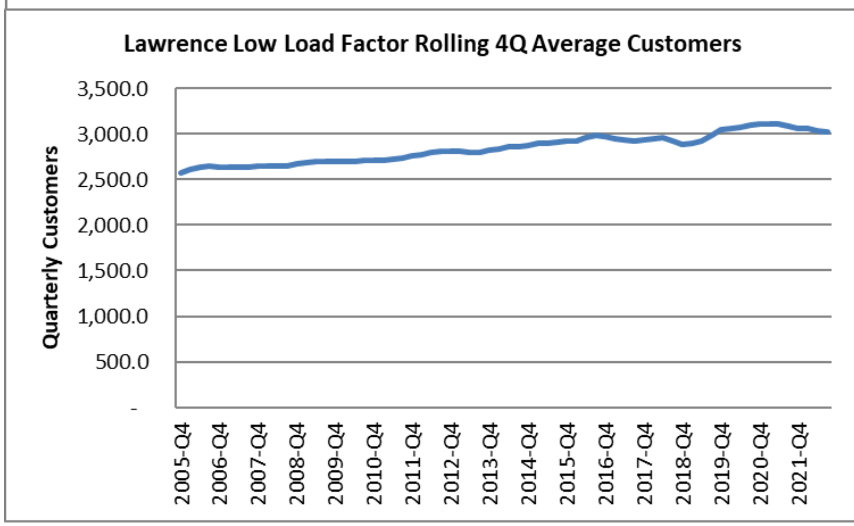

Brockton Low Load Factor Use Per Customer
Dth per Customer
400
350
300
250
200
150
100
50
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1


Brockton Low Load Factor Rolling 4Q Average Customers
Quarterly Customers
15,500.0
15,000.0
14,500.0
14,000.0
13,500.0
13,000.0
12,500.0
12,000.0
11,500.0
11,000.0
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4


Brockton Low Load Factor Rolling 4Q Average Use Per Customer
Dth per Customer
160.0
140.0
120.0
100.0
80.0
60.0
40.0
20.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2


Lawrence Low Load Factor Customers
Quarterly Customers
3,500
3,000
2,500
2,000
1,500
1,000
500
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1


Lawrence Low Load Factor Use Per Customer
Dth per Customer
600
500
400
300
200
100
-
(100)
(200)
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1


Lawrence Low Load Factor Rolling 4Q Average Customers
Quarterly Customers
3,500.0
3,000.0
2,500.0
2,000.0
1,500.0
1,000.0
500.0
-
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
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2014-Q4
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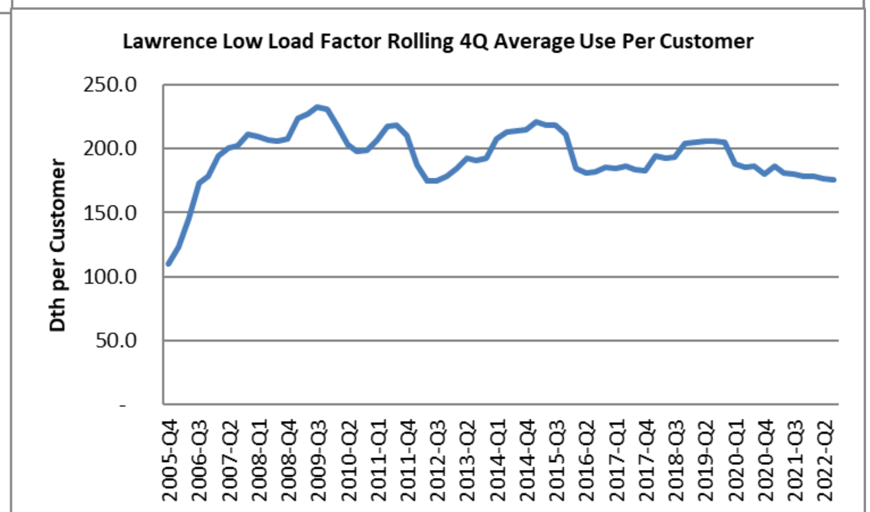
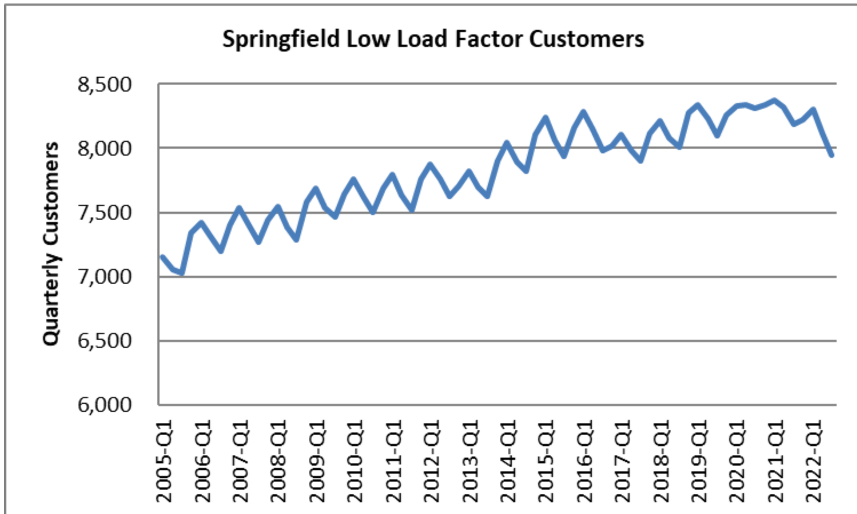
2018-Q4
2019-Q4
2020-Q4
2021-Q4


Lawrence Low Load Factor Rolling 4Q Average Use Per Customer
Dth per Customer
250.0
200.0
150.0
100.0
50.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2


Springfield Low Load Factor Customers
Quarterly Customers
8,500
8,000
7,500
7,000
6,500
6,000
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
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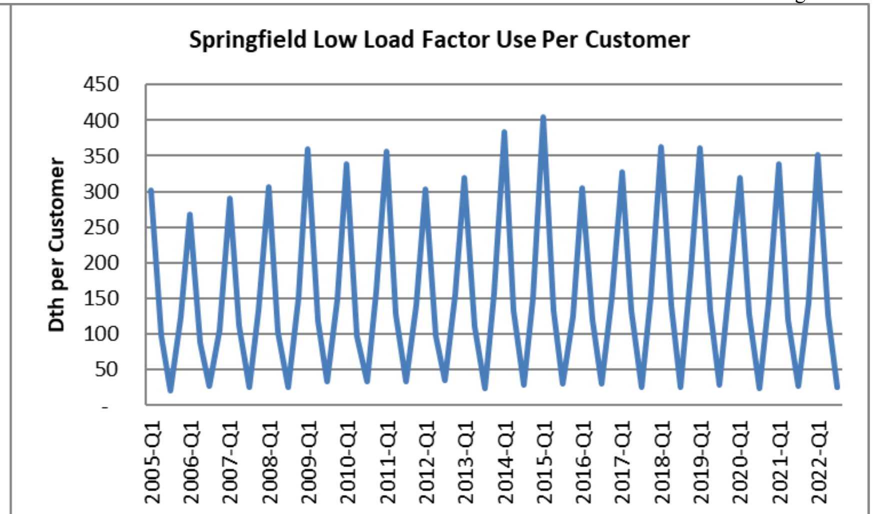
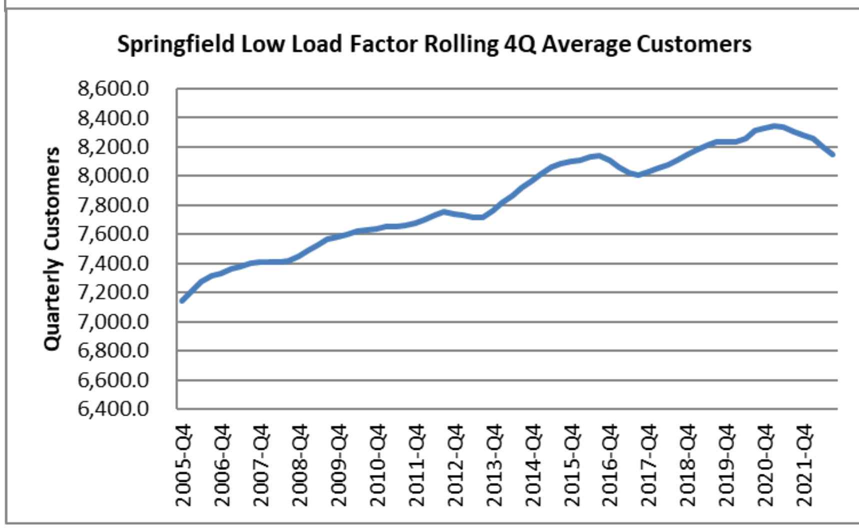
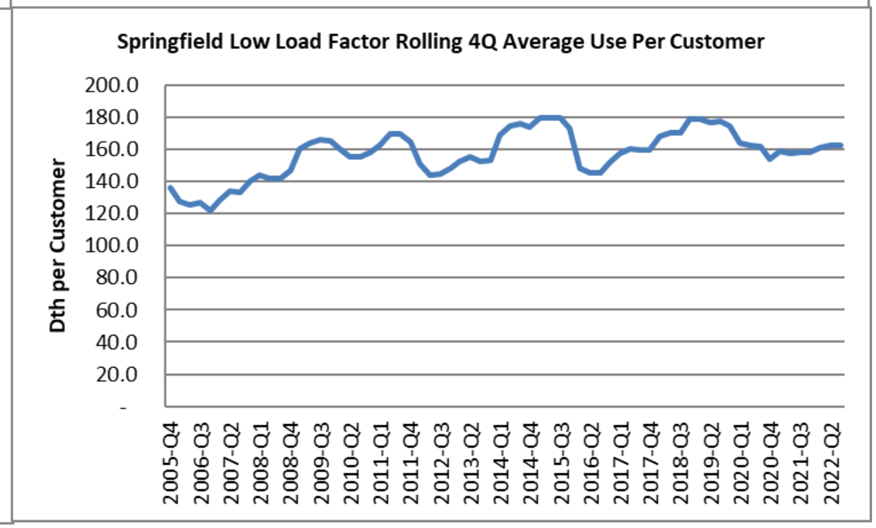
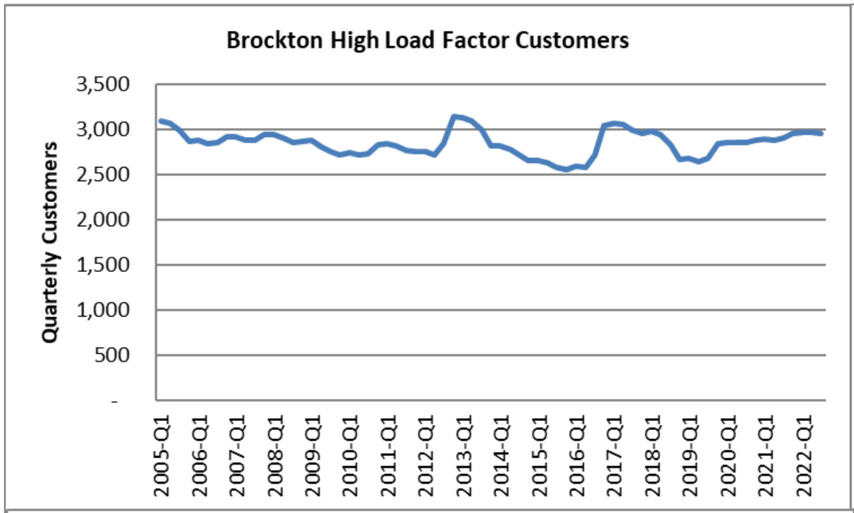
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1


Springfield Low Load Factor Use Per Customer
Dth per Customer
450
400
350
300
250
200
150
100
50
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1


Springfield Low Load Factor Rolling 4Q Average Customers
Quarterly Customers
8,600.0
8,400.0
8,200.0
8,000.0
7,800.0
7,600.0
7,400.0
7,200.0
7,000.0
6,800.0
6,600.0
6,400.0
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4


Springfield Low Load Factor Rolling 4Q Average Use Per Customer
Dth per Customer
200.0
180.0
160.0
140.0
120.0
100.0
80.0
60.0
40.0
20.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2


Brockton High Load Factor Customers
Quarterly Customers
3,500
3,000
2,500
2,000
1,500
1,000
500
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
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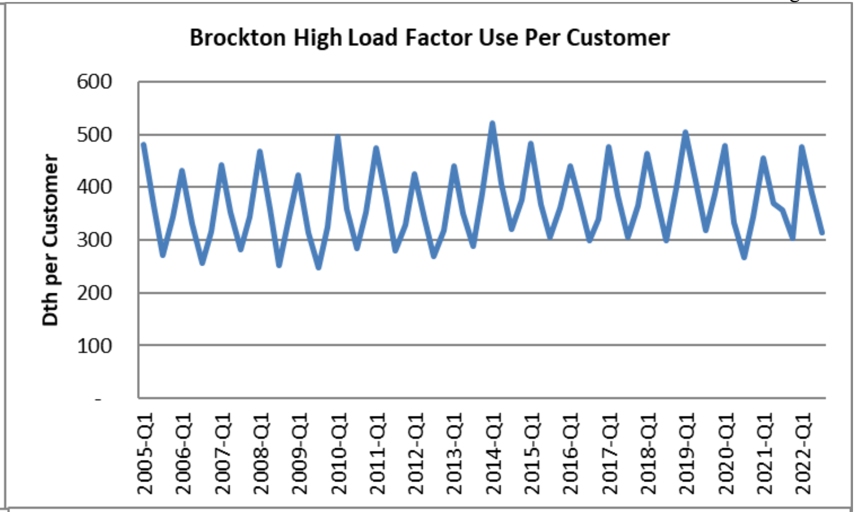
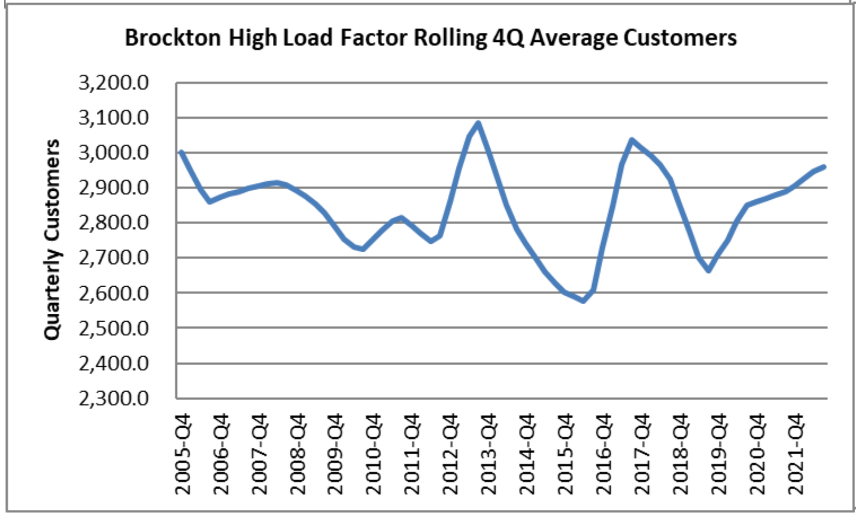
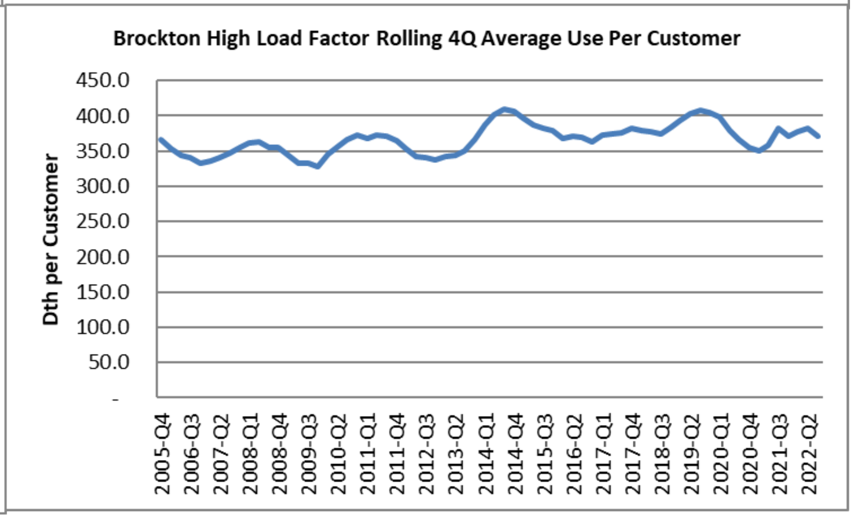
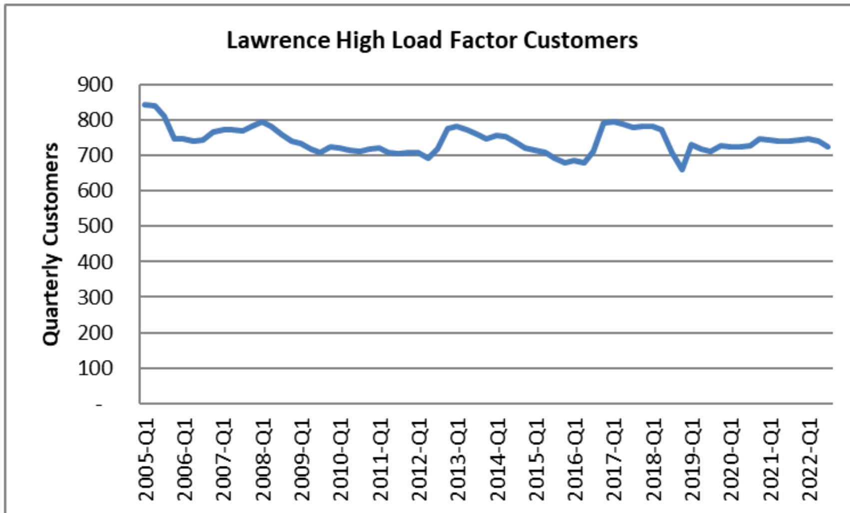
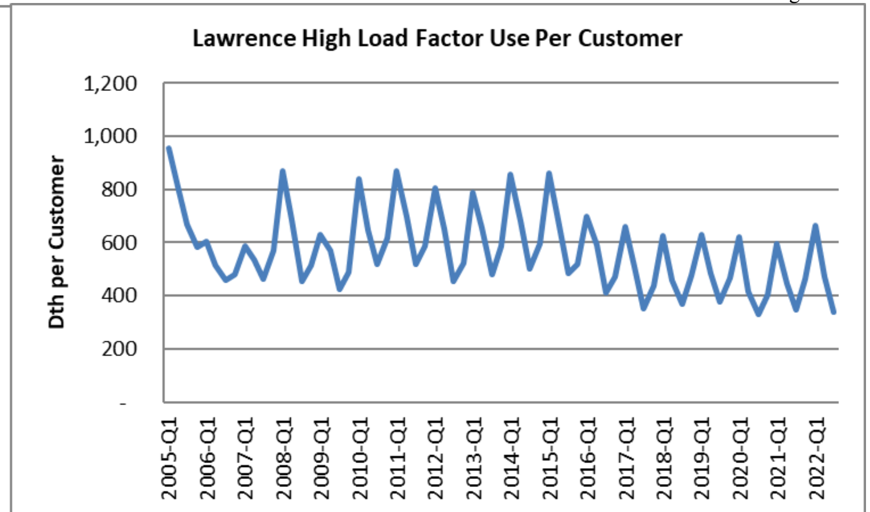
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

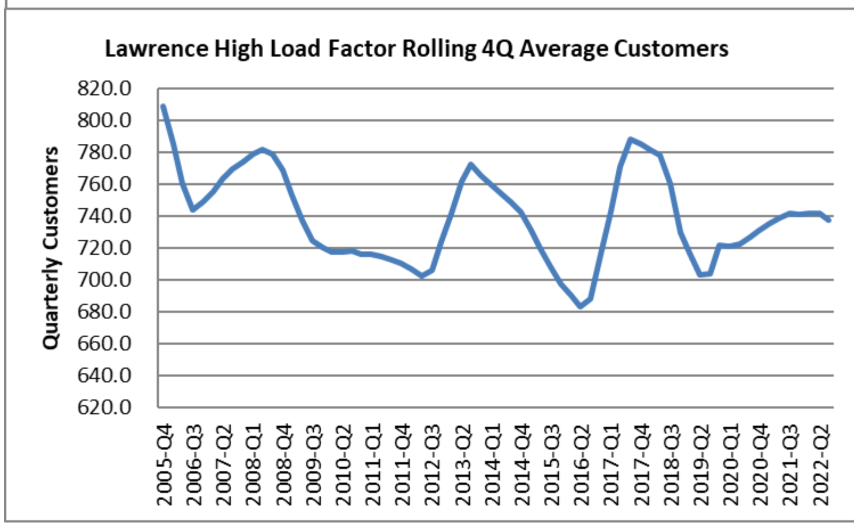

Brockton High Load Factor Use Per Customer
Dth per Customer
600
500
400
300
200
100
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

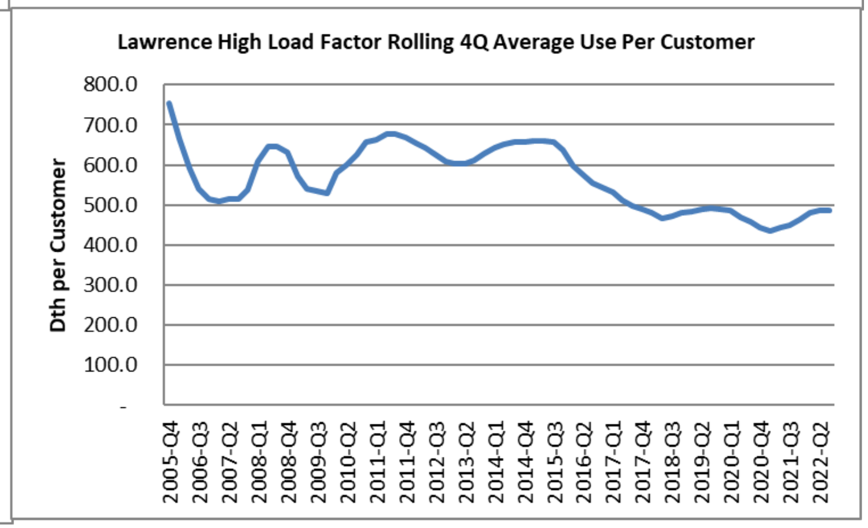

Brockton High Load Factor Rolling 4Q Average Customers
Quarterly Customers
3,200.0
3,100.0
3,000.0
2,900.0
2,800.0
2,700.0
2,600.0
2,500.0
2,400.0
2,300.0
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4

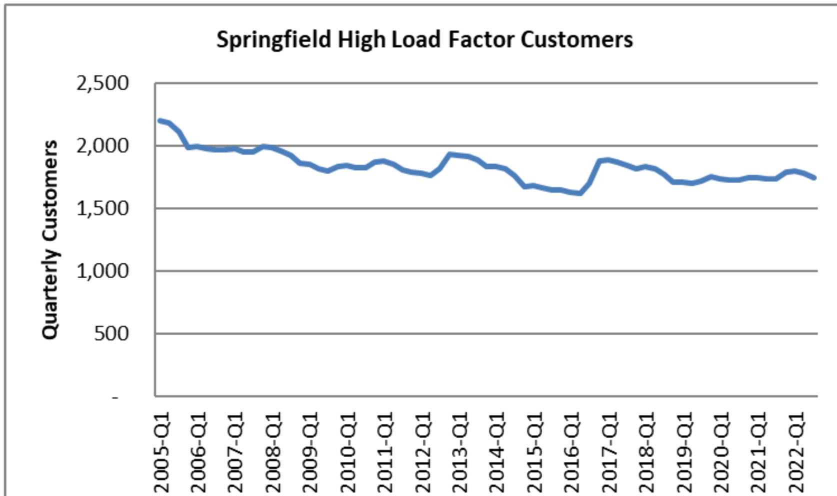

Brockton High Load Factor Rolling 4Q Average Use Per Customer
Dth per Customer
450.0
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

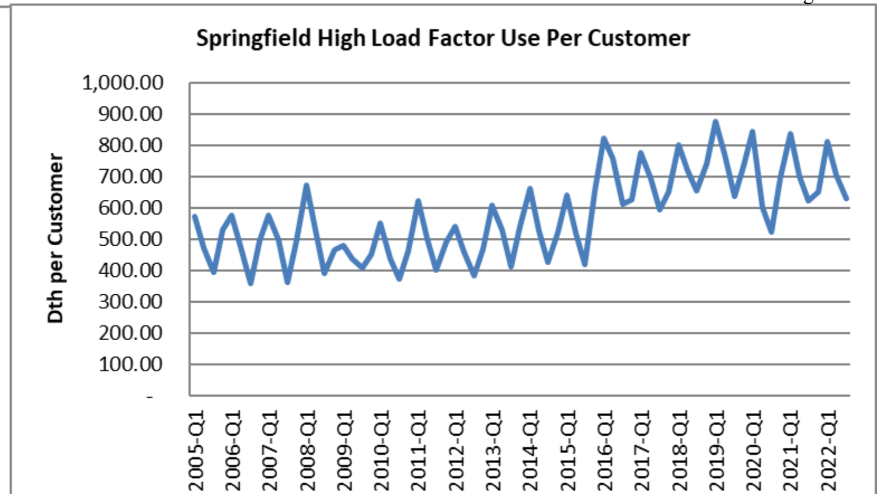

Lawrence High Load Factor Customers
Quarterly Customers
900
800
700
600
500
400
300
200
100
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

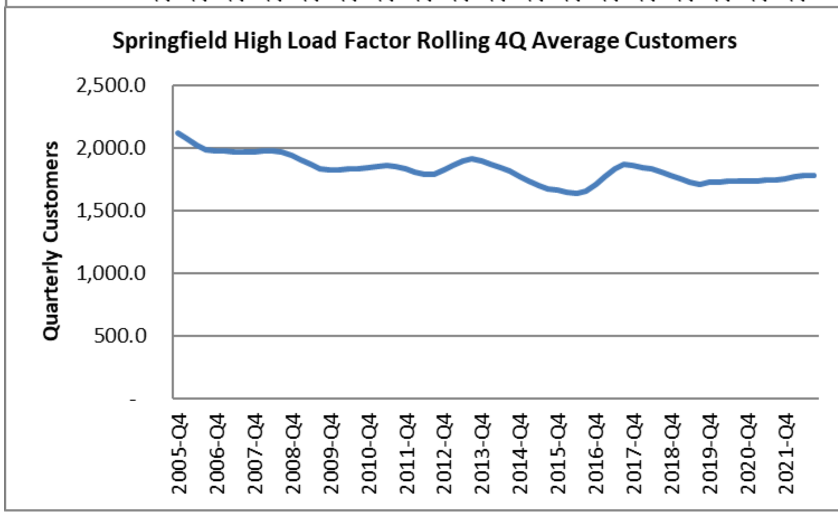

Lawrence High Load Factor Use Per Customer
Dth per Customer
1,200
1,000
800
600
400
200
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

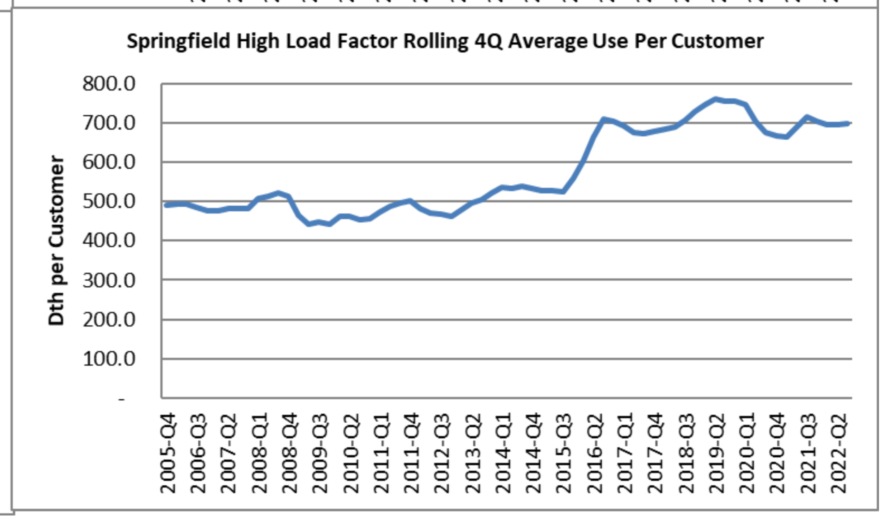

Lawrence High Load Factor Rolling 4Q Average Customers
Quarterly Customers
820.0
800.0
780.0
760.0
740.0
720.0
700.0
680.0
660.0
640.0
620.0
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2


Lawrence High Load Factor Rolling 4Q Average Use Per Customer
Dth per Customer
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

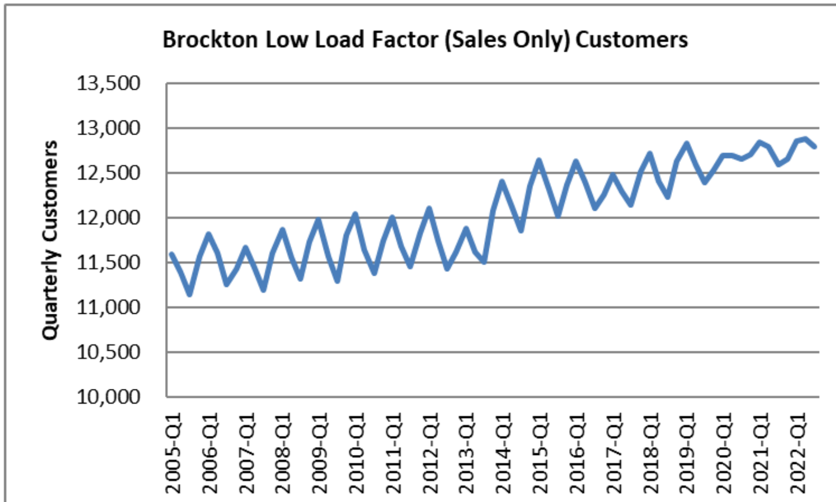

Springfield High Load Factor Customers
Quarterly Customers
2,500
2,000
1,500
1,000
500
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

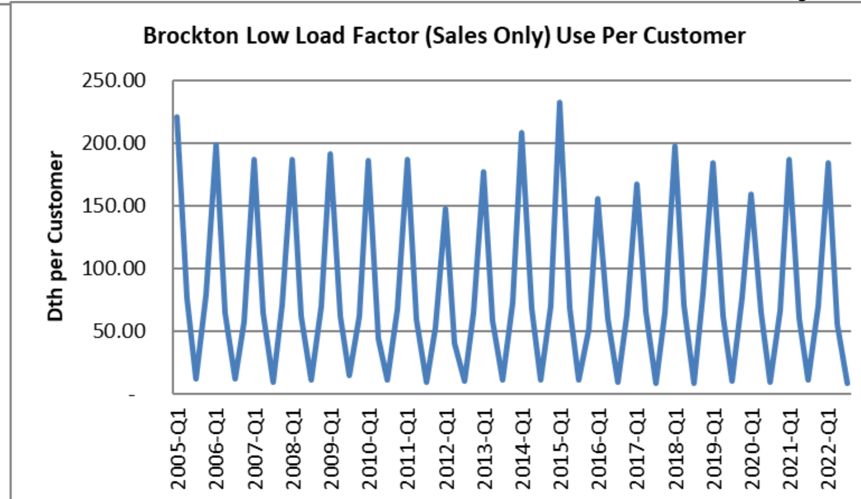

Springfield High Load Factor Use Per Customer
Dth per Customer
1,000.00
900.00
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

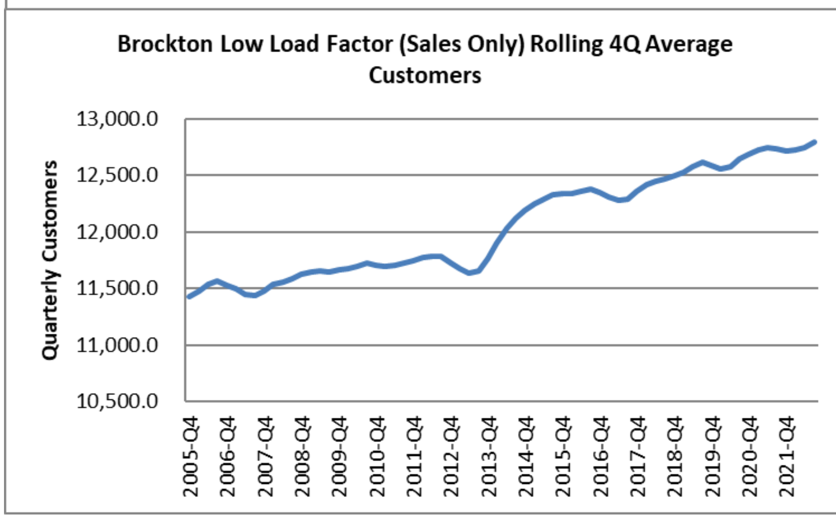

Springfield High Load Factor Rolling 4Q Average Customers
Quarterly Customers
2,500.0
2,000.0
1,500.0
1,000.0
500.0
-
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4

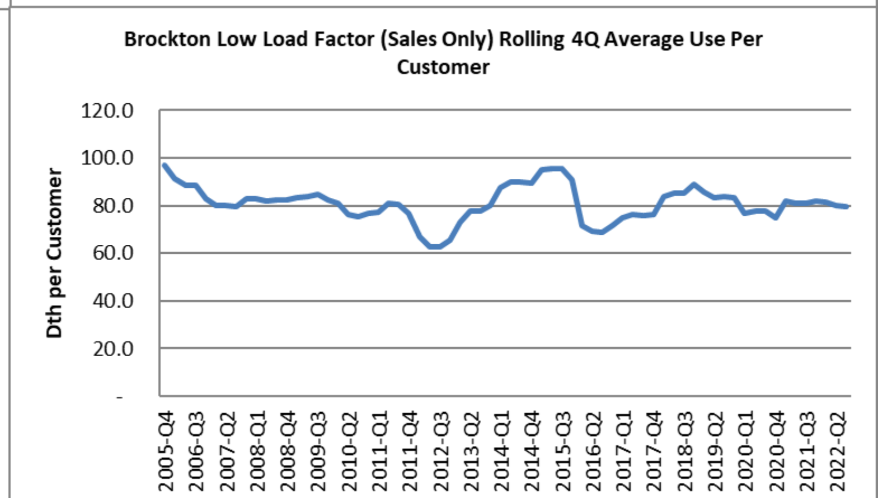

Springfield High Load Factor Rolling 4Q Average Use Per Customer
Dth per Customer
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

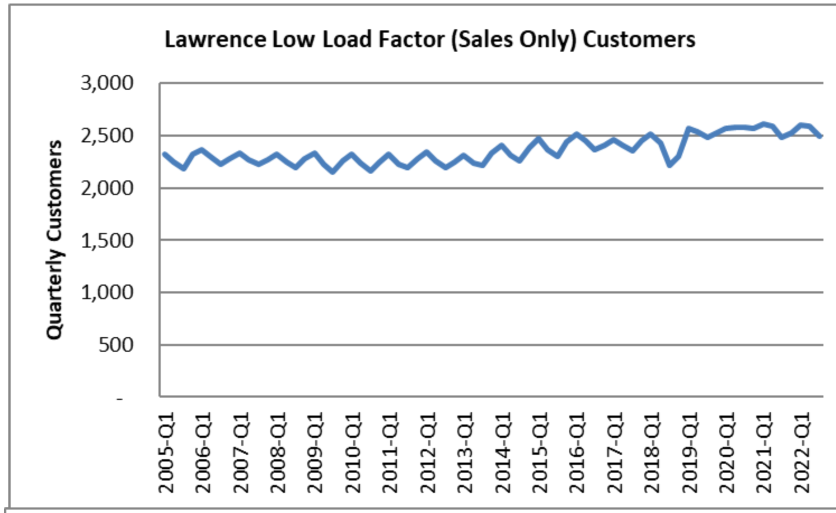
Sales Only:

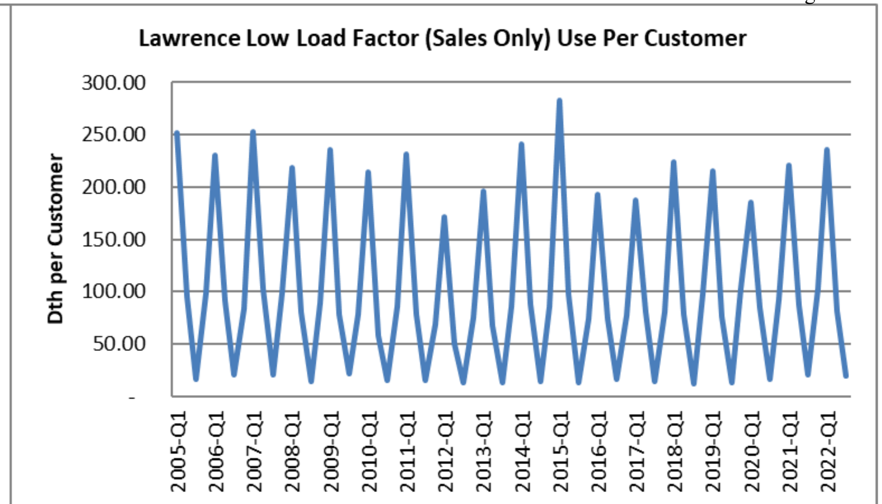

Brockton Low Load Factor (Sales Only) Customers
Quarterly Customers
13,500
13,000
12,500
12,000
11,500
11,000
10,500
10,000
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

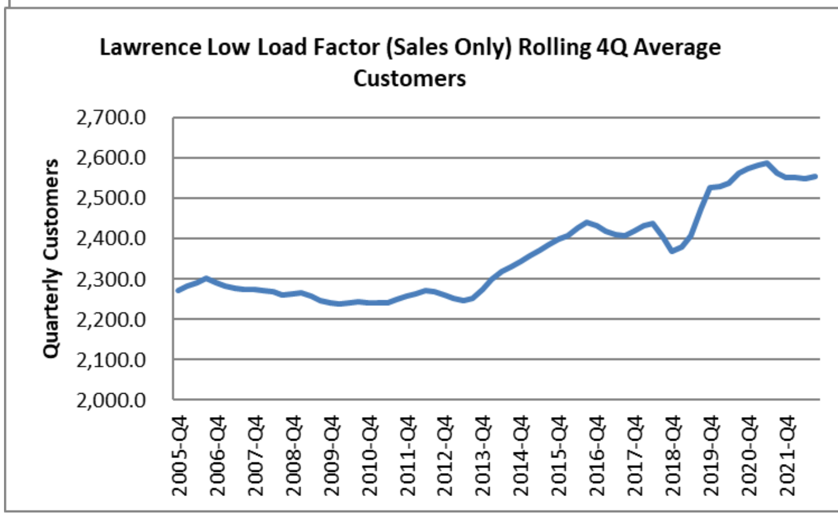

Brockton Low Load Factor (Sales Only) Use Per Customer
Dth per Customer
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

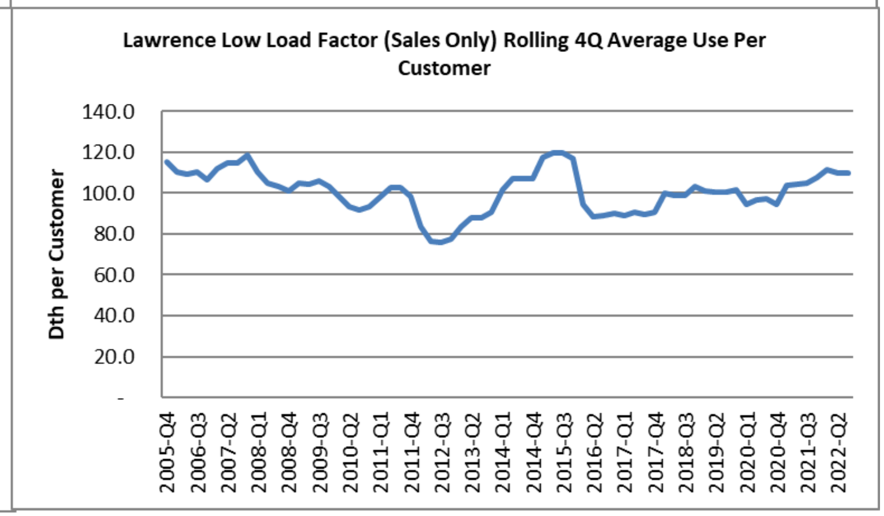

Brockton Low Load Factor (Sales Only) Rolling 4Q Average Customers
Quarterly Customers
13,000.0
12,500.0
12,000.0
11,500.0
11,000.0
10,500.0
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4

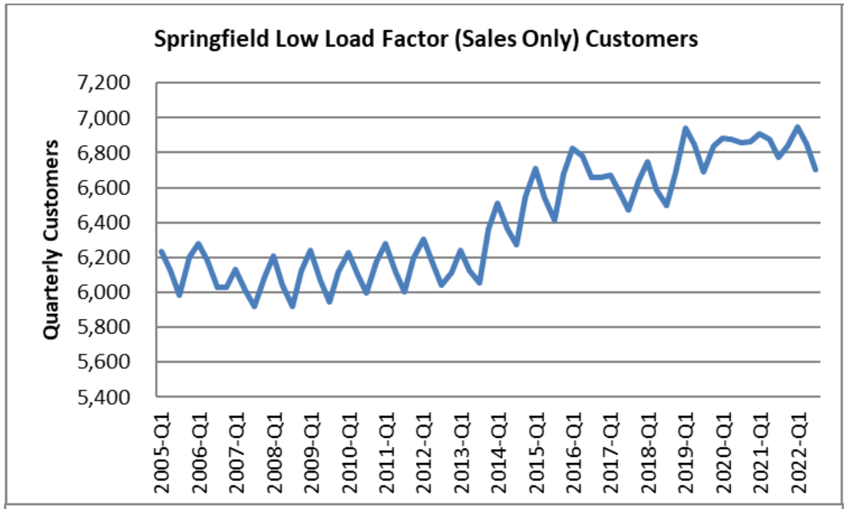

Brockton Low Load Factor (Sales Only) Rolling 4Q Average Use Per Customer
Dth per Customer
120.0
100.0
80.0
60.0
40.0
20.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

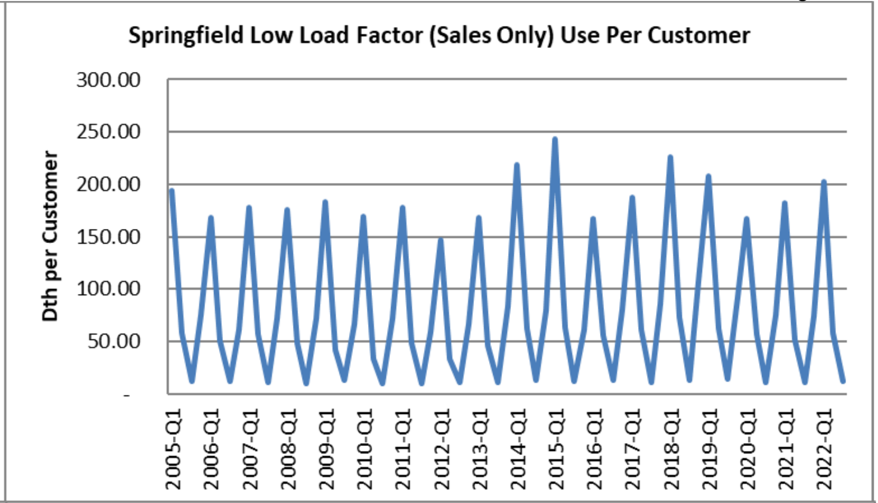

Lawrence Low Load Factor (Sales Only) Customers
Quarterly Customers
3,000
2,500
2,000
1,500
1,000
500
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

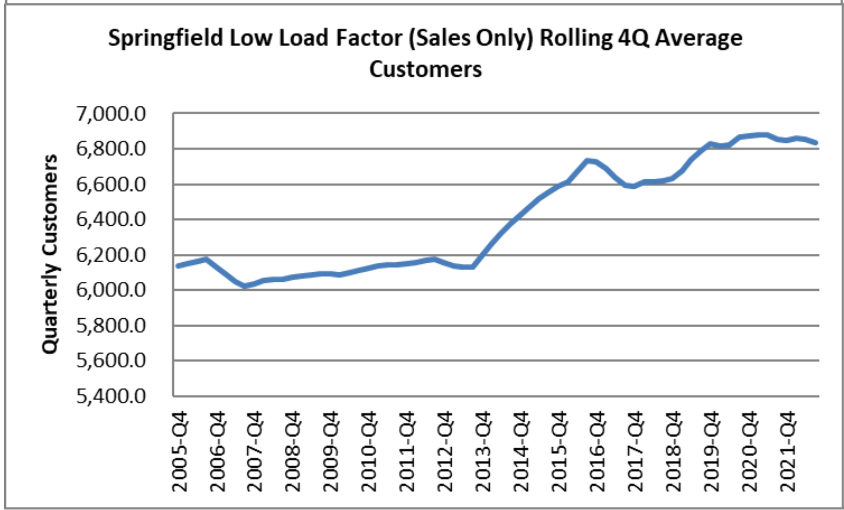

Lawrence Low Load Factor (Sales Only) Use Per Customer
Dth per Customer
300.00
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

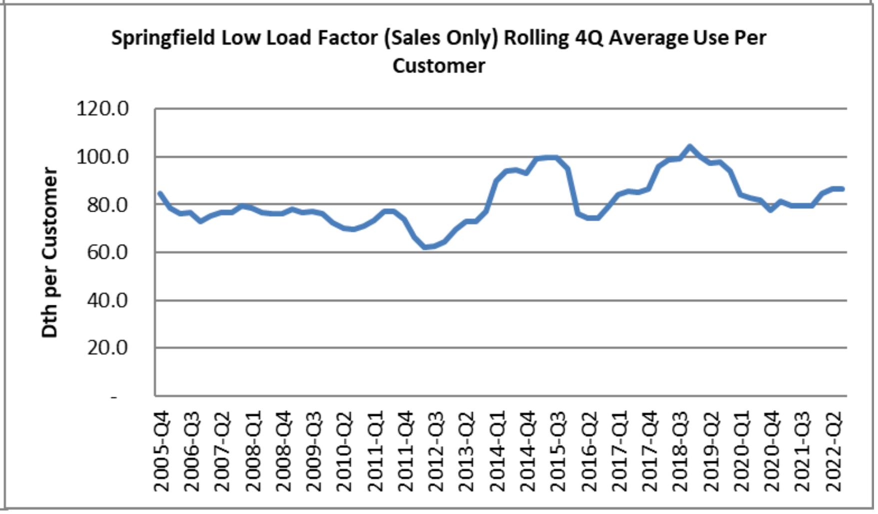

Lawrence Low Load Factor (Sales Only) Rolling 4Q Average Customers
Quarterly Customers
2,700.0
2,600.0
2,500.0
2,400.0
2,300.0
2,200.0
2,100.0
2,000.0
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4

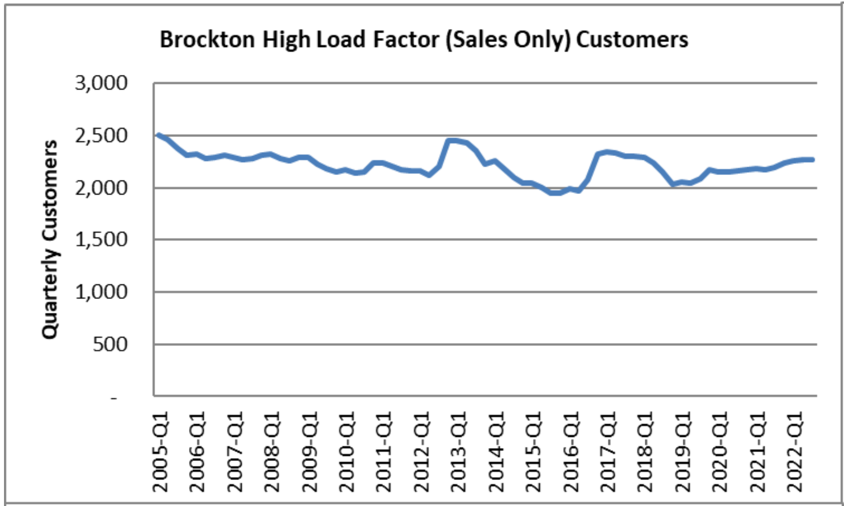

Lawrence Low Load Factor (Sales Only) Rolling 4Q Average Use Per Customer
Dth per Customer
140.0
120.0
100.0
80.0
60.0
40.0
20.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

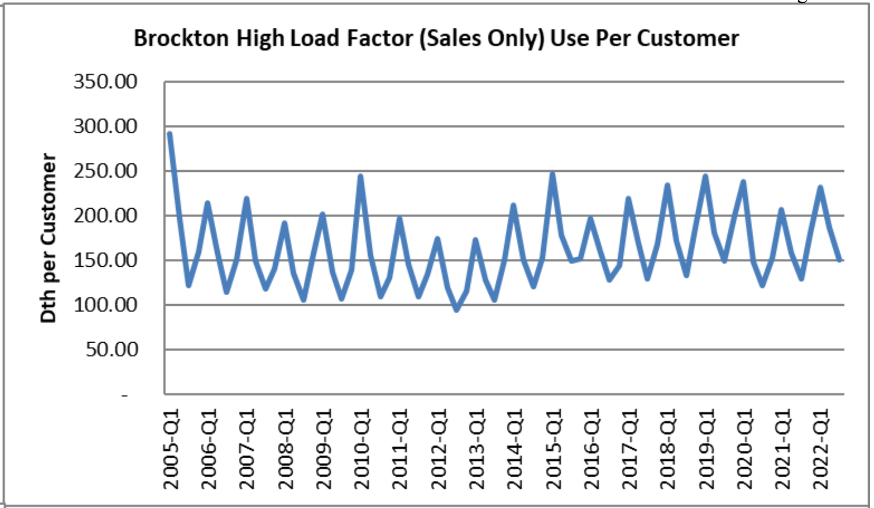

Springfield Low Load Factor (Sales Only) Customers
Quarterly Customers
7,200
7,000
6,800
6,600
6,400
6,200
6,000
5,800
5,600
5,400
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

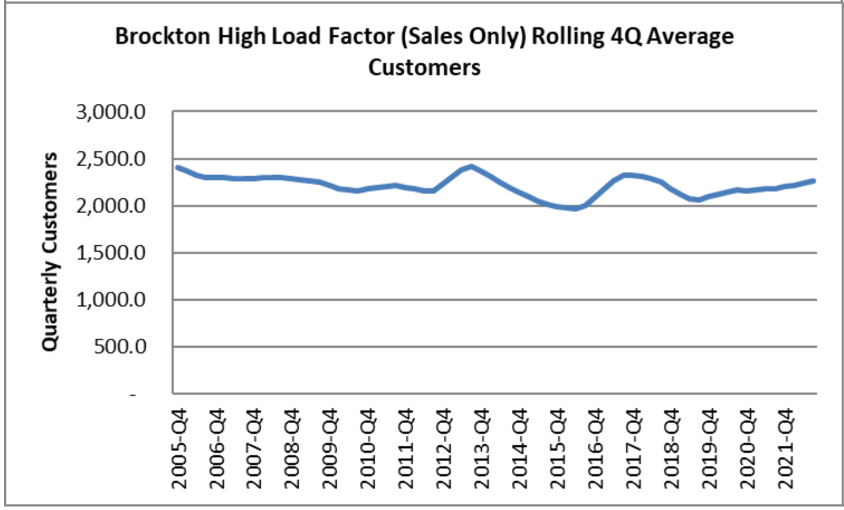

Springfield Low Load Factor (Sales Only) Use Per Customer
Dth per Customer
300.00
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

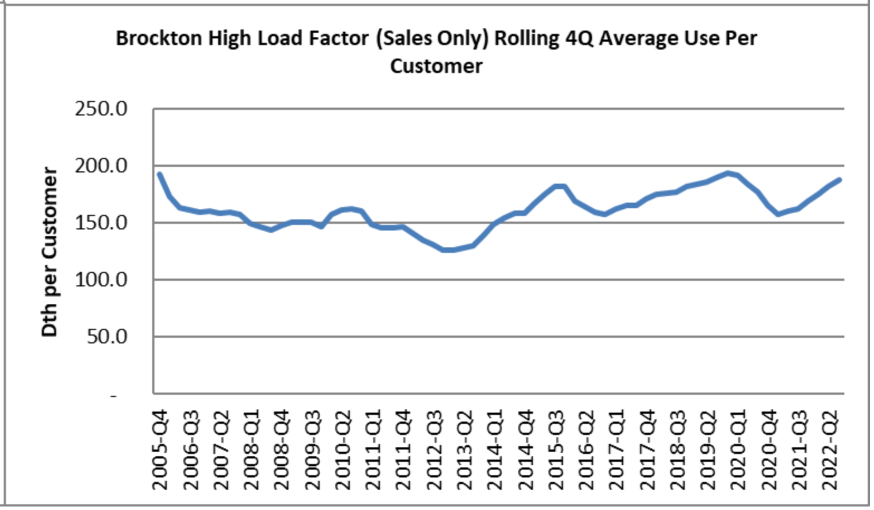

Springfield Low Load Factor (Sales Only) Rolling 4Q Average Customers
Quarterly Customers
7,000.0
6,800.0
6,600.0
6,400.0
6,200.0
6,000.0
5,800.0
5,600.0
5,400.0
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4

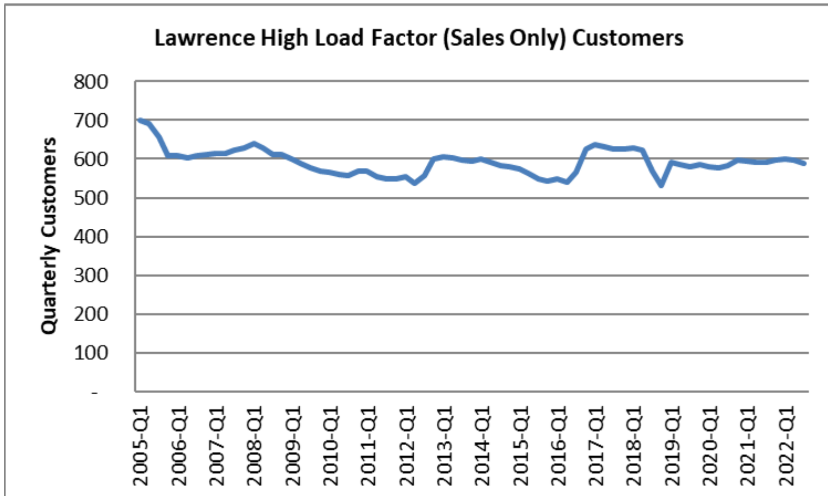

Springfield Low Load Factor (Sales Only) Rolling 4Q Average Use Per Customer
Dth per Customer
120.0
100.0
80.0
60.0
40.0
20.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

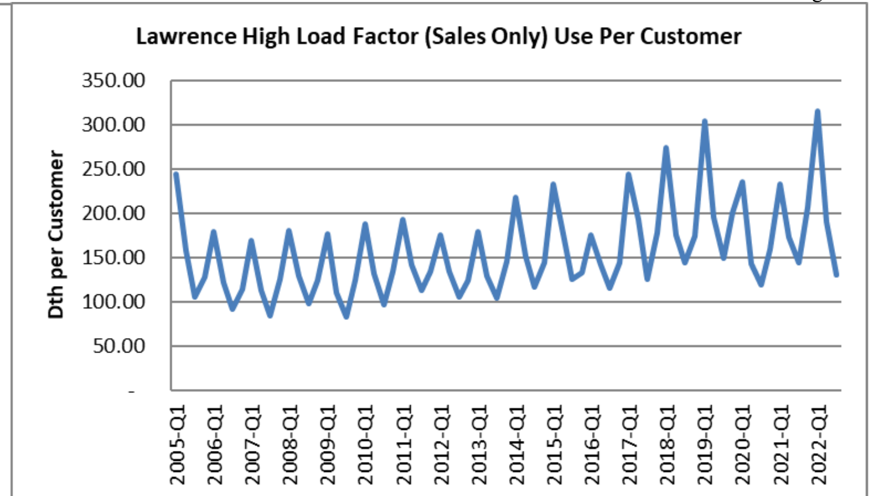

Brockton High Load Factor (Sales Only) Customers
Quarterly Customers
3,000
2,500
2,000
1,500
1,000
500
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

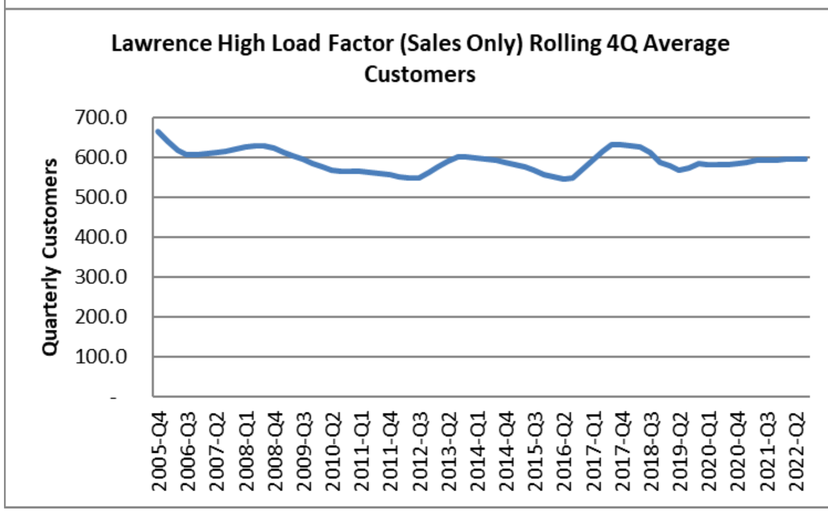

Brockton High Load Factor (Sales Only) Use Per Customer
Dth per Customer
350.00
300.00
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

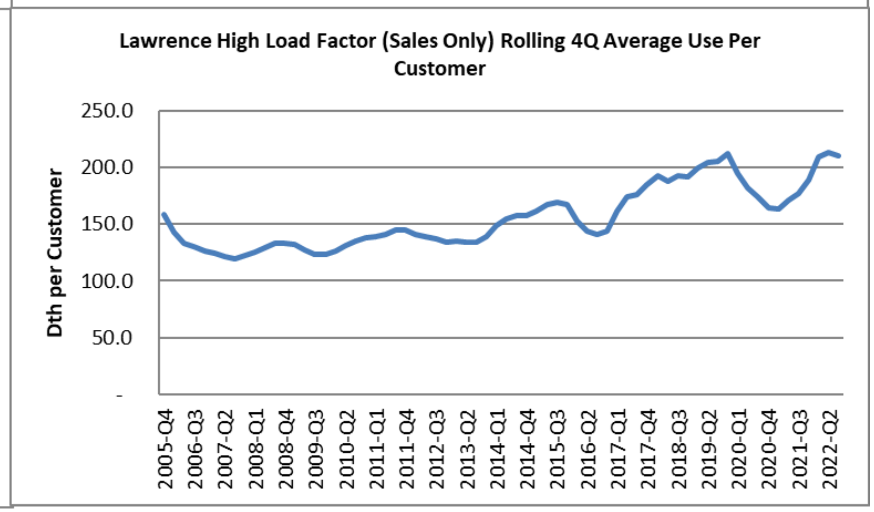

Brockton High Load Factor (Sales Only) Rolling 4Q Average Customers
Quarterly Customers
3,000.0
2,500.0
2,000.0
1,500.0
1,000.0
500.0
-
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4

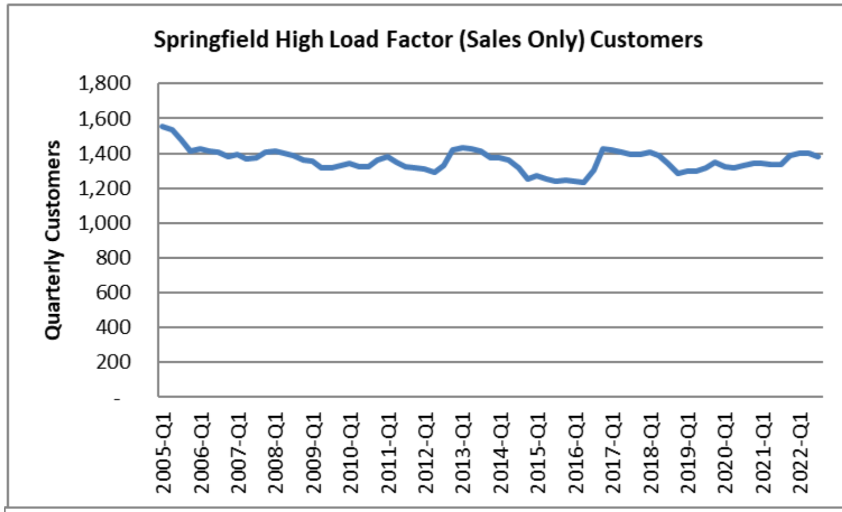

Brockton High Load Factor (Sales Only) Rolling 4Q Average Use Per Customer
Dth per Customer
250.0
200.0
150.0
100.0
50.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

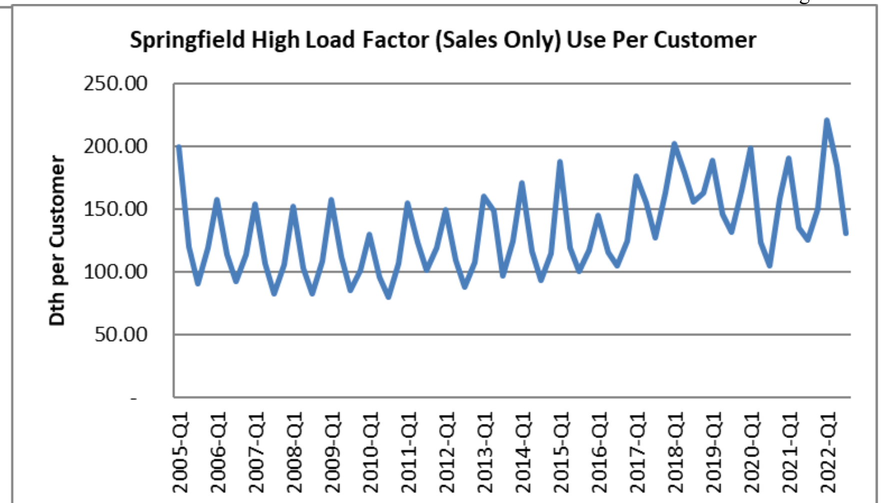

Lawrence High Load Factor (Sales Only) Customers
Quarterly Customers
800
700
600
500
400
300
200
100
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

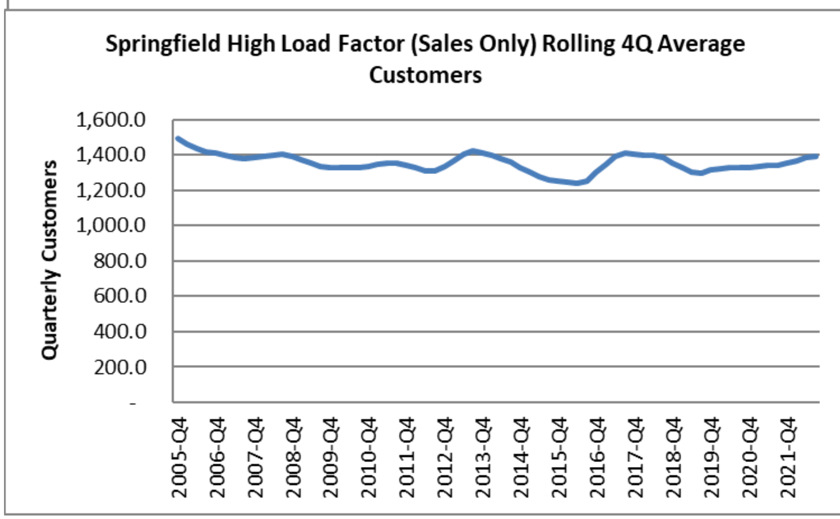

Lawrence High Load Factor (Sales Only) Use Per Customer
Dth per Customer
350.00
300.00
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1

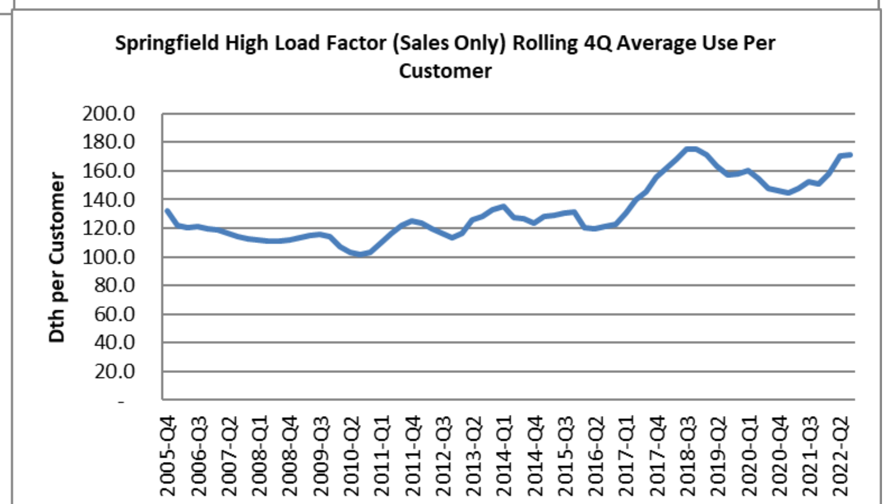

Lawrence High Load Factor (Sales Only) Rolling 4Q Average Customers
Quarterly Customers
700.0
600.0
500.0
400.0
300.0
200.0
100.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

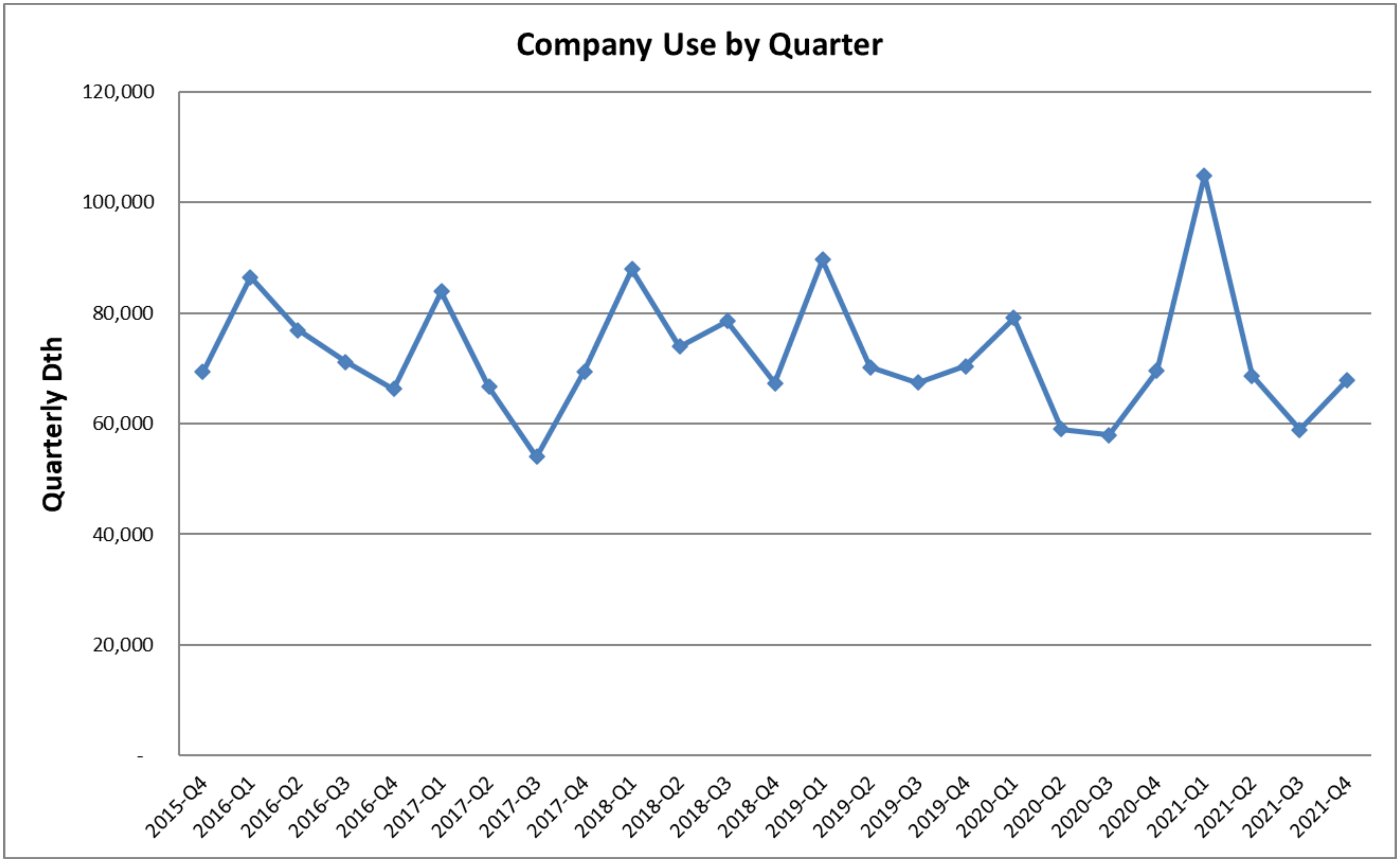

Lawrence High Load Factor (Sales Only) Rolling 4Q Average Use Per Customer
Dth per Customer
250.0
200.0
150.0
100.0
50.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2

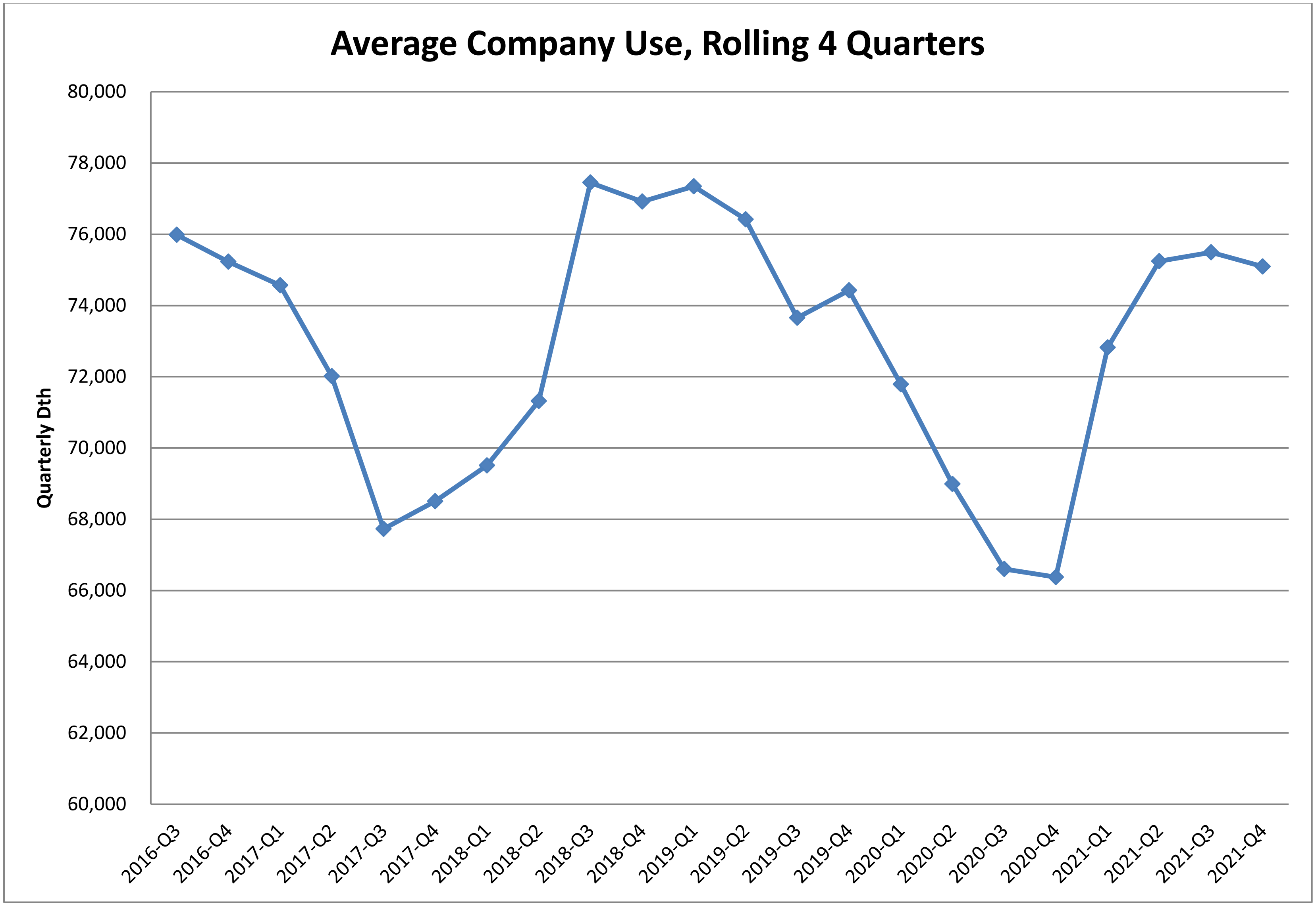

Springfield High Load Factor (Sales Only) Customers
Quarterly Customers
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1


Springfield High Load Factor (Sales Only) Use Per Customer
Dth per Customer
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2006-Q1
2007-Q1
2008-Q1
2009-Q1
2010-Q1
2011-Q1
2012-Q1
2013-Q1
2014-Q1
2015-Q1
2016-Q1
2017-Q1
2018-Q1
2019-Q1
2020-Q1
2021-Q1
2022-Q1


Springfield High Load Factor (Sales Only) Rolling 4Q Average Customers
Quarterly Customers
1,600.0
1,400.0
1,200.0
1,000.0
800.0
600.0
400.0
200.0
-
2005-Q4
2006-Q4
2007-Q4
2008-Q4
2009-Q4
2010-Q4
2011-Q4
2012-Q4
2013-Q4
2014-Q4
2015-Q4
2016-Q4
2017-Q4
2018-Q4
2019-Q4
2020-Q4
2021-Q4


Springfield High Load Factor (Sales Only) Rolling 4Q Average Use Per Customer
Dth per Customer
200.0
180.0
160.0
140.0
120.0
100.0
80.0
60.0
40.0
20.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1
2020-Q4
2021-Q3
2022-Q2


Company Use by Quarter
Quarterly Dth
120,000
100,000
80,000
60,000
40,000
20,000
-
2015-Q4
2016-Q1
2016-Q2
2016-Q3
2016-Q4
2017-Q1
2017-Q2
2017-Q3
2017-Q4
2018-Q1
2018-Q2
2018-Q3
2018-Q4
2019-Q1
2019-Q2
2019-Q3
2019-Q4
2020-Q1
2020-Q2
2020-Q3
2020-Q4
2021-Q1
2021-Q2
2021-Q3
2021-Q4


Average Company Use, Rolling 4 Quarters
Quarterly Dth
80,000
78,000
76,000
74,000
72,000
70,000
68,000
66,000
64,000
62,000
60,000
2016-Q3
2016-Q4
2017-Q1
2017-Q2
2017-Q3
2017-Q4
2018-Q1
2018-Q2
2018-Q3
2018-Q4
2019-Q1
2019-Q2
2019-Q3
2019-Q4
2020-Q1
2020-Q2
2020-Q3
2020-Q4
2021-Q1
2021-Q2
2021-Q3
2021-Q4

Appendix 10: Unbilled Calculation

To account for unbilled volumes, the Company used net unbilled history back to 2016. For each month from January 2016 through December 2022, the Company calculated historical average net unbilled. The monthly historical averages are shown in the table below. Those monthly historical averages became the forecast for net unbilled that the Company used in the forecast.

	Average Historical Net Unbilled
January	422,426
February	(745,989)
March	(408,415)
April	(1,237,284)
May	(1,169,429)
June	(607,250)
July	949
August	92,899
September	145,629
October	689,859
November	1,393,967
December	1,340,514

Calculation of Residential Energy Efficiency Forecast (Dth)

	Residential (including Low Income)			
	Incremental History	Incremental Forecast	Forecasted Incremental Less Trend	Forecasted Cumulative Less Trend (Impacts Forecast)
2010	87,135			
2011	93,898			
2012	125,406			
2013	174,692			
2014	200,542			
2015	245,794			
2016	255,246			
2017	233,048			
2018	282,899			
2019	292,734			
2020	264,093			
2021	291,798			
2022		258,316	21,690	21,690
2023		270,783	34,158	55,848
2024		287,316	50,691	106,539
2025		287,316	50,691	157,230
2026		287,316	50,691	207,921
2027		287,316	50,691	258,612
2028		287,316	50,691	309,303
2029		287,316	50,691	359,994
2030		287,316	50,691	410,685
2031		287,316	50,691	461,376
2032		287,316	50,691	512,067
('12 to '21) Historical Trend	236,625			

The same calculations were performed for C&I customers, and are demonstrated below.

Calculation of C&I Energy Efficiency Forecast (Dth)

	Commercial & Industrial			
	Incremental History	Incremental Forecast	Forecasted Incremental Less Trend	Forecasted Cumulative Less Trend (Impacts Forecast)
2010	162,964			
2011	132,556			
2012	149,369			
2013	196,014			
2014	208,141			
2015	120,748			
2016	125,893			
2017	91,354			
2018	188,863			
2019	124,101			
2020	125,877			
2021	262,912			
2022		124,003	-	-
2023		124,030	-	-
2024		124,215	-	-
2025		124,215	-	-
2026		124,215	-	-
2027		124,215	-	-
2028		124,215	-	-
2029		124,215	-	-
2030		124,215	-	-
2031		124,215	-	-
2032		124,215	-	-
('10 to '21) Historical Trend	157,399			

NOV 2023 thru OCT 2024 Cost and Flow Summary Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	136003	Injection Cost	188	Transportation Cost	3658	JAN 15, 2024	
Penalty Cost	0	Withdrawal Cost	225	Other Variable Cost	121	System Served	417.879
Other Variable Cost	0	Carrying Cost	0			System Unserved	0.000
		Other Variable Cost	0			Total	417.879
Total Variable	136003	Total Variable	413	Total Variable	3780		
Demand/Reservation Co	1.912e7	Demand Cost	3193	Demand Cost	118847		
Other Fixed Cost	0	Other Fixed Cost	4758	Other Fixed Cost	0		
Total Fixed	1.912e7	Total Fixed	7951	Total Fixed	118847		
Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0		
Net Supply Cost	1.926e7	Net Storage Cost	8364	Net Trans Cost	122627	Total Gas Cost	19394825
						Total Revenue	0
						Net Cost	19394825

Avg Cost of Served Demand 413.6 USD/DT Avg Cost of Gas Purchased 403.2 USD/DT
(System Cost/Served Dem.) (Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	46881.750	0.000	46881.750	0.000	46881.750	46881.750	0.000	0	417.879	0.000
Total	46881.750	0.000	46881.750	0.000	46881.750	46881.750	0.000	0	417.879	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	131.953	365634.000	365502.047			14.8621	1961	0	1961	14.8621
Centerville	2131.816	365634.000	363502.184			4.8379	10314	0	10314	4.8379
Dawn	11590.677	365634.000	354043.323			3.1955	37038	0	37038	3.1955
Dracut	78.059	365634.000	365555.941			8.2022	640	0	640	8.2022
TGP Z4 313	6340.589	365634.000	359293.411			2.2497	14265	0	14265	2.2497
TGP Z4 200	2849.303	365634.000	362784.697			2.7458	7824	0	7824	2.7458
Hereford	0.000	365634.000	365634.000			0.0000	0	0	0	0.0000
LNG Inject	649.143	365634.000	364984.857			5.1849	3366	0	3366	5.1849
LPG Inject	0.000	365634.000	365634.000			0.0000	0	0	0	0.0000

NOV 2023 thru OCT 2024 Cost and Flow Summary Units: MDT, USD (000)

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Millennium	3173.641	365634.000	362460.359			2.6169	8305	0	8305	2.6169
Niagara	3050.183	365634.000	362583.817			2.7184	8292	0	8292	2.7184
Ramapo	3448.418	365634.000	362185.582			2.5398	8758	0	8758	2.5398
Repsol 30	987.000	987.000	0.000			2.3530	2322	13029226	13031548	13203.1899
Repsol 40	564.000	564.000	0.000			2.3530	1327	6098606	6099933	10815.4842
TETCO M2	10136.006	365634.000	355497.994			2.4039	24366	0	24366	2.4039
TETCO M3	2636.512	365634.000	362997.488			2.7409	7226	0	7226	2.7409
Winter AGT	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Winter TGP	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Total	47767.300						136003	19127832	19263835	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	731.704	100	195.712	195.712	0.000	0.000	731.704	100	0.000	0.000	4527	4351	-176
LNG Lawrence	11.628	100	26.604	26.604	0.000	0.000	11.628	100	0.000	0.000	72	62	-10
LNG Marshfld	7.622	100	14.529	14.529	0.000	0.000	7.622	100	0.000	0.000	47	40	-7
LNG Spring	948.413	100	412.297	412.297	0.000	0.000	948.413	100	0.000	0.000	5868	5520	-348
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	173	173	0
LPG Meadow	70.749	100	0.000	0.000	0.000	0.000	70.749	100	0.000	0.000	942	942	0
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	289	289	0
DTI GSS TET	1441.753	100	1439.170	1418.446	0.000	20.724	1441.753	100	0.000	0.000	4259	3222	-1037
Enbridge 16	1600.000	100	1447.082	1438.400	0.000	8.682	1600.000	100	8.630	0.000	7976	5057	-2919
Enbridge 18	1820.000	100	1712.253	1701.980	0.000	10.274	1820.000	100	10.212	0.000	9149	5631	-3518
Nat Fuel FSS	1100.000	100	1060.743	1055.970	0.000	4.773	1100.000	100	4.752	0.000	5454	3013	-2441
TETCO FSS-1	63.360	100	63.717	63.360	0.000	0.357	63.360	100	0.355	0.000	277	141	-136
TETCO SS-1	1588.950	100	1503.096	1494.679	0.000	8.417	1588.950	100	11.808	0.000	4838	3582	-1256
TGP FSMA	1222.594	100	1238.572	1222.594	0.000	15.978	1222.594	100	0.000	0.000	6133	2680	-3452
Total	10641.528	100	9113.776	9044.571	0.000	69.205	10641.528	100	35.757	0.000	50004	34703	-15301

NOV 2023 thru OCT 2024 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2732.935	49.193	2683.742	5856.000	3172.258	9	3939	0	3947	1.4443
TCPL 63398	1874.426	16.870	1857.556	9538.692	7681.136	6	3115	0	3121	1.6649
TCPL 64198	6906.710	124.321	6782.389	21896.682	15114.293	22	11932	0	11954	1.7308
Union 12292	6507.548	28.633	6478.914	21795.300	15316.386	21	2133	0	2154	0.3310
Union 12204	2312.396	10.175	2302.222	9644.832	7342.610	7	944	0	951	0.4114
GS 23-001	1468.460	5.140	1463.320	2184.000	720.680	2	443	0	445	0.3033
PNG 233301 D	109.366	0.306	109.060	3409.800	3300.740	0	2593	0	2593	23.7074
PNG 233301 U	1472.583	4.123	1468.460	1824.000	355.540	2	1394	0	1396	0.9481
PNG 208535 D	3306.162	0.000	3306.162	8601.000	5294.838	5	6557	0	6561	1.9846
PNG 208535 H	2705.095	0.000	2705.095	8052.000	5346.905	4	6138	0	6142	2.2706
PNG 208540	1872.926	0.000	1872.926	5856.000	3983.074	3	3504	0	3507	1.8724
IGT RTS	1857.556	0.000	1857.556	10555.440	8697.884	9	1564	0	1573	0.8470
N Fuel FST I	1069.513	8.770	1060.743	3660.000	2599.257	16	0	0	16	0.0154
N Fuel FST W	1051.218	8.620	1042.598	3660.000	2617.402	16	602	0	618	0.5881
MLP 217524	3173.641	21.898	3151.743	5490.000	2338.257	11	3626	0	3637	1.1461
TGP 95349	374.570	3.034	371.536	3577.284	3205.748	29	714	0	744	1.9850
TGP 5173	2849.303	32.197	2817.105	4665.768	1848.663	292	2793	0	3086	1.0830
TGP 5293	4644.687	52.485	4592.202	4592.202	0.000	477	1043	0	1520	0.3273
TGP 5196	2722.523	30.765	2691.758	5627.250	2935.492	279	1279	0	1558	0.5723
TGP 5196 Wth	1679.925	0.000	1679.925	2013.000	333.075	3	0	0	3	0.0015
TGP 5291 Sup	2231.882	0.000	2231.882	2258.586	26.704	3	0	0	3	0.0015
TGP 5291 5-6	1155.588	9.360	1146.228	2258.586	1112.358	90	451	0	541	0.4682
TGP 5291 NF	1076.294	6.781	1069.513	2258.586	1189.073	68	0	0	68	0.0630
TGP Pool Law	4271.024	0.000	4271.024	13764.528	9493.504	0	0	0	0	0.0000
TGP Pool Spr	7347.806	0.000	7347.806	16259.184	8911.378	0	0	0	0	0.0000
TGP 39741	818.301	6.628	811.673	1493.646	681.973	64	298	0	362	0.4424
TGP 41098	1482.986	12.012	1470.974	6856.278	5385.304	115	1369	0	1485	1.0011
TGP 98775 Up	840.239	0.000	840.239	2232.600	1392.361	0	0	0	0	0.0000
TGP 98775 Br	491.281	1.130	490.151	2196.000	1705.849	16	0	0	16	0.0324
TGP 98775 Sp	348.958	0.803	348.155	2232.600	1884.445	11	2007	0	2019	5.7844
TGP 330904 L	2705.095	6.222	2698.873	8052.000	5353.127	88	3808	0	3896	1.4403
TGP 330904 S	5960.522	13.709	5946.813	27230.400	21283.587	193	12880	0	13073	2.1932
TGP 48427	116.446	0.268	116.178	6222.000	6105.822	4	826	0	829	7.1230
TGP 362252	116.178	0.267	115.911	5124.000	5008.089	4	365	0	369	3.1774
TGP to AGT	500.223	0.000	500.223	2196.000	1695.777	0	0	0	0	0.0000
Unitil X Bro	501.472	0.000	501.472	2004.582	1503.110	0	0	0	0	0.0000
Unitil X Law	756.453	0.000	756.453	1866.234	1109.781	0	0	0	0	0.0000
Unitil X Spr	205.395	0.000	205.395	505.812	300.417	0	0	0	0	0.0000

NOV 2023 thru OCT 2024 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT AIM	6600.162	188.822	6411.340	10980.000	4568.660	176	15043	0	15219	2.3058
AGT 93001EC	9837.221	42.792	9794.429	15518.982	5724.553	384	5324	0	5708	0.5802
AGT 93401	733.929	3.005	730.924	2082.540	1351.616	29	587	0	615	0.8384
AGT 93001F	1470.974	5.001	1465.972	6767.340	5301.368	57	1907	0	1964	1.3352
AGT Hubline	131.953	0.449	131.504	7320.000	7188.496	5	1679	0	1684	12.7635
AGT 510352	2248.335	8.201	2240.134	17568.000	15327.866	88	4949	0	5037	2.2404
AGT 93201 Ce	36.469	0.124	36.345	458.964	422.619	1	129	0	131	3.5847
AGT 93201 La	530.239	2.158	528.081	1550.010	1021.929	21	437	0	457	0.8626
AGT 94501	1405.953	5.800	1400.152	5401.428	4001.276	55	1522	0	1577	1.1214
TET 800414	63.005	0.296	62.709	386.496	323.787	5	123	0	128	2.0331
TET 800462	7120.978	54.119	7066.859	13311.054	6244.195	845	10286	0	11132	1.5632
TET 800382	519.110	2.440	516.670	1550.010	1033.340	39	484	0	522	1.0062
TET Stor Inj	1571.527	4.715	1566.813	365634.000	364067.187	77	0	0	77	0.0489
GSS Stor Inj	1443.500	4.331	1439.170	365634.000	364194.830	71	0	0	71	0.0489
GSS AMA Tran	745.223	3.503	741.720	2383.026	1641.306	56	0	0	56	0.0747
TRANSCO FT	154.113	1.125	152.988	458.964	305.976	3	59	0	62	0.4000
Total		780.588				3780	118847		122627	1.0550

NOV 2024 thru OCT 2025 | Cost and Flow Summary | Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	158442	Injection Cost	188	Transportation Cost	3613	JAN 15, 2025	
Penalty Cost	0	Withdrawal Cost	226	Other Variable Cost	120	System Served	417.063
Other Variable Cost	0	Carrying Cost	0			System Unserved	0.000
		Other Variable Cost	0			Total	417.063
Total Variable	158442	Total Variable	415	Total Variable	3732		
Demand/Reservation Co	1.912e7	Demand Cost	3193	Demand Cost	118847		
Other Fixed Cost	0	Other Fixed Cost	5160	Other Fixed Cost	0		
Total Fixed	1.912e7	Total Fixed	8353	Total Fixed	118847		
Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0		
Net Supply Cost	1.928e7	Net Storage Cost	8767	Net Trans Cost	122579	Total Gas Cost	19417621
						Total Revenue	0
						Net Cost	19417621

Avg Cost of Served Demand 418.5 USD/DT (System Cost/Served Dem.)
Avg Cost of Gas Purchased 408.4 USD/DT (Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	46391.270	0.000	46391.270	0.000	46391.270	46391.270	0.000	0	417.063	0.000
Total	46391.270	0.000	46391.270	0.000	46391.270	46391.270	0.000	0	417.063	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	130.122	364635.000	364504.878			14.8671	1935	0	1935	14.8671
Centerville	3202.926	364635.000	361432.074			4.1054	13149	0	13149	4.1054
Dawn	11502.178	364635.000	353132.822			3.7493	43126	0	43126	3.7493
Dracut	96.757	364635.000	364538.243			8.0753	781	0	781	8.0753
TGP Z4 313	6412.954	364635.000	358222.046			2.6560	17033	0	17033	2.6560
TGP Z4 200	2823.732	364635.000	361811.268			3.3938	9583	0	9583	3.3938
Hereford	0.000	364635.000	364635.000			0.0000	0	0	0	0.0000
LNG Inject	612.485	364635.000	364022.515			5.6100	3436	0	3436	5.6100
LPG Inject	0.000	364635.000	364635.000			0.0000	0	0	0	0.0000

NOV 2024 thru OCT 2025 Cost and Flow Summary Units: MDT, USD (000)

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Millennium	2748.968	364635.000	361886.032			3.2379	8901	0	8901	3.2379
Niagara	3027.672	364635.000	361607.328			3.2961	9980	0	9980	3.2961
Ramapo	3694.223	364635.000	360940.777			2.8833	10651	0	10651	2.8833
Repsol 30	987.000	987.000	0.000			3.2614	3219	13029226	13032445	13204.0983
Repsol 40	564.000	564.000	0.000			3.2614	1839	6098606	6100445	10816.3926
TETCO M2	9882.842	364635.000	354752.158			2.9853	29503	0	29503	2.9853
TETCO M3	1530.492	364635.000	363104.508			3.4670	5306	0	5306	3.4670
Winter AGT	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Winter TGP	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Total	47216.350						158442	19127832	19286274	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	731.704	100	182.075	204.026	0.000	0.000	709.753	97	0.000	-21.951	4351	4164	-187
LNG Lawrence	11.628	100	24.471	24.820	0.000	0.000	11.279	97	0.000	-0.349	62	65	3
LNG Marshfld	7.622	100	13.465	13.694	0.000	0.000	7.393	97	0.000	-0.229	40	42	2
LNG Spring	948.413	100	392.473	420.925	0.000	0.000	919.961	97	0.000	-28.452	5520	5286	-233
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	173	173	0
LPG Meadow	70.749	100	0.000	0.000	0.000	0.000	70.749	100	0.000	0.000	942	942	0
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	289	289	0
DTI GSS TET	1441.753	100	1429.736	1409.148	0.000	20.588	1441.753	100	0.000	0.000	3222	3625	402
Enbridge 16	1600.000	100	1537.223	1528.000	0.000	9.223	1600.000	100	9.168	0.000	5057	5420	363
Enbridge 18	1820.000	100	1784.764	1774.055	0.000	10.709	1820.000	100	10.644	0.000	5631	6174	543
Nat Fuel FSS	1100.000	100	1068.106	1063.300	0.000	4.806	1100.000	100	4.785	0.000	3013	3341	329
TETCO FSS-1	63.360	100	63.717	63.360	0.000	0.357	63.360	100	0.355	0.000	141	159	19
TETCO SS-1	1588.950	100	1503.096	1494.679	0.000	8.417	1588.950	100	11.808	0.000	3582	3955	373
TGP FSMA	1222.594	100	1238.572	1222.594	0.000	15.978	1222.594	100	0.000	0.000	2680	3058	377
Total	10641.528	100	9237.699	9218.601	0.000	70.078	10590.547	100	36.760	-50.981	34703	36693	1990

NOV 2024 thru OCT 2025 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2717.519	48.915	2668.604	5840.000	3171.396	9	3939	0	3947	1.4525
TCPL 63398	1840.243	16.562	1823.681	9512.630	7688.949	6	3115	0	3121	1.6958
TCPL 64198	6866.193	123.591	6742.602	21836.855	15094.253	22	11932	0	11954	1.7410
Union 12292	6379.914	28.072	6351.842	21735.750	15383.908	20	2133	0	2154	0.3376
Union 12204	2365.000	10.406	2354.594	9618.480	7263.886	8	944	0	952	0.4024
GS 23-001	1451.421	5.080	1446.341	2172.000	725.659	2	443	0	445	0.3069
PNG 233301 D	106.373	0.298	106.075	3407.500	3301.425	0	2593	0	2593	24.3745
PNG 233301 U	1455.496	4.075	1451.421	1812.000	360.579	2	1394	0	1396	0.9592
PNG 208535 D	3265.166	0.000	3265.166	8577.500	5312.334	5	6557	0	6561	2.0095
PNG 208535 H	2781.925	0.000	2781.925	8030.000	5248.075	4	6138	0	6142	2.2079
PNG 208540	1802.246	0.000	1802.246	5840.000	4037.754	3	3504	0	3507	1.9457
IGT RTS	1823.681	0.000	1823.681	10526.600	8702.919	9	1564	0	1573	0.8626
N Fuel FST I	1076.937	8.831	1068.106	3650.000	2581.894	17	0	0	17	0.0154
N Fuel FST W	1058.515	8.680	1049.835	3650.000	2600.165	16	602	0	618	0.5842
MLP 217524	2748.968	18.968	2730.000	5475.000	2745.000	9	3626	0	3636	1.3226
TGP 95349	366.823	2.971	363.852	3567.510	3203.658	29	714	0	743	2.0252
TGP 5173	2823.732	31.908	2791.824	4653.020	1861.196	290	2793	0	3083	1.0919
TGP 5293	4631.997	52.342	4579.655	4579.655	0.000	475	1043	0	1519	0.3279
TGP 5196	2814.815	31.807	2783.008	5611.875	2828.867	289	1279	0	1567	0.5569
TGP 5196 Wth	1764.980	0.000	1764.980	2007.500	242.520	3	0	0	3	0.0015
TGP 5291 Sup	2219.301	0.000	2219.301	2252.415	33.114	3	0	0	3	0.0015
TGP 5291 5-6	1135.536	9.198	1126.338	2252.415	1126.077	88	451	0	539	0.4750
TGP 5291 NF	1083.765	6.828	1076.937	2252.415	1175.478	68	0	0	68	0.0630
TGP Pool Law	4065.374	0.000	4065.374	13726.920	9661.546	0	0	0	0	0.0000
TGP Pool Spr	7579.303	0.000	7579.303	16214.760	8635.457	0	0	0	0	0.0000
TGP 39741	808.370	6.548	801.823	1489.565	687.742	63	298	0	361	0.4468
TGP 41098	1456.858	11.801	1445.058	6837.545	5392.487	113	1369	0	1483	1.0176
TGP 98775 Up	861.041	0.000	861.041	2226.500	1365.459	0	0	0	0	0.0000
TGP 98775 Br	486.799	1.120	485.679	2190.000	1704.321	16	0	0	16	0.0324
TGP 98775 Sp	374.243	0.861	373.382	2226.500	1853.118	12	2007	0	2019	5.3958
TGP 330904 L	2781.925	6.398	2775.527	8030.000	5254.473	90	3808	0	3899	1.4014
TGP 330904 S	5819.661	13.385	5806.276	27156.000	21349.724	189	12880	0	13068	2.2455
TGP 48427	140.541	0.323	140.218	6205.000	6064.782	5	826	0	830	5.9074
TGP 362252	140.218	0.323	139.895	5110.000	4970.105	5	365	0	370	2.6382
TGP to AGT	585.367	0.000	585.367	2190.000	1604.633	0	0	0	0	0.0000
Unitil X Bro	491.444	0.000	491.444	1999.105	1507.661	0	0	0	0	0.0000
Unitil X Law	751.743	0.000	751.743	1861.135	1109.392	0	0	0	0	0.0000
Unitil X Spr	203.154	0.000	203.154	504.430	301.276	0	0	0	0	0.0000

NOV 2024 thru OCT 2025 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT AIM	6424.223	185.335	6238.888	10950.000	4711.112	171	15043	0	15214	2.3682
AGT 93001EC	8640.260	36.014	8604.246	15467.350	6863.104	337	5324	0	5661	0.6552
AGT 93401	684.588	2.726	681.862	2076.850	1394.988	27	587	0	613	0.8961
AGT 93001F	1445.058	4.913	1440.144	6748.850	5308.706	56	1907	0	1963	1.3584
AGT Hubline	130.122	0.442	129.680	7300.000	7170.320	5	1679	0	1684	12.9424
AGT 510352	3306.107	14.452	3291.655	17520.000	14228.345	129	4949	0	5078	1.5361
AGT 93201 Ce	48.553	0.195	48.358	457.710	409.352	2	129	0	131	2.7022
AGT 93201 La	485.883	1.917	483.966	1545.775	1061.809	19	437	0	456	0.9378
AGT 94501	1340.743	5.337	1335.406	5386.670	4051.264	52	1522	0	1574	1.1740
TET 800414	63.005	0.296	62.709	385.440	322.731	5	123	0	128	2.0331
TET 800462	6877.276	52.267	6825.009	13274.685	6449.676	816	10286	0	11103	1.6144
TET 800382	510.363	2.399	507.964	1545.775	1037.811	38	484	0	522	1.0221
TET Stor Inj	1571.527	4.715	1566.813	364635.000	363068.187	77	0	0	77	0.0489
GSS Stor Inj	1434.038	4.302	1429.736	364635.000	363205.264	70	0	0	70	0.0489
GSS AMA Tran	745.935	3.506	742.429	2376.515	1634.086	56	0	0	56	0.0747
TRANSCO FT	152.850	1.116	151.734	457.710	305.976	3	59	0	62	0.4031
Total		769.223				3732	118847		122579	1.0660

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	167914	Injection Cost	191	Transportation Cost	3333	JAN 15, 2026	
Penalty Cost	0	Withdrawal Cost	229	Other Variable Cost	114	System Served	419.188
Other Variable Cost	0	Carrying Cost	0			System Unserved	0.000
		Other Variable Cost	0			Total	419.188
Total Variable	167914	Total Variable	420	Total Variable	3447		
Demand/Reservation Co	1.912e7	Demand Cost	3193	Demand Cost	118847		
Other Fixed Cost	0	Other Fixed Cost	5160	Other Fixed Cost	0		
Total Fixed	1.912e7	Total Fixed	8353	Total Fixed	118847		
Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0		
Net Supply Cost	1.929e7	Net Storage Cost	8773	Net Trans Cost	122294	Total Gas Cost	19426812
						Total Revenue	0
						Net Cost	19426812

Avg Cost of Served Demand 414.1 USD/DT
(System Cost/Served Dem.)

Avg Cost of Gas Purchased 404.1 USD/DT
(Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	46912.199	0.000	46912.199	0.000	46912.199	46912.199	0.000	0	419.188	0.000
Total	46912.199	0.000	46912.199	0.000	46912.199	46912.199	0.000	0	419.188	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	133.622	364635.000	364501.378			15.0873	2016	0	2016	15.0873
Centerville	4875.209	364635.000	359759.791			3.6769	17926	0	17926	3.6769
Dawn	10732.113	364635.000	353902.887			4.1128	44139	0	44139	4.1128
Dracut	799.494	364635.000	363835.506			3.8083	3045	0	3045	3.8083
TGP Z4 313	6539.583	364635.000	358095.417			2.6364	17241	0	17241	2.6364
TGP Z4 200	2839.896	364635.000	361795.104			3.5685	10134	0	10134	3.5685
Hereford	0.211	364635.000	364634.789			3.4240	1	0	1	3.4240
LNG Inject	677.054	364635.000	363957.946			5.5867	3783	0	3783	5.5867
LPG Inject	0.000	364635.000	364635.000			0.0000	0	0	0	0.0000

Scenario 2266
EGMA F&SP 2023 - Normal Weather - Draw 0

Ventyx
SENDOUT® Version 14.3.0
Report 1 (Continued)

NOV 2025 thru OCT 2026

Cost and Flow Summary

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Millennium	1359.380	364635.000	363275.620			3.9607	5384	0	5384	3.9607
Niagara	3004.342	364635.000	361630.658			3.4146	10259	0	10259	3.4146
Ramapo	4442.361	364635.000	360192.639			3.0199	13415	0	13415	3.0199
Repsol 30	987.000	987.000	0.000			3.7089	3661	13029226	13032887	13204.5457
Repsol 40	564.000	564.000	0.000			3.7089	2092	6098606	6100698	10816.8401
TETCO M2	7319.261	364635.000	357315.739			3.1618	23142	0	23142	3.1618
TETCO M3	3466.474	364635.000	361168.526			3.3686	11677	0	11677	3.3686
Winter AGT	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Winter TGP	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Total	47740.000						167914	19127832	19295746	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	709.753	97	202.254	202.254	0.000	0.000	709.753	97	0.000	0.000	4164	4112	-52
LNG Lawrence	11.279	97	24.820	24.820	0.000	0.000	11.279	97	0.000	0.000	65	64	-0
LNG Marshfld	7.393	97	13.465	13.465	0.000	0.000	7.393	97	0.000	0.000	42	42	-0
LNG Spring	919.961	97	436.515	436.515	0.000	0.000	919.961	97	0.000	0.000	5286	5229	-57
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	173	173	0
LPG Meadow	70.749	100	0.000	0.000	0.000	0.000	70.749	100	0.000	0.000	942	942	0
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	289	289	0
DTI GSS TET	1441.753	100	1462.818	1441.753	0.000	21.065	1441.753	100	0.000	0.000	3625	3487	-137
Enbridge 16	1600.000	100	1537.091	1527.869	0.000	9.223	1600.000	100	9.167	0.000	5420	5574	154
Enbridge 18	1820.000	100	1792.228	1781.475	0.000	10.753	1820.000	100	10.689	0.000	6174	6349	175
Nat Fuel FSS	1100.000	100	1104.922	1099.950	0.000	4.972	1100.000	100	4.950	0.000	3341	3227	-114
TETCO FSS-1	63.360	100	63.717	63.360	0.000	0.357	63.360	100	0.355	0.000	159	153	-7
TETCO SS-1	1588.950	100	1503.096	1494.679	0.000	8.417	1588.950	100	11.808	0.000	3955	3816	-139
TGP FSMA	1222.594	100	1238.572	1222.594	0.000	15.978	1222.594	100	0.000	0.000	3058	2908	-149
Total	10590.547	100	9379.498	9308.733	0.000	70.764	10590.547	100	36.969	0.000	36693	36366	-326

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2385.310	42.936	2342.374	5840.000	3497.626	7	3939	0	3946	1.6544
TCPL 63398	1738.918	15.650	1723.268	9512.630	7789.362	6	3115	0	3120	1.7944
TCPL 64198	6531.502	117.567	6413.935	21836.855	15422.920	21	11932	0	11953	1.8300
Union 12292	6599.077	29.036	6570.041	21735.750	15165.709	21	2133	0	2154	0.3265
Union 12204	1707.894	7.515	1700.379	9618.480	7918.101	5	944	0	949	0.5559
GS 23-001	1448.085	5.068	1443.016	2172.000	728.984	2	443	0	445	0.3076
PNG 233301 D	109.303	0.306	108.997	3407.500	3298.503	0	2593	0	2593	23.7210
PNG 233301 U	1452.151	4.066	1448.085	1812.000	363.915	2	1394	0	1396	0.9614
PNG 208535 D	2916.106	0.000	2916.106	8577.500	5661.394	4	6557	0	6561	2.2499
PNG 208535 H	2589.546	0.000	2589.546	8030.000	5440.454	4	6138	0	6142	2.3718
PNG 208540	1689.414	0.000	1689.414	5840.000	4150.586	3	3504	0	3507	2.0756
IGT RTS	1723.268	0.000	1723.268	10526.600	8803.332	8	1564	0	1573	0.9126
N Fuel FST I	1114.057	9.135	1104.922	3650.000	2545.078	17	0	0	17	0.0154
N Fuel FST W	1095.000	8.979	1086.021	3650.000	2563.979	17	602	0	619	0.5652
MLP 217524	1359.380	9.380	1350.000	5475.000	4125.000	5	3626	0	3631	2.6711
TGP 95349	412.426	3.341	409.085	3567.510	3158.425	32	714	0	746	1.8099
TGP 5173	2839.896	32.091	2807.805	4653.020	1845.215	291	2793	0	3085	1.0863
TGP 5293	4631.997	52.342	4579.655	4579.655	0.000	475	1043	0	1519	0.3279
TGP 5196	2977.630	33.647	2943.983	5611.875	2667.892	306	1279	0	1584	0.5320
TGP 5196 Wth	1891.609	0.000	1891.609	2007.500	115.891	3	0	0	3	0.0015
TGP 5291 Sup	2189.879	0.000	2189.879	2252.415	62.536	3	0	0	3	0.0015
TGP 5291 5-6	1068.758	8.657	1060.101	2252.415	1192.314	83	451	0	534	0.4999
TGP 5291 NF	1121.120	7.063	1114.057	2252.415	1138.358	71	0	0	71	0.0630
TGP Pool Law	4304.773	0.000	4304.773	13726.920	9422.147	0	0	0	0	0.0000
TGP Pool Spr	7495.856	0.000	7495.856	16214.760	8718.904	0	0	0	0	0.0000
TGP 39741	814.463	6.597	807.866	1489.565	681.699	63	298	0	362	0.4441
TGP 41098	1310.842	10.618	1300.224	6837.545	5537.321	102	1369	0	1471	1.1223
TGP 98775 Up	846.947	0.000	846.947	2226.500	1379.553	0	0	0	0	0.0000
TGP 98775 Br	441.263	1.015	440.248	2190.000	1749.752	14	0	0	14	0.0324
TGP 98775 Sp	405.684	0.933	404.751	2226.500	1821.749	13	2007	0	2020	4.9801
TGP 330904 L	2589.546	5.956	2583.590	8030.000	5446.410	84	3808	0	3892	1.5031
TGP 330904 S	6069.291	13.959	6055.332	27156.000	21100.668	197	12880	0	13076	2.1545
TGP 48427	148.774	0.342	148.432	6205.000	6056.568	5	826	0	830	5.5823
TGP 362252	148.432	0.341	148.090	5110.000	4961.910	5	365	0	370	2.4941
TGP to AGT	604.381	0.000	604.381	2190.000	1585.619	0	0	0	0	0.0000
Unitil X Bro	486.604	0.000	486.604	1999.105	1512.501	0	0	0	0	0.0000
Unitil X Law	753.259	0.000	753.259	1861.135	1107.876	0	0	0	0	0.0000
Unitil X Spr	203.154	0.000	203.154	504.430	301.276	0	0	0	0	0.0000

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT AIM	5792.361	173.184	5619.178	10950.000	5330.822	154	15043	0	15197	2.6236
AGT 93001EC	8099.669	32.887	8066.782	15467.350	7400.568	316	5324	0	5640	0.6963
AGT 93401	662.679	2.591	660.088	2076.850	1416.762	26	587	0	613	0.9244
AGT 93001F	1300.224	4.421	1295.804	6748.850	5453.046	51	1907	0	1957	1.5054
AGT Hubline	133.622	0.454	133.168	7300.000	7166.832	5	1679	0	1684	12.6045
AGT 510352	4987.749	23.774	4963.975	17520.000	12556.025	195	4949	0	5144	1.0313
AGT 93201 Ce	66.080	0.280	65.800	457.710	391.910	3	129	0	132	1.9958
AGT 93201 La	477.447	1.848	475.598	1545.775	1070.177	19	437	0	455	0.9537
AGT 94501	1276.132	4.900	1271.231	5386.670	4115.439	50	1522	0	1572	1.2315
TET 800414	63.005	0.296	62.709	385.440	322.731	5	123	0	128	2.0331
TET 800462	4280.514	32.532	4247.982	13274.685	9026.703	508	10286	0	10794	2.5218
TET 800382	518.873	2.439	516.434	1545.775	1029.341	39	484	0	522	1.0066
TET Stor Inj	1571.527	4.715	1566.813	364635.000	363068.187	77	0	0	77	0.0489
GSS Stor Inj	1467.219	4.402	1462.818	364635.000	363172.182	72	0	0	72	0.0489
GSS AMA Tran	742.947	3.492	739.455	2376.515	1637.060	56	0	0	56	0.0747
TRANSCO FT	179.933	1.314	178.619	457.710	279.091	3	59	0	62	0.3454
Total		720.067				3447	118847		122294	1.1134

Scenario 2266
EGMA F&SP 2023 - Normal Weather - Draw 0

Ventyx
SENDOUT® Version 14.3.0
Report 1

NOV 2026 thru OCT 2027

Cost and Flow Summary

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	171416	Injection Cost	191	Transportation Cost	3651	JAN 15, 2027	
Penalty Cost	0	Withdrawal Cost	229	Other Variable Cost	120	System Served	426.222
Other Variable Cost	0	Carrying Cost	0			System Unserved	0.000
		Other Variable Cost	0			Total	426.222
Total Variable	171416	Total Variable	420	Total Variable	3771		
Demand/Reservation Co	1.912e7	Demand Cost	3193	Demand Cost	118847		
Other Fixed Cost	0	Other Fixed Cost	5160	Other Fixed Cost	0		
Total Fixed	1.912e7	Total Fixed	8353	Total Fixed	118847		
Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0		
Net Supply Cost	1.929e7	Net Storage Cost	8773	Net Trans Cost	122618	Total Gas Cost	19430639
						Total Revenue	0
						Net Cost	19430639

Avg Cost of Served Demand 403.8 USD/DT
(System Cost/Served Dem.)

Avg Cost of Gas Purchased 394.1 USD/DT
(Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	48111.582	0.000	48111.582	0.000	48111.582	48111.582	0.000	0	426.222	0.000
Total	48111.582	0.000	48111.582	0.000	48111.582	48111.582	0.000	0	426.222	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	141.679	364635.000	364493.321			15.6018	2210	0	2210	15.6018
Centerville	3907.631	364635.000	360727.369			4.4852	17527	0	17527	4.4852
Dawn	11032.140	364635.000	353602.860			4.1943	46272	0	46272	4.1943
Dracut	868.387	364635.000	363766.613			3.7725	3276	0	3276	3.7725
TGP Z4 313	6523.708	364635.000	358111.292			2.5588	16693	0	16693	2.5588
TGP Z4 200	2895.203	364635.000	361739.797			3.5353	10235	0	10235	3.5353
Hereford	1.429	364635.000	364633.571			3.3880	5	0	5	3.3880
LNG Inject	722.503	364635.000	363912.497			5.5617	4018	0	4018	5.5617
LPG Inject	0.000	364635.000	364635.000			0.0000	0	0	0	0.0000

Scenario 2266
EGMA F&SP 2023 - Normal Weather - Draw 0

Ventyx
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Report 1 (Continued)

NOV 2026 thru OCT 2027

Cost and Flow Summary

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Millennium	1948.572	364635.000	362686.428			3.6005	7016	0	7016	3.6005
Niagara	3033.811	364635.000	361601.189			3.3581	10188	0	10188	3.3581
Ramapo	3670.455	364635.000	360964.545			2.9295	10753	0	10753	2.9295
Repsol 30	987.000	987.000	0.000			3.6893	3641	13029226	13032867	13204.5262
Repsol 40	564.000	564.000	0.000			3.6893	2081	6098606	6100687	10816.8205
TETCO M2	9526.708	364635.000	355108.292			2.8812	27448	0	27448	2.8812
TETCO M3	3147.006	364635.000	361487.994			3.1943	10053	0	10053	3.1943
Winter AGT	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Winter TGP	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Total	48970.233						171416	19127832	19299248	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	709.753	97	236.542	236.542	0.000	0.000	709.753	97	0.000	0.000	4112	4061	-51
LNG Lawrence	11.279	97	26.473	26.473	0.000	0.000	11.279	97	0.000	0.000	64	64	-0
LNG Marshfld	7.393	97	13.465	13.465	0.000	0.000	7.393	97	0.000	0.000	42	42	-0
LNG Spring	919.961	97	446.023	446.023	0.000	0.000	919.961	97	0.000	0.000	5229	5186	-43
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	173	173	0
LPG Meadow	70.749	100	0.000	0.000	0.000	0.000	70.749	100	0.000	0.000	942	942	0
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	289	289	0
DTI GSS TET	1441.753	100	1462.818	1441.753	0.000	21.065	1441.753	100	0.000	0.000	3487	3393	-95
Enbridge 16	1600.000	100	1534.326	1525.120	0.000	9.206	1600.000	100	9.151	0.000	5574	5587	13
Enbridge 18	1820.000	100	1806.891	1796.050	0.000	10.841	1820.000	100	10.776	0.000	6349	6362	13
Nat Fuel FSS	1100.000	100	1104.922	1099.950	0.000	4.972	1100.000	100	4.950	0.000	3227	3092	-135
TETCO FSS-1	63.360	100	63.717	63.360	0.000	0.357	63.360	100	0.355	0.000	153	149	-4
TETCO SS-1	1588.950	100	1503.096	1494.679	0.000	8.417	1588.950	100	11.808	0.000	3816	3709	-106
TGP FSMA	1222.594	100	1238.572	1222.594	0.000	15.978	1222.594	100	0.000	0.000	2908	2771	-137
Total	10590.547	100	9436.845	9366.009	0.000	70.836	10590.547	100	37.040	0.000	36366	35820	-546

NOV 2026 thru OCT 2027 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2381.775	42.872	2338.903	5840.000	3501.097	7	3939	0	3946	1.6568
TCPL 63398	1856.934	16.712	1840.222	9512.630	7672.408	6	3115	0	3121	1.6806
TCPL 64198	6715.571	120.880	6594.690	21836.855	15242.165	21	11932	0	11953	1.7799
Union 12292	6712.780	29.536	6683.244	21735.750	15052.506	21	2133	0	2155	0.3210
Union 12204	1897.610	8.349	1889.261	9618.480	7729.219	6	944	0	950	0.5007
GS 23-001	1458.563	5.105	1453.458	2172.000	718.542	2	443	0	445	0.3054
PNG 233301 D	134.173	0.376	133.798	3407.500	3273.702	0	2593	0	2593	19.3244
PNG 233301 U	1462.658	4.095	1458.563	1812.000	353.437	2	1394	0	1396	0.9545
PNG 208535 D	2979.920	0.000	2979.920	8577.500	5597.580	4	6557	0	6561	2.2017
PNG 208535 H	2544.969	0.000	2544.969	8030.000	5485.031	4	6138	0	6142	2.4133
PNG 208540	1813.302	0.000	1813.302	5840.000	4026.698	3	3504	0	3507	1.9339
IGT RTS	1840.222	0.000	1840.222	10526.600	8686.378	9	1564	0	1573	0.8549
N Fuel FST I	1114.057	9.135	1104.922	3650.000	2545.078	17	0	0	17	0.0154
N Fuel FST W	1095.000	8.979	1086.021	3650.000	2563.979	17	602	0	619	0.5652
MLP 217524	1948.572	13.445	1935.127	5475.000	3539.873	7	3626	0	3633	1.8645
TGP 95349	442.710	3.586	439.124	3567.510	3128.386	34	714	0	749	1.6914
TGP 5173	2895.203	32.716	2862.487	4653.020	1790.533	297	2793	0	3091	1.0675
TGP 5293	4631.997	52.342	4579.655	4579.655	0.000	475	1043	0	1519	0.3279
TGP 5196	2961.755	33.468	2928.287	5611.875	2683.588	304	1279	0	1583	0.5343
TGP 5196 Wth	1875.734	0.000	1875.734	2007.500	131.766	3	0	0	3	0.0015
TGP 5291 Sup	2206.029	0.000	2206.029	2252.415	46.386	3	0	0	3	0.0015
TGP 5291 5-6	1084.909	8.788	1076.121	2252.415	1176.294	84	451	0	535	0.4936
TGP 5291 NF	1121.120	7.063	1114.057	2252.415	1138.358	71	0	0	71	0.0630
TGP Pool Law	4521.326	0.000	4521.326	13726.920	9205.594	0	0	0	0	0.0000
TGP Pool Spr	7364.348	0.000	7364.348	16214.760	8850.412	0	0	0	0	0.0000
TGP 39741	827.782	6.705	821.077	1489.565	668.488	64	298	0	363	0.4382
TGP 41098	1397.512	11.320	1386.192	6837.545	5451.353	109	1369	0	1478	1.0575
TGP 98775 Up	831.528	0.000	831.528	2226.500	1394.972	0	0	0	0	0.0000
TGP 98775 Br	430.616	0.990	429.626	2190.000	1760.374	14	0	0	14	0.0324
TGP 98775 Sp	400.912	0.922	399.989	2226.500	1826.511	13	2007	0	2020	5.0390
TGP 330904 L	2544.969	5.853	2539.116	8030.000	5490.884	83	3808	0	3891	1.5289
TGP 330904 S	6350.441	14.606	6335.835	27156.000	20820.165	206	12880	0	13085	2.0606
TGP 48427	164.438	0.378	164.060	6205.000	6040.940	5	826	0	831	5.0536
TGP 362252	164.060	0.377	163.683	5110.000	4946.317	5	365	0	371	2.2596
TGP to AGT	506.358	0.000	506.358	2190.000	1683.642	0	0	0	0	0.0000
Unitil X Bro	494.541	0.000	494.541	1999.105	1504.564	0	0	0	0	0.0000
Unitil X Law	754.381	0.000	754.381	1861.135	1106.754	0	0	0	0	0.0000
Unitil X Spr	204.536	0.000	204.536	504.430	299.894	0	0	0	0	0.0000

NOV 2026 thru OCT 2027 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT AIM	5605.582	169.949	5435.633	10950.000	5514.367	149	15043	0	15192	2.7101
AGT 93001EC	9934.560	43.573	9890.987	15467.350	5576.363	388	5324	0	5712	0.5749
AGT 93401	696.175	2.685	693.490	2076.850	1383.360	27	587	0	614	0.8818
AGT 93001F	1386.192	4.713	1381.479	6748.850	5367.371	54	1907	0	1961	1.4145
AGT Hubline	141.679	0.482	141.197	7300.000	7158.803	6	1679	0	1685	11.8899
AGT 510352	4037.843	17.707	4020.136	17520.000	13499.864	158	4949	0	5107	1.2648
AGT 93201 Ce	49.111	0.205	48.906	457.710	408.804	2	129	0	131	2.6719
AGT 93201 La	457.856	1.772	456.084	1545.775	1089.691	18	437	0	455	0.9928
AGT 94501	1297.833	5.123	1292.710	5386.670	4093.960	51	1522	0	1572	1.2116
TET 800414	63.005	0.296	62.709	385.440	322.731	5	123	0	128	2.0331
TET 800462	6487.961	49.309	6438.653	13274.685	6836.032	770	10286	0	11056	1.7042
TET 800382	518.291	2.436	515.855	1545.775	1029.920	39	484	0	522	1.0076
TET Stor Inj	1571.527	4.715	1566.813	364635.000	363068.187	77	0	0	77	0.0489
GSS Stor Inj	1467.219	4.402	1462.818	364635.000	363172.182	72	0	0	72	0.0489
GSS AMA Tran	742.822	3.491	739.330	2376.515	1637.185	56	0	0	56	0.0747
TRANSCO FT	180.641	1.319	179.322	457.710	278.388	4	59	0	62	0.3441
Total		750.775				3771	118847		122618	1.0684

Scenario 2266
EGMA F&SP 2023 - Normal Weather - Draw 0

Ventyx
SENDOUT® Version 14.3.0
Report 1

NOV 2027 thru OCT 2028

Cost and Flow Summary

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	173273	Injection Cost	191	Transportation Cost	3827	JAN 15, 2028	
Penalty Cost	0	Withdrawal Cost	228	Other Variable Cost	123	System Served	432.083
Other Variable Cost	0	Carrying Cost	0			System Unserved	0.000
		Other Variable Cost	0			Total	432.083
Total Variable	173273	Total Variable	419	Total Variable	3951		
Demand/Reservation Co	1.912e7	Demand Cost	3193	Demand Cost	118847		
Other Fixed Cost	0	Other Fixed Cost	5160	Other Fixed Cost	0		
Total Fixed	1.912e7	Total Fixed	8353	Total Fixed	118847		
Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0		
Net Supply Cost	1.930e7	Net Storage Cost	8771	Net Trans Cost	122798	Total Gas Cost	19432674
						Total Revenue	0
						Net Cost	19432674

Avg Cost of Served Demand 396.1 USD/DT
(System Cost/Served Dem.)

Avg Cost of Gas Purchased 386.6 USD/DT
(Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	49050.534	0.000	49050.534	0.000	49050.534	49050.534	0.000	0	432.083	0.000
Total	49050.534	0.000	49050.534	0.000	49050.534	49050.534	0.000	0	432.083	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	148.106	365634.000	365485.894			15.6405	2316	0	2316	15.6405
Centerville	4836.126	365634.000	360797.874			4.3037	20813	0	20813	4.3037
Dawn	11202.520	365634.000	354431.480			4.1535	46530	0	46530	4.1535
Dracut	905.846	365634.000	364728.154			3.7630	3409	0	3409	3.7630
TGP Z4 313	6547.959	365634.000	359086.041			2.6128	17108	0	17108	2.6128
TGP Z4 200	2950.176	365634.000	362683.824			3.4513	10182	0	10182	3.4513
Hereford	2.385	365634.000	365631.615			3.3530	8	0	8	3.3530
LNG Inject	728.914	365634.000	364905.086			5.5420	4040	0	4040	5.5420
LPG Inject	0.000	365634.000	365634.000			0.0000	0	0	0	0.0000

Scenario 2266
EGMA F&SP 2023 - Normal Weather - Draw 0

Ventyx
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Report 1 (Continued)

NOV 2027 thru OCT 2028

Cost and Flow Summary

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Millennium	1969.274	365634.000	363664.726			3.6637	7215	0	7215	3.6637
Niagara	3091.857	365634.000	362542.143			3.3074	10226	0	10226	3.3074
Ramapo	3560.142	365634.000	362073.858			2.8426	10120	0	10120	2.8426
Repsol 30	987.000	987.000	0.000			3.6713	3624	13029226	13032850	13204.5082
Repsol 40	564.000	564.000	0.000			3.6713	2071	6098606	6100677	10816.8025
TETCO M2	10643.928	365634.000	354990.072			2.8237	30055	0	30055	2.8237
TETCO M3	1780.302	365634.000	363853.698			3.1215	5557	0	5557	3.1215
Winter AGT	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Winter TGP	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Total	49918.535						173273	19127832	19301105	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	709.753	97	231.232	231.232	0.000	0.000	709.753	97	0.000	0.000	4061	4022	-39
LNG Lawrence	11.279	97	26.473	26.473	0.000	0.000	11.279	97	0.000	0.000	64	64	-0
LNG Marshfld	7.393	97	14.455	14.455	0.000	0.000	7.393	97	0.000	0.000	42	42	-0
LNG Spring	919.961	97	456.754	456.754	0.000	0.000	919.961	97	0.000	0.000	5186	5152	-34
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	173	173	0
LPG Meadow	70.749	100	0.000	0.000	0.000	0.000	70.749	100	0.000	0.000	942	942	0
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	289	289	0
DTI GSS TET	1441.753	100	1444.686	1423.883	0.000	20.803	1441.753	100	0.000	0.000	3393	3460	67
Enbridge 16	1600.000	100	1534.326	1525.120	0.000	9.206	1600.000	100	9.151	0.000	5587	5565	-22
Enbridge 18	1820.000	100	1778.440	1767.770	0.000	10.671	1820.000	100	10.607	0.000	6362	6335	-28
Nat Fuel FSS	1100.000	100	1104.972	1100.000	0.000	4.972	1100.000	100	4.950	0.000	3092	3120	28
TETCO FSS-1	63.360	100	63.717	63.360	0.000	0.357	63.360	100	0.355	0.000	149	151	3
TETCO SS-1	1588.950	100	1503.096	1494.679	0.000	8.417	1588.950	100	11.808	0.000	3709	3793	84
TGP FSMA	1222.594	100	1238.572	1222.594	0.000	15.978	1222.594	100	0.000	0.000	2771	2912	141
Total	10590.547	100	9396.724	9326.319	0.000	70.404	10590.547	100	36.870	0.000	35820	36021	200

NOV 2027 thru OCT 2028 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2384.255	42.917	2341.338	5856.000	3514.662	7	3939	0	3946	1.6551
TCPL 63398	1869.601	16.826	1852.774	9538.692	7685.918	6	3115	0	3121	1.6692
TCPL 64198	6870.404	123.667	6746.737	21896.682	15149.945	22	11932	0	11954	1.7399
Union 12292	6802.389	29.931	6772.458	21795.300	15022.842	22	2133	0	2155	0.3168
Union 12204	1976.243	8.695	1967.547	9644.832	7677.285	6	944	0	950	0.4809
GS 23-001	1463.532	5.122	1458.409	2184.000	725.591	2	443	0	445	0.3044
PNG 233301 D	165.368	0.463	164.905	3409.800	3244.895	0	2593	0	2593	15.6794
PNG 233301 U	1467.641	4.109	1463.532	1824.000	360.468	2	1394	0	1396	0.9512
PNG 208535 D	3007.062	0.000	3007.062	8601.000	5593.938	5	6557	0	6561	2.1819
PNG 208535 H	2667.206	0.000	2667.206	8052.000	5384.794	4	6138	0	6142	2.3028
PNG 208540	1783.183	0.000	1783.183	5856.000	4072.817	3	3504	0	3507	1.9665
IGT RTS	1852.774	0.000	1852.774	10555.440	8702.666	9	1564	0	1573	0.8492
N Fuel FST I	1114.108	9.136	1104.972	3660.000	2555.028	17	0	0	17	0.0154
N Fuel FST W	1095.050	8.979	1086.071	3660.000	2573.929	17	602	0	619	0.5652
MLP 217524	1969.274	13.588	1955.686	5490.000	3534.314	7	3626	0	3633	1.8449
TGP 95349	461.579	3.739	457.840	3577.284	3119.444	36	714	0	750	1.6255
TGP 5173	2950.176	33.337	2916.839	4665.768	1748.929	303	2793	0	3096	1.0495
TGP 5293	4644.687	52.485	4592.202	4592.202	0.000	477	1043	0	1520	0.3273
TGP 5196	2973.365	33.599	2939.766	5627.250	2687.484	305	1279	0	1584	0.5326
TGP 5196 Wth	1887.294	0.000	1887.294	2013.000	125.706	3	0	0	3	0.0015
TGP 5291 Sup	2249.738	0.000	2249.738	2258.586	8.848	3	0	0	3	0.0015
TGP 5291 5-6	1128.567	9.141	1119.426	2258.586	1139.160	88	451	0	539	0.4775
TGP 5291 NF	1121.171	7.063	1114.108	2258.586	1144.478	71	0	0	71	0.0630
TGP Pool Law	4554.576	0.000	4554.576	13764.528	9209.952	0	0	0	0	0.0000
TGP Pool Spr	7471.496	0.000	7471.496	16259.184	8787.688	0	0	0	0	0.0000
TGP 39741	842.118	6.821	835.297	1493.646	658.349	66	298	0	364	0.4320
TGP 41098	1391.196	11.269	1379.927	6856.278	5476.351	108	1369	0	1477	1.0620
TGP 98775 Up	846.580	0.000	846.580	2232.600	1386.020	0	0	0	0	0.0000
TGP 98775 Br	432.451	0.995	431.457	2196.000	1764.543	14	0	0	14	0.0324
TGP 98775 Sp	414.129	0.952	413.177	2232.600	1819.423	13	2007	0	2021	4.8792
TGP 330904 L	2667.206	6.135	2661.072	8052.000	5390.928	86	3808	0	3895	1.4603
TGP 330904 S	6403.085	14.727	6388.358	27230.400	20842.042	208	12880	0	13087	2.0439
TGP 48427	162.331	0.373	161.957	6222.000	6060.043	5	826	0	831	5.1188
TGP 362252	161.957	0.373	161.585	5124.000	4962.415	5	365	0	371	2.2885
TGP to AGT	455.729	0.000	455.729	2196.000	1740.271	0	0	0	0	0.0000
Unitil X Bro	501.071	0.000	501.071	2004.582	1503.511	0	0	0	0	0.0000
Unitil X Law	755.567	0.000	755.567	1866.234	1110.667	0	0	0	0	0.0000
Unitil X Spr	201.772	0.000	201.772	505.812	304.040	0	0	0	0	0.0000

NOV 2027 thru OCT 2028 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT AIM	5515.828	162.977	5352.851	10980.000	5627.149	147	15043	0	15190	2.7538
AGT 93001EC	9917.203	43.818	9873.384	15518.982	5645.598	387	5324	0	5711	0.5759
AGT 93401	594.728	2.427	592.301	2082.540	1490.239	23	587	0	610	1.0256
AGT 93001F	1379.927	4.692	1375.235	6767.340	5392.105	54	1907	0	1960	1.4207
AGT Hubline	148.106	0.504	147.602	7320.000	7172.398	6	1679	0	1685	11.3757
AGT 510352	4896.259	20.406	4875.853	17568.000	12692.147	191	4949	0	5141	1.0499
AGT 93201 Ce	84.100	0.334	83.766	458.964	375.198	3	129	0	133	1.5765
AGT 93201 La	427.975	1.747	426.228	1550.010	1123.782	17	437	0	453	1.0594
AGT 94501	1223.987	5.014	1218.973	5401.428	4182.455	48	1522	0	1570	1.2823
TET 800414	63.005	0.296	62.709	386.496	323.787	5	123	0	128	2.0331
TET 800462	7623.367	57.938	7565.430	13311.054	5745.624	905	10286	0	11191	1.4680
TET 800382	516.448	2.427	514.021	1550.010	1035.989	39	484	0	522	1.0110
TET Stor Inj	1571.527	4.715	1566.813	365634.000	364067.187	77	0	0	77	0.0489
GSS Stor Inj	1449.033	4.347	1444.686	365634.000	364189.314	71	0	0	71	0.0489
GSS AMA Tran	762.141	3.582	758.559	2383.026	1624.467	57	0	0	57	0.0747
TRANSCO FT	145.293	1.061	144.233	458.964	314.731	3	59	0	61	0.4231
Total		760.726				3951	118847		122798	1.0452

Scenario 2266
EGMA F&SP 2023 - Normal Weather - Draw 0

Ventyx
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NOV 2023 thru OCT 2028

Cost and Flow Summary

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	807048	Injection Cost	950	Transportation Cost	18083	JAN 15, 2028	
Penalty Cost	0	Withdrawal Cost	1138	Other Variable Cost	598	System Served	432.083
Other Variable Cost	0	Carrying Cost	0			System Unserved	0.000
		Other Variable Cost	0			Total	432.083
Total Variable	807048	Total Variable	2087	Total Variable	18681		
Demand/Reservation Co	9.563e7	Demand Cost	15964	Demand Cost	594234		
Other Fixed Cost	0	Other Fixed Cost	25396	Other Fixed Cost	0		
Total Fixed	9.563e7	Total Fixed	41361	Total Fixed	594234		
Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0		
Net Supply Cost	9.644e7	Net Storage Cost	43448	Net Trans Cost	612915	Total Gas Cost	97102571
						Total Revenue	0
						Net Cost	97102571

Avg Cost of Served Demand 409.1 USD/DT
(System Cost/Served Dem.)

Avg Cost of Gas Purchased 399.1 USD/DT
(Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	237347.336	0.000	237347.336	0.000	237347.336	237347.336	0.000	0	432.083	0.000
Total	237347.336	0.000	237347.336	0.000	237347.336	237347.336	0.000	0	432.083	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	685.481	1825173.00	1824487.51			15.2280	10439	0	10439	15.2280
Centerville	18953.709	1825173.00	1806219.29			4.2065	79728	0	79728	4.2065
Dawn	56059.628	1825173.00	1769113.37			3.8727	217105	0	217105	3.8727
Dracut	2748.544	1825173.00	1822424.45			4.0570	11151	0	11151	4.0570
TGP Z4 313	32364.793	1825173.00	1792808.20			2.5441	82339	0	82339	2.5441
TGP Z4 200	14358.309	1825173.00	1810814.69			3.3401	47958	0	47958	3.3401
Hereford	4.025	1825173.00	1825168.97			3.3691	14	0	14	3.3691
LNG Inject	3390.099	1825173.00	1821782.90			5.4990	18642	0	18642	5.4990
LPG Inject	0.000	1825173.00	1825173.00			0.0000	0	0	0	0.0000

Scenario 2266
EGMA F&SP 2023 - Normal Weather - Draw 0

Ventyx
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Report 1z (Continued)

NOV 2023 thru OCT 2028

Cost and Flow Summary

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Millennium	11199.836	1825173.00	1813973.16			3.2876	36821	0	36821	3.2876
Niagara	15207.865	1825173.00	1809965.13			3.2183	48943	0	48943	3.2183
Ramapo	18815.599	1825173.00	1806357.40			2.8539	53698	0	53698	2.8539
Repsol 30	4935.000	4935.000	0.000			3.3368	16467	65146130	65162597	13204.1737
Repsol 40	2820.000	2820.000	0.000			3.3368	9410	30493030	30502440	10816.4680
TETCO M2	47508.745	1825173.00	1777664.25			2.8314	134514	0	134514	2.8314
TETCO M3	12560.786	1825173.00	1812612.21			3.1701	39819	0	39819	3.1701
Winter AGT	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Winter TGP	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Total	241612.417						807048	95639160	96446208	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	731.704	100	1047.815	1069.766	0.000	0.000	709.753	97	0.000	-21.951	4527	4022	-505
LNG Lawrence	11.628	100	128.842	129.191	0.000	0.000	11.279	97	0.000	-0.349	72	64	-8
LNG Marshfld	7.622	100	69.381	69.609	0.000	0.000	7.393	97	0.000	-0.229	47	42	-6
LNG Spring	948.413	100	2144.061	2172.513	0.000	0.000	919.961	97	0.000	-28.452	5868	5152	-715
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	173	173	0
LPG Meadow	70.749	100	0.000	0.000	0.000	0.000	70.749	100	0.000	0.000	942	942	0
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	289	289	0
DTI GSS TET	1441.753	100	7239.228	7134.983	0.000	104.245	1441.753	100	0.000	0.000	4259	3460	-799
Enbridge 16	1600.000	100	7590.049	7544.509	0.000	45.540	1600.000	100	45.267	0.000	7976	5565	-2411
Enbridge 18	1820.000	100	8874.577	8821.329	0.000	53.247	1820.000	100	52.928	0.000	9149	6335	-2815
Nat Fuel FSS	1100.000	100	5443.666	5419.170	0.000	24.496	1100.000	100	24.386	0.000	5454	3120	-2333
TETCO FSS-1	63.360	100	318.584	316.800	0.000	1.784	63.360	100	1.774	0.000	277	151	-126
TETCO SS-1	1588.950	100	7515.480	7473.393	0.000	42.087	1588.950	100	59.040	0.000	4838	3793	-1045
TGP FSMA	1222.594	100	6192.858	6112.970	0.000	79.888	1222.594	100	0.000	0.000	6133	2912	-3221
Total	10641.528	100	46564.541	46264.23	0.000	351.288	10590.547	100	183.395	-50.981	50004	36021	-13983

NOV 2023 thru OCT 2028 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	12601.795	226.832	12374.962	29232.000	16857.038	40	19693	0	19733	1.5659
TCPL 63398	9180.122	82.621	9097.501	47615.274	38517.773	29	15574	0	15603	1.6997
TCPL 64198	33890.380	610.027	33280.353	109303.929	76023.576	106	59661	0	59767	1.7636
Union 12292	33001.707	145.208	32856.500	108797.850	75941.350	105	10667	0	10772	0.3264
Union 12204	10259.143	45.140	10214.003	48145.104	37931.101	33	4720	0	4753	0.4633
GS 23-001	7290.060	25.515	7264.545	10884.000	3619.455	11	2216	0	2227	0.3055
PNG 233301 D	624.584	1.749	622.835	17042.100	16419.265	1	12963	0	12964	20.7563
PNG 233301 U	7310.530	20.469	7290.060	9084.000	1793.940	11	6969	0	6980	0.9548
PNG 208535 D	15474.416	0.000	15474.416	42934.500	27460.084	23	32783	0	32806	2.1200
PNG 208535 H	13288.741	0.000	13288.741	40194.000	26905.259	20	30690	0	30710	2.3110
PNG 208540	8961.070	0.000	8961.070	29232.000	20270.930	13	17520	0	17533	1.9566
IGT RTS	9097.501	0.000	9097.501	52690.680	43593.179	45	7821	0	7866	0.8646
N Fuel FST I	5488.674	45.007	5443.666	18270.000	12826.334	84	0	0	84	0.0154
N Fuel FST W	5394.784	44.237	5350.547	18270.000	12919.453	83	3011	0	3093	0.5734
MLP 217524	11199.836	77.279	11122.557	27405.000	16282.443	38	18132	0	18170	1.6223
TGP 95349	2058.108	16.671	2041.437	17857.098	15815.661	160	3572	0	3732	1.8133
TGP 5173	14358.309	162.249	14196.060	23290.596	9094.536	1474	13967	0	15440	1.0754
TGP 5293	23185.364	261.995	22923.369	22923.369	0.000	2379	5217	0	7597	0.3276
TGP 5196	14450.088	163.286	14286.802	28090.125	13803.323	1483	6393	0	7876	0.5450
TGP 5196 Wth	9099.542	0.000	9099.542	10048.500	948.958	14	0	0	14	0.0015
TGP 5291 Sup	11096.830	0.000	11096.830	11274.417	177.587	17	0	0	17	0.0015
TGP 5291 5-6	5573.358	45.144	5528.214	11274.417	5746.203	434	2255	0	2689	0.4825
TGP 5291 NF	5523.471	34.798	5488.674	11274.417	5785.743	348	0	0	348	0.0630
TGP Pool Law	21717.073	0.000	21717.073	68709.816	46992.743	0	0	0	0	0.0000
TGP Pool Spr	37258.810	0.000	37258.810	81162.648	43903.838	0	0	0	0	0.0000
TGP 39741	4111.035	33.299	4077.735	7455.987	3378.252	320	1491	0	1811	0.4406
TGP 41098	7039.393	57.019	6982.374	34225.191	27242.817	548	6846	0	7394	1.0503
TGP 98775 Up	4226.335	0.000	4226.335	11144.700	6918.365	0	0	0	0	0.0000
TGP 98775 Br	2282.410	5.250	2277.160	10962.000	8684.840	74	0	0	74	0.0324
TGP 98775 Sp	1943.925	4.471	1939.454	11144.700	9205.246	63	10036	0	10099	5.1952
TGP 330904 L	13288.741	30.564	13258.177	40194.000	26935.823	431	19042	0	19473	1.4654
TGP 330904 S	30603.000	70.387	30532.613	135928.800	105396.187	992	64398	0	65390	2.1367
TGP 48427	732.530	1.685	730.846	31059.000	30328.154	24	4128	0	4152	5.6682
TGP 362252	730.846	1.681	729.165	25578.000	24848.835	24	1827	0	1851	2.5322
TGP to AGT	2652.057	0.000	2652.057	10962.000	8309.943	0	0	0	0	0.0000
Unitil X Bro	2475.131	0.000	2475.131	10006.479	7531.348	0	0	0	0	0.0000
Unitil X Law	3771.402	0.000	3771.402	9315.873	5544.471	0	0	0	0	0.0000
Unitil X Spr	1018.011	0.000	1018.011	2524.914	1506.903	0	0	0	0	0.0000

NOV 2023 thru OCT 2028 | Cost and Flow Summary | Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT AIM	29938.156	880.265	29057.891	54810.000	25752.109	796	75215	0	76011	2.5389
AGT 93001EC	46428.912	199.084	46229.828	77440.014	31210.186	1812	26619	0	28432	0.6124
AGT 93401	3372.099	13.433	3358.665	10395.630	7036.965	132	2934	0	3065	0.9090
AGT 93001F	6982.374	23.740	6958.634	33781.230	26822.596	273	9533	0	9806	1.4043
AGT Hubline	685.481	2.331	683.151	36540.000	35856.849	27	8395	0	8422	12.2861
AGT 510352	19476.293	84.539	19391.754	87696.000	68304.246	760	24747	0	25507	1.3097
AGT 93201 Ce	284.312	1.138	283.174	2291.058	2007.884	11	647	0	658	2.3130
AGT 93201 La	2379.398	9.442	2369.956	7737.345	5367.389	93	2183	0	2276	0.9567
AGT 94501	6544.646	26.175	6518.472	26962.866	20444.394	256	7609	0	7864	1.2016
TET 800414	315.026	1.481	313.545	1929.312	1615.767	24	617	0	640	2.0331
TET 800462	32390.097	246.165	32143.932	66446.163	34302.231	3844	51432	0	55277	1.7066
TET 800382	2583.085	12.140	2570.944	7737.345	5166.401	193	2418	0	2611	1.0106
TET Stor Inj	7857.637	23.573	7834.064	1825173.00	1817338.93	384	0	0	384	0.0489
GSS Stor Inj	7261.011	21.783	7239.228	1825173.00	1817933.77	355	0	0	355	0.0489
GSS AMA Tran	3739.068	17.574	3721.495	11895.597	8174.102	279	0	0	279	0.0747
TRANSCO FT	812.830	5.934	806.896	2291.058	1484.162	16	293	0	309	0.3802
Total		3781.379				18681	594234		612915	1.0691

Natural Gas Supply VS. Requirements — Units: MDT

	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	OCT 2024	Total
Forecast Demand													
Demand	4742.689	6995.538	8505.809	7583.544	6849.600	3836.897	1843.365	1145.009	1043.522	1043.522	1173.909	2118.347	46881.750
Total Demand	4742.689	6995.538	8505.809	7583.544	6849.600	3836.897	1843.365	1145.009	1043.522	1043.522	1173.909	2118.347	46881.750
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	75.492	124.657	138.785	122.412	119.906	52.046	30.783	22.386	23.918	24.022	18.318	27.864	780.588
Injection	0.000	0.000	0.000	0.000	0.000	4.792	13.749	13.480	5.763	9.048	13.450	8.922	69.205
Withdrawal	0.012	5.020	13.651	12.098	4.976	0.000	0.000	0.000	0.000	0.000	0.000	0.000	35.757
Total Fuel	75.504	129.677	152.436	134.510	124.882	56.838	44.532	35.866	29.681	33.070	31.768	36.786	885.550
Storage Injections													
LNG Easton	12.514	0.000	0.000	0.000	0.000	0.000	105.016	15.330	15.841	0.000	31.171	15.841	195.712
LNG Lawrence	1.913	0.000	0.000	0.000	0.000	0.000	13.829	2.130	2.201	0.000	4.331	2.201	26.604
LNG Marshfld	0.835	0.000	0.000	0.000	0.000	0.000	8.645	0.990	1.023	0.000	2.013	1.023	14.529
LNG Spring	27.072	0.000	0.000	0.000	0.000	0.000	220.750	32.250	33.325	0.000	65.575	33.325	412.297
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	244.734	236.840	210.563	244.734	236.840	244.734	1418.446
Enbridge 16	0.000	0.000	0.000	0.000	0.000	357.840	369.768	357.840	0.000	0.000	352.952	0.000	1438.400
Enbridge 18	0.000	0.000	0.000	0.000	0.000	407.043	420.611	407.043	60.239	0.000	407.043	0.000	1701.980
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	34.194	147.736	181.634	187.689	187.689	181.634	135.394	1055.970
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.712	10.049	9.725	10.049	10.049	9.725	10.049	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.821	243.698	251.821	251.821	243.698	251.821	1494.679
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	249.421	241.376	0.000	241.000	241.376	249.421	1222.594
Total Inj	42.333	0.000	0.000	0.000	0.000	802.788	2042.381	1728.855	772.752	935.293	1776.357	943.811	9044.571
Total Req	4860.527	7125.215	8658.245	7718.054	6974.482	4696.523	3930.278	2909.730	1845.954	2011.885	2982.035	3098.943	56811.871
Sources of Supply													
Beverly	0.000	0.346	63.345	48.193	20.068	0.000	0.000	0.000	0.000	0.000	0.000	0.000	131.953
Centerville	77.718	259.958	653.549	536.100	459.496	16.201	0.000	0.000	0.000	0.000	0.000	128.795	2131.816
Dawn	1070.505	2560.128	1679.709	1406.566	1101.071	1382.863	795.150	769.500	60.603	0.000	764.582	0.000	11590.677
Dracut	0.000	0.000	20.096	8.571	7.242	0.000	6.019	0.000	0.000	0.000	0.000	36.131	78.059
TGP Z4 313	545.712	563.902	2.575	56.962	373.196	542.703	793.835	726.866	470.628	714.778	739.163	810.269	6340.589
TGP Z4 200	380.890	399.705	399.705	369.053	386.811	355.990	205.896	22.889	0.000	0.000	39.108	289.256	2849.303

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	OCT 2024	Total
Sources of Supply													
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Inject	42.333	0.000	0.000	0.000	0.000	0.000	348.240	50.700	52.390	0.000	103.090	52.390	649.143
LPG Inject	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Millennium	414.588	468.231	468.231	438.022	448.108	0.000	0.000	0.000	468.231	468.231	0.000	0.000	3173.641
Niagara	298.274	318.845	318.845	287.989	307.349	296.217	220.994	185.130	191.301	191.301	185.130	248.807	3050.183
Ramapo	374.770	16.319	84.005	48.956	460.339	903.748	817.043	599.257	71.991	71.991	0.000	0.000	3448.418
Repsol 30	0.000	130.659	354.355	440.114	61.873	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	92.547	216.255	192.409	62.789	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1088.309	1132.116	1136.073	1062.778	1130.370	3.744	513.195	496.640	478.420	513.195	1100.262	1480.905	10136.006
TETCO M3	522.517	5.776	40.435	30.525	707.335	1144.359	177.516	8.048	0.000	0.000	0.000	0.000	2636.512
Winter AGT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Winter TGP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	4815.616	5948.531	5437.177	4926.238	5526.049	4645.823	3877.888	2859.030	1793.564	1959.495	2931.335	3046.553	47767.300
Storage Withdrawals													
LNG Easton	12.514	12.931	35.887	12.096	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	195.712
LNG Lawrence	1.912	1.976	3.697	1.849	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	26.604
LNG Marshfld	0.835	0.863	4.099	0.807	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	14.529
LNG Spring	27.072	27.974	68.867	30.050	28.283	32.250	33.325	32.250	33.325	33.325	32.250	33.325	412.297
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	372.465	373.859	349.739	322.383	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1418.446
Enbridge 16	0.000	128.000	496.000	464.000	350.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1438.400
Enbridge 18	0.000	0.000	770.500	649.250	282.230	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1701.980
Nat Fuel FSS	2.577	210.293	310.000	281.700	251.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1055.970
TETCO FSS-1	0.000	12.672	25.344	21.825	3.519	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	409.510	571.487	509.938	3.743	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1494.679
TGP FSMA	0.000	0.000	561.328	470.560	190.706	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	44.910	1176.684	3221.067	2791.816	1448.433	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9044.571
Total Supply	4860.527	7125.215	8658.245	7718.054	6974.482	4696.523	3930.278	2909.730	1845.954	2011.885	2982.035	3098.943	56811.871
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	OCT 2024	Total
Net Storage Inv. Adj.													
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	731.704	731.704	718.773	682.886	670.790	657.859	642.529	731.704	731.704	731.704	715.863	731.704	731.704
LNG Lawrence	11.628	11.628	9.652	5.955	4.106	2.130	0.000	11.628	11.628	11.628	9.427	11.628	11.628
LNG Marshfld	7.622	7.622	6.759	2.660	1.853	0.990	0.000	7.622	7.622	7.622	6.599	7.622	7.622
LNG Spring	948.413	948.413	920.439	851.571	821.521	793.238	760.988	948.413	948.413	948.413	915.088	948.413	948.413
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1441.753	1069.288	695.429	345.690	23.307	23.307	268.042	504.881	715.445	960.179	1197.019	1441.753
Enbridge 16	1600.000	1600.000	1472.000	976.000	512.000	161.600	519.440	889.208	1247.048	1247.048	1247.048	1600.000	1600.000
Enbridge 18	1820.000	1820.000	1820.000	1049.500	400.250	118.020	525.063	945.675	1352.718	1412.957	1412.957	1820.000	1820.000
Nat Fuel FSS	1100.000	1097.423	887.130	577.130	295.430	44.030	78.224	225.960	407.594	595.283	782.971	964.606	1100.000
TETCO FSS-1	63.360	63.360	50.688	25.344	3.519	0.000	3.712	13.761	23.487	33.536	43.585	53.311	63.360
TETCO SS-1	1588.950	1588.950	1179.440	607.952	98.014	94.271	94.271	346.092	589.790	841.611	1093.432	1337.129	1588.950
TGP FSMA	1222.594	1222.594	1222.594	661.266	190.706	0.000	0.000	249.421	490.797	490.797	731.797	973.173	1222.594
Total Inv	10641.52	10638.95	9462.267	6241.199	3449.384	2000.950	2753.039	4743.030	6421.185	7141.547	8024.450	9750.107	10641.528
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	OCT 2025	Total
Forecast Demand													
Demand	4680.251	6897.698	8475.747	7552.686	6821.157	3782.239	1809.829	1116.869	1005.950	1005.950	1132.735	2110.158	46391.270
Total Demand	4680.251	6897.698	8475.747	7552.686	6821.157	3782.239	1809.829	1116.869	1005.950	1005.950	1132.735	2110.158	46391.270
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	75.352	123.512	135.724	123.259	120.642	58.487	30.458	21.881	22.465	19.088	17.757	20.596	769.223
Injection	0.000	0.000	0.000	0.000	0.000	7.771	13.792	13.480	6.749	5.899	13.480	8.908	70.078
Withdrawal	0.009	8.295	13.922	10.749	3.785	0.000	0.000	0.000	0.000	0.000	0.000	0.000	36.760
Total Fuel	75.361	131.807	149.646	134.009	124.428	66.258	44.250	35.361	29.214	24.987	31.237	29.504	876.061
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	125.843	15.330	15.841	0.000	25.061	0.000	182.075
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.128	13.829	2.130	2.201	0.000	4.331	1.852	24.471
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	8.645	0.990	1.023	0.000	2.013	0.794	13.465
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	256.450	32.250	33.325	0.000	65.575	4.873	392.473
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	201.266	244.734	236.840	0.000	244.734	236.840	244.734	1409.148
Enbridge 16	0.000	0.000	0.000	0.000	0.000	357.840	369.768	357.840	84.712	0.000	357.840	0.000	1528.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	407.043	420.611	407.043	132.315	0.000	407.043	0.000	1774.055
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	35.035	157.342	181.634	187.689	187.689	181.634	132.278	1063.300
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	9.725	10.049	9.725	4.036	10.049	9.725	10.049	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.821	243.698	251.821	251.821	243.698	251.821	1494.679
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	249.421	241.376	241.000	0.000	241.376	249.421	1222.594
Total Inj	0.000	0.000	0.000	0.000	0.000	1011.037	2108.515	1728.855	953.962	694.293	1775.135	895.823	9167.620
Total Req	4755.611	7029.504	8625.393	7686.695	6945.585	4859.534	3962.594	2881.085	1989.126	1725.230	2939.107	3035.485	56434.951
Sources of Supply													
Beverly	0.000	0.000	57.714	52.672	19.736	0.000	0.000	0.000	0.000	0.000	0.000	0.000	130.122
Centerville	65.173	228.640	643.940	582.259	451.626	14.027	167.826	0.000	0.000	0.000	0.000	1049.436	3202.926
Dawn	1061.151	1954.985	1500.591	1746.356	1317.934	1368.675	795.150	769.500	218.337	0.000	769.500	0.000	11502.178
Dracut	0.000	0.000	24.030	21.727	7.242	0.000	4.702	0.000	0.000	0.000	0.000	39.056	96.757
TGP Z4 313	545.712	563.902	0.000	50.315	364.227	542.682	793.487	725.592	714.119	563.902	738.733	810.282	6412.954
TGP Z4 200	380.820	399.705	386.811	361.024	386.811	355.771	203.839	18.723	0.000	0.000	39.207	291.023	2823.732

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	OCT 2025	Total
Sources of Supply													
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Inject	0.000	0.000	0.000	0.000	0.000	0.128	404.767	50.700	52.390	0.000	96.980	7.519	612.485
LPG Inject	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Millennium	453.127	468.231	468.231	422.918	468.231	0.000	0.000	0.000	468.231	0.000	0.000	0.000	2748.968
Niagara	298.274	318.845	308.560	279.806	296.591	295.946	226.895	185.130	191.301	191.301	185.130	249.893	3027.672
Ramapo	368.423	12.716	81.583	53.522	464.919	900.797	800.343	573.192	34.286	404.442	0.000	0.000	3694.223
Repsol 30	0.000	132.498	459.513	334.836	60.153	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	80.191	252.524	168.893	62.392	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1044.720	1128.616	1133.197	1021.840	1108.197	1059.516	513.195	507.548	258.072	513.195	1058.858	535.887	9882.842
TETCO M3	493.884	5.776	40.435	37.179	681.925	271.291	0.000	0.000	0.000	0.000	0.000	0.000	1530.492
Winter AGT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Winter TGP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	4711.284	5294.106	5357.129	5133.345	5689.984	4808.834	3910.204	2830.385	1936.736	1672.840	2888.407	2983.095	47216.350
Storage Withdrawals													
LNG Easton	12.514	12.931	41.192	15.105	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	204.026
LNG Lawrence	1.912	1.976	1.976	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	24.820
LNG Marshfld	0.835	0.863	3.291	0.780	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	13.694
LNG Spring	27.072	27.974	64.462	43.392	27.974	32.250	33.325	32.250	33.325	33.325	32.250	33.325	420.925
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	372.465	373.859	337.679	325.146	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1409.148
Enbridge 16	0.000	448.000	496.000	397.600	186.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1528.000
Enbridge 18	0.000	240.500	821.500	482.035	230.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1774.055
Nat Fuel FSS	1.994	233.006	310.000	270.870	247.430	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1063.300
TETCO FSS-1	0.000	11.616	24.288	23.233	4.223	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	386.068	567.794	521.854	18.963	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1494.679
TGP FSMA	0.000	0.000	563.902	459.017	199.675	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	44.328	1735.398	3268.264	2553.350	1255.601	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9218.601
Total Supply	4755.611	7029.504	8625.393	7686.695	6945.585	4859.534	3962.594	2881.085	1989.126	1725.230	2939.107	3035.485	56434.951
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	OCT 2025	Total
Net Storage Inv. Adj.													
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	731.704	719.190	706.260	665.068	649.962	637.032	621.702	731.704	731.704	731.704	715.863	725.594	731.704
LNG Lawrence	11.628	9.715	7.739	5.763	3.978	2.002	0.000	11.628	11.628	11.628	9.427	11.628	11.628
LNG Marshfld	7.622	6.787	5.924	2.633	1.853	0.990	0.000	7.622	7.622	7.622	6.599	7.622	7.622
LNG Spring	948.413	921.341	893.367	828.905	785.512	757.538	725.288	948.413	948.413	948.413	915.088	948.413	948.413
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1441.753	1069.288	695.429	357.750	32.605	233.871	478.605	715.445	715.445	960.179	1197.019	1441.753
Enbridge 16	1600.000	1600.000	1152.000	656.000	258.400	72.000	429.840	799.608	1157.448	1242.160	1242.160	1600.000	1600.000
Enbridge 18	1820.000	1820.000	1579.500	758.000	275.965	45.945	452.988	873.599	1280.642	1412.957	1412.957	1820.000	1820.000
Nat Fuel FSS	1100.000	1098.006	865.000	555.000	284.130	36.700	71.735	229.077	410.711	598.399	786.088	967.722	1100.000
TETCO FSS-1	63.360	63.360	51.744	27.456	4.223	0.000	9.725	19.775	29.500	33.536	43.585	53.311	63.360
TETCO SS-1	1588.950	1588.950	1202.882	635.089	113.234	94.271	94.271	346.092	589.790	841.611	1093.432	1337.129	1588.950
TGP FSMA	1222.594	1222.594	1222.594	658.692	199.675	0.000	0.000	249.421	490.797	731.797	731.797	973.173	1222.594
Total Inv	10641.52	10597.20	8861.802	5593.538	3040.187	1784.587	2744.923	4801.048	6479.203	7380.776	8022.679	9747.114	10641.528
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	Total
Forecast Demand													
Demand	4678.797	6897.492	8535.776	7613.079	6874.645	3854.712	1854.421	1143.335	1055.178	1055.178	1185.067	2164.520	46912.199
Total Demand	4678.797	6897.492	8535.776	7613.079	6874.645	3854.712	1854.421	1143.335	1055.178	1055.178	1185.067	2164.520	46912.199
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	73.457	123.356	132.550	123.206	111.229	39.375	18.994	22.299	20.101	20.134	13.893	21.473	720.067
Injection	0.000	0.000	0.000	0.000	0.000	4.638	13.866	13.480	10.244	5.899	13.480	9.158	70.764
Withdrawal	0.010	7.861	14.826	10.690	3.582	0.000	0.000	0.000	0.000	0.000	0.000	0.000	36.969
Total Fuel	73.468	131.217	147.376	133.896	114.811	44.013	32.860	35.779	30.344	26.033	27.373	30.631	827.800
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	146.022	15.330	15.841	0.000	25.061	0.000	202.254
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.477	13.829	2.130	2.201	0.000	4.331	1.852	24.820
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	8.645	0.990	1.023	0.000	2.013	0.794	13.465
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	300.492	32.250	33.325	0.000	65.575	4.873	436.515
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	244.734	236.840	233.871	244.734	236.840	244.734	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	357.840	369.768	357.840	84.581	0.000	357.840	0.000	1527.869
Enbridge 18	0.000	0.000	0.000	0.000	0.000	407.043	420.611	407.043	139.735	0.000	407.043	0.000	1781.475
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	173.616	181.634	187.689	187.689	181.634	187.689	1099.950
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.712	10.049	9.725	10.049	10.049	9.725	10.049	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.821	243.698	251.821	251.821	243.698	251.821	1494.679
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	249.421	241.376	241.000	0.000	241.376	249.421	1222.594
Total Inj	0.000	0.000	0.000	0.000	0.000	769.072	2189.009	1728.855	1201.135	694.293	1775.135	951.234	9308.733
Total Req	4752.265	7028.709	8683.152	7746.975	6989.456	4667.797	4076.289	2907.969	2286.657	1775.504	2987.574	3146.385	57048.733
Sources of Supply													
Beverly	0.000	0.000	59.805	53.749	20.068	0.000	0.000	0.000	0.000	0.000	0.000	0.000	133.622
Centerville	53.502	426.239	658.078	606.065	463.421	16.466	969.243	6.620	0.000	0.000	592.676	1082.899	4875.209
Dawn	1073.597	1887.937	1337.042	1751.177	1353.041	769.500	795.150	769.500	225.669	0.000	769.500	0.000	10732.113
Dracut	0.000	0.000	26.090	21.727	7.242	615.051	28.179	0.000	0.000	0.000	0.000	101.206	799.494
TGP Z4 313	545.712	384.340	0.000	140.189	453.915	543.256	799.332	739.139	808.052	563.902	749.713	812.031	6539.583
TGP Z4 200	381.374	399.705	386.811	361.024	381.785	357.100	210.784	18.101	0.000	0.000	46.235	296.978	2839.896

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	Total
Sources of Supply													
Hereford	0.000	0.000	0.000	0.000	0.000	0.211	0.000	0.000	0.000	0.000	0.000	0.000	0.211
LNG Inject	0.000	0.000	0.000	0.000	0.000	0.477	468.988	50.700	52.390	0.000	96.980	7.519	677.054
LPG Inject	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Millennium	0.000	468.231	468.231	422.918	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1359.380
Niagara	298.274	318.845	308.560	283.968	297.014	263.647	229.248	185.130	191.301	191.301	185.130	251.924	3004.342
Ramapo	913.761	10.861	86.805	55.755	970.874	903.435	0.000	591.439	454.716	454.716	0.000	0.000	4442.361
Repsol 30	0.000	45.534	501.311	366.675	73.479	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	65.263	285.470	157.239	56.028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	952.395	1127.891	1136.073	1026.131	0.000	3.744	522.975	496.640	502.139	513.195	496.640	541.439	7319.261
TETCO M3	445.694	5.776	40.435	42.699	1787.659	1144.211	0.000	0.000	0.000	0.000	0.000	0.000	3466.474
Winter AGT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Winter TGP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	4664.309	5140.623	5294.710	5289.315	5864.527	4617.097	4023.899	2857.269	2234.267	1723.114	2936.874	3093.995	47740.000
Storage Withdrawals													
LNG Easton	12.514	12.931	39.402	15.123	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	202.254
LNG Lawrence	1.912	1.976	1.976	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	24.820
LNG Marshfld	0.835	0.863	0.863	2.979	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	13.465
LNG Spring	27.072	27.974	72.937	49.001	29.481	32.250	33.325	32.250	33.325	33.325	32.250	33.325	436.515
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	43.293	373.859	373.859	337.679	313.063	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	0.000	449.137	494.863	397.600	186.269	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1527.869
Enbridge 18	0.000	267.000	821.500	462.955	230.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1781.475
Nat Fuel FSS	2.329	282.671	310.000	266.720	238.230	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1099.950
TETCO FSS-1	0.000	6.585	30.375	24.290	2.110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	285.527	678.765	530.387	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1494.679
TGP FSMA	0.000	179.562	563.902	369.142	109.987	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	87.956	1888.086	3388.442	2457.660	1124.929	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9308.733
Total Supply	4752.265	7028.709	8683.152	7746.975	6989.456	4667.797	4076.289	2907.969	2286.657	1775.504	2987.574	3146.385	57048.733
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	Total
Net Storage Inv. Adj.													
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	709.753	697.239	684.309	644.906	629.784	616.853	601.523	731.704	731.704	731.704	715.863	725.594	709.753
LNG Lawrence	11.279	9.367	7.390	5.414	3.629	1.653	0.000	11.628	11.628	11.628	9.427	11.628	11.279
LNG Marshfld	7.393	6.558	5.695	4.832	1.853	0.990	0.000	7.622	7.622	7.622	6.599	7.622	7.393
LNG Spring	919.961	892.889	864.914	791.978	742.977	713.496	681.246	948.413	948.413	948.413	915.088	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1398.460	1024.601	650.742	313.063	0.000	0.000	244.734	481.574	715.445	960.179	1197.019	1441.753
Enbridge 16	1600.000	1600.000	1150.863	656.000	258.400	72.131	429.971	799.739	1157.579	1242.160	1242.160	1600.000	1600.000
Enbridge 18	1820.000	1820.000	1553.000	731.500	268.545	38.525	445.568	866.179	1273.222	1412.957	1412.957	1820.000	1820.000
Nat Fuel FSS	1100.000	1097.671	815.000	505.000	238.280	0.050	0.050	173.666	355.300	542.989	730.677	912.311	1100.000
TETCO FSS-1	63.360	63.360	56.775	26.400	2.110	0.000	3.712	13.761	23.487	33.536	43.585	53.311	63.360
TETCO SS-1	1588.950	1588.950	1303.423	624.658	94.271	94.271	94.271	346.092	589.790	841.611	1093.432	1337.129	1588.950
TGP FSMA	1222.594	1222.594	1043.032	479.129	109.987	0.000	0.000	249.421	490.797	731.797	731.797	973.173	1222.594
Total Inv	10590.54	10502.59	8614.505	5226.063	2768.403	1643.474	2361.846	4498.465	6176.620	7325.365	7967.268	9691.703	10590.547
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	OCT 2027	Total
Forecast Demand													
Demand	4771.175	7041.287	8694.102	7772.834	7017.792	3991.145	1938.476	1196.500	1115.008	1115.008	1248.191	2210.065	48111.582
Total Demand	4771.175	7041.287	8694.102	7772.834	7017.792	3991.145	1938.476	1196.500	1115.008	1115.008	1248.191	2210.065	48111.582
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	77.133	125.041	136.205	125.639	112.636	40.084	19.666	23.218	21.930	17.564	19.243	32.416	750.775
Injection	0.000	0.000	0.000	0.000	0.000	4.638	13.492	10.326	10.584	9.158	13.480	9.158	70.836
Withdrawal	0.016	8.504	14.735	10.232	3.553	0.000	0.000	0.000	0.000	0.000	0.000	0.000	37.040
Total Fuel	77.149	133.545	150.940	135.871	116.189	44.722	33.158	33.543	32.513	26.723	32.723	41.575	858.651
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	25.310	155.000	15.330	0.902	0.000	40.000	0.000	236.542
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	2.130	13.829	2.130	0.000	0.000	6.532	1.852	26.473
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	8.645	0.990	0.000	0.000	3.036	0.794	13.465
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	310.000	32.250	12.900	0.000	86.000	4.873	446.023
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	233.871	236.840	244.734	244.734	236.840	244.734	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	357.840	369.768	357.840	81.832	0.000	357.840	0.000	1525.120
Enbridge 18	0.000	0.000	0.000	0.000	0.000	407.043	420.611	407.043	154.310	0.000	407.043	0.000	1796.050
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	173.616	181.634	187.689	187.689	181.634	187.689	1099.950
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.712	10.049	9.725	10.049	10.049	9.725	10.049	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.821	243.698	251.821	251.821	243.698	251.821	1494.679
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	232.954	0.000	249.421	249.421	241.376	249.421	1222.594
Total Inj	0.000	0.000	0.000	0.000	0.000	796.035	2180.164	1487.480	1193.658	943.715	1813.723	951.234	9366.009
Total Req	4848.324	7174.832	8845.042	7908.704	7133.981	4831.902	4151.798	2717.522	2341.180	2085.445	3094.638	3202.873	58336.242
Sources of Supply													
Beverly	0.000	0.000	63.545	58.066	20.068	0.000	0.000	0.000	0.000	0.000	0.000	0.000	141.679
Centerville	534.383	454.429	705.557	662.224	506.704	24.566	1013.192	6.578	0.000	0.000	0.000	0.000	3907.631
Dawn	1102.151	1887.612	1463.810	1841.045	1396.306	769.500	795.150	769.500	237.567	0.000	769.500	0.000	11032.140
Dracut	0.000	1.197	28.969	21.727	7.242	660.399	41.803	0.000	0.000	0.000	0.000	107.050	868.387
TGP Z4 313	545.712	275.198	0.233	195.286	507.728	543.966	788.474	511.485	762.471	816.583	762.423	814.148	6523.708
TGP Z4 200	382.130	399.705	399.705	361.024	387.658	358.896	223.251	23.056	0.000	0.000	55.954	303.825	2895.203

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	OCT 2027	Total
Sources of Supply													
Hereford	0.000	0.000	0.000	0.000	0.000	1.429	0.000	0.000	0.000	0.000	0.000	0.000	1.429
LNG Inject	0.000	0.000	0.000	0.000	0.000	27.440	487.474	50.700	13.802	0.000	135.568	7.519	722.503
LPG Inject	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Millennium	453.127	468.231	468.231	422.918	0.000	0.000	0.000	0.000	0.000	0.000	0.000	136.066	1948.572
Niagara	298.274	318.845	318.845	287.666	301.462	268.667	233.071	185.130	191.301	191.301	185.130	254.119	3033.811
Ramapo	375.911	16.319	103.326	64.313	970.874	906.279	14.855	623.732	570.454	0.000	0.000	24.392	3670.455
Repsol 30	0.000	82.410	471.566	344.162	88.862	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	42.300	251.877	215.213	54.610	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1052.952	1131.937	1136.073	1026.131	0.000	3.744	502.139	496.640	513.195	1025.171	1135.362	1503.364	9526.708
TETCO M3	14.470	5.776	41.318	49.830	1819.298	1216.315	0.000	0.000	0.000	0.000	0.000	0.000	3147.006
Winter AGT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Winter TGP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	4759.110	5083.958	5453.053	5549.602	6060.811	4781.202	4099.408	2666.822	2288.790	2033.055	3043.938	3150.483	48970.233
Storage Withdrawals													
LNG Easton	12.514	12.931	52.508	36.305	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	236.542
LNG Lawrence	1.912	1.976	1.976	3.438	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	26.473
LNG Marshfld	0.835	0.863	2.328	0.780	1.598	0.990	1.023	0.990	1.023	1.023	0.990	1.023	13.465
LNG Spring	27.072	27.974	78.478	46.790	35.658	32.250	33.325	32.250	33.325	33.325	32.250	33.325	446.023
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	43.293	373.859	373.859	337.679	313.063	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	0.000	448.000	496.000	397.600	183.520	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1525.120
Enbridge 18	0.000	315.014	799.986	451.030	230.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1796.050
Nat Fuel FSS	3.587	281.413	310.000	266.720	238.230	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1099.950
TETCO FSS-1	0.000	11.968	30.624	20.768	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	328.171	682.560	483.947	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1494.679
TGP FSMA	0.000	288.705	563.669	314.045	56.175	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	89.214	2090.875	3391.989	2359.102	1073.170	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9366.009
Total Supply	4848.324	7174.832	8845.042	7908.704	7133.981	4831.902	4151.798	2717.522	2341.180	2085.445	3094.638	3202.873	58336.242
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	OCT 2027	Total
Net Storage Inv. Adj.													
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	709.753	697.239	684.309	631.801	595.496	582.565	592.545	731.704	731.704	716.765	700.924	725.594	709.753
LNG Lawrence	11.279	9.367	7.390	5.414	1.976	0.000	0.000	11.628	11.628	9.427	7.226	11.628	11.279
LNG Marshfld	7.393	6.558	5.695	3.367	2.588	0.990	0.000	7.622	7.622	6.599	5.576	7.622	7.393
LNG Spring	919.961	892.889	864.914	786.436	739.646	703.988	671.738	948.413	948.413	927.988	894.663	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1398.460	1024.601	650.742	313.063	0.000	0.000	233.871	470.710	715.445	960.179	1197.019	1441.753
Enbridge 16	1600.000	1600.000	1152.000	656.000	258.400	74.880	432.720	802.488	1160.328	1242.160	1242.160	1600.000	1600.000
Enbridge 18	1820.000	1820.000	1504.986	705.000	253.970	23.950	430.993	851.604	1258.647	1412.957	1412.957	1820.000	1820.000
Nat Fuel FSS	1100.000	1096.413	815.000	505.000	238.280	0.050	0.050	173.666	355.300	542.989	730.677	912.311	1100.000
TETCO FSS-1	63.360	63.360	51.392	20.768	0.000	0.000	3.712	13.761	23.487	33.536	43.585	53.311	63.360
TETCO SS-1	1588.950	1588.950	1260.779	578.218	94.271	94.271	94.271	346.092	589.790	841.611	1093.432	1337.129	1588.950
TGP FSMA	1222.594	1222.594	933.889	370.220	56.175	0.000	0.000	232.954	232.954	482.376	731.797	973.173	1222.594
Total Inv	10590.54	10501.33	8410.459	5018.470	2659.368	1586.198	2331.533	4459.307	5896.087	7037.355	7928.680	9691.703	10590.547
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2027	DEC 2027	JAN 2028	FEB 2028	MAR 2028	APR 2028	MAY 2028	JUN 2028	JUL 2028	AUG 2028	SEP 2028	OCT 2028	Total
Forecast Demand													
Demand	4853.150	7169.698	8822.378	7902.491	7133.402	4091.370	2000.233	1234.413	1154.533	1154.533	1289.753	2244.580	49050.534
Total Demand	4853.150	7169.698	8822.378	7902.491	7133.402	4091.370	2000.233	1234.413	1154.533	1154.533	1289.753	2244.580	49050.534
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	68.172	126.280	138.230	127.800	115.251	48.533	19.566	23.411	22.609	18.186	19.773	32.917	760.726
Injection	0.000	0.000	0.000	0.000	0.000	8.241	11.674	8.279	10.413	9.158	13.480	9.158	70.404
Withdrawal	0.023	6.613	14.775	11.505	3.954	0.000	0.000	0.000	0.000	0.000	0.000	0.000	36.870
Total Fuel	68.195	132.893	153.005	139.305	119.204	56.774	31.241	31.690	33.022	27.344	33.253	42.075	868.000
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	20.000	155.000	15.330	15.841	0.000	25.061	0.000	231.232
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	2.130	13.829	2.130	2.201	0.000	4.331	1.852	26.473
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.990	8.645	0.990	1.023	0.000	2.013	0.794	14.455
LNG Spring	0.000	0.000	0.000	0.000	0.000	10.731	310.000	32.250	33.325	0.000	65.575	4.873	456.754
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	236.840	118.420	97.581	244.734	244.734	236.840	244.734	1423.883
Enbridge 16	0.000	0.000	0.000	0.000	0.000	357.840	369.768	357.840	81.832	0.000	357.840	0.000	1525.120
Enbridge 18	0.000	0.000	0.000	0.000	0.000	407.043	420.611	407.043	126.030	0.000	407.043	0.000	1767.770
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	24.153	149.513	181.634	187.689	187.689	181.634	187.689	1100.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	9.725	6.159	7.602	10.049	10.049	9.725	10.049	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.821	243.698	251.821	251.821	243.698	251.821	1494.679
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	232.954	0.000	249.421	249.421	241.376	249.421	1222.594
Total Inj	0.000	0.000	0.000	0.000	0.000	1069.452	2036.720	1346.097	1203.966	943.715	1775.135	951.234	9326.319
Total Req	4921.345	7302.591	8975.383	8041.796	7252.606	5217.596	4068.193	2612.201	2391.521	2125.592	3098.142	3237.888	59244.854
Sources of Supply													
Beverly	0.000	3.041	70.164	54.832	20.068	0.000	0.000	0.000	0.000	0.000	0.000	0.000	148.106
Centerville	82.731	714.393	740.184	610.137	1253.776	386.061	1041.549	7.296	0.000	0.000	0.000	0.000	4836.126
Dawn	1131.569	1984.454	1516.590	1819.763	1437.377	769.500	795.150	769.500	209.116	0.000	769.500	0.000	11202.520
Dracut	0.000	4.265	31.289	21.727	7.242	698.744	29.745	0.000	0.000	0.000	0.000	112.835	905.846
TGP Z4 313	545.712	2.575	75.405	354.753	563.902	544.501	792.838	523.340	779.026	779.026	771.520	815.361	6547.959
TGP Z4 200	382.744	399.705	399.705	373.917	399.705	360.280	232.373	28.683	0.000	0.000	63.801	309.262	2950.176

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2027	DEC 2027	JAN 2028	FEB 2028	MAR 2028	APR 2028	MAY 2028	JUN 2028	JUL 2028	AUG 2028	SEP 2028	OCT 2028	Total
Sources of Supply													
Hereford	0.000	0.000	0.000	0.000	0.000	2.385	0.000	0.000	0.000	0.000	0.000	0.000	2.385
LNG Inject	0.000	0.000	0.000	0.000	0.000	33.851	487.474	50.700	52.390	0.000	96.980	7.519	728.914
LPG Inject	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Millennium	0.000	468.231	468.231	438.022	451.367	0.000	0.000	0.000	0.000	0.000	0.000	143.423	1969.274
Niagara	298.274	318.845	318.845	298.274	316.169	296.217	236.105	185.130	191.301	191.301	185.130	256.266	3091.857
Ramapo	916.013	16.319	113.468	58.132	263.964	907.645	19.844	644.072	594.103	0.000	0.000	26.583	3560.142
Repsol 30	0.000	63.616	493.667	354.403	75.314	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	78.248	228.432	174.464	82.856	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	0.000	1134.035	1136.073	1062.778	1132.959	1153.750	380.725	352.780	513.195	1102.875	1160.511	1514.249	10643.928
TETCO M3	1511.849	6.374	43.970	32.830	171.316	13.963	0.000	0.000	0.000	0.000	0.000	0.000	1780.302
Winter AGT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Winter TGP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	4868.893	5194.099	5636.021	5654.033	6176.015	5166.896	4015.803	2561.501	2339.131	2073.202	3047.442	3185.498	49918.535
Storage Withdrawals													
LNG Easton	12.514	12.931	60.979	22.523	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	231.232
LNG Lawrence	1.912	1.976	3.565	1.849	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	26.473
LNG Marshfld	0.835	0.863	4.025	0.807	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	14.455
LNG Spring	27.072	27.974	83.792	45.648	42.218	32.250	33.325	32.250	33.325	33.325	32.250	33.325	456.754
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	5.076	373.859	373.859	349.739	321.350	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1423.883
Enbridge 16	0.000	448.000	496.000	406.400	174.720	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1525.120
Enbridge 18	0.000	256.541	805.459	489.455	216.315	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1767.770
Nat Fuel FSS	5.043	282.910	307.047	269.131	235.869	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1100.000
TETCO FSS-1	0.000	4.224	31.568	23.345	4.223	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	137.886	684.570	606.096	66.127	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1494.679
TGP FSMA	0.000	561.328	488.498	172.769	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	52.452	2108.492	3339.361	2387.763	1076.592	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9326.319
Total Supply	4921.345	7302.591	8975.383	8041.796	7252.606	5217.596	4068.193	2612.201	2391.521	2125.592	3098.142	3237.888	59244.854
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2027	DEC 2027	JAN 2028	FEB 2028	MAR 2028	APR 2028	MAY 2028	JUN 2028	JUL 2028	AUG 2028	SEP 2028	OCT 2028	Total
Net Storage Inv. Adj.													
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	709.753	697.239	684.309	623.329	600.806	587.875	592.545	731.704	731.704	731.704	715.863	725.594	709.753
LNG Lawrence	11.279	9.367	7.390	3.825	1.976	0.000	0.000	11.628	11.628	11.628	9.427	11.628	11.279
LNG Marshfld	7.393	6.558	5.695	1.670	0.863	0.000	0.000	7.622	7.622	7.622	6.599	7.622	7.393
LNG Spring	919.961	892.889	864.914	781.123	735.475	693.257	671.738	948.413	948.413	948.413	915.088	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1436.677	1062.818	688.959	339.220	17.870	254.710	373.130	470.710	715.445	960.179	1197.019	1441.753
Enbridge 16	1600.000	1600.000	1152.000	656.000	249.600	74.880	432.720	802.488	1160.328	1242.160	1242.160	1600.000	1600.000
Enbridge 18	1820.000	1820.000	1563.459	758.000	268.545	52.230	459.273	879.884	1286.927	1412.957	1412.957	1820.000	1820.000
Nat Fuel FSS	1100.000	1094.957	812.047	505.000	235.869	0.000	24.153	173.666	355.300	542.989	730.677	912.311	1100.000
TETCO FSS-1	63.360	63.360	59.136	27.568	4.223	0.000	9.725	15.885	23.487	33.536	43.585	53.311	63.360
TETCO SS-1	1588.950	1588.950	1451.064	766.494	160.399	94.271	94.271	346.092	589.790	841.611	1093.432	1337.129	1588.950
TGP FSMA	1222.594	1222.594	661.266	172.769	0.000	0.000	0.000	232.954	232.954	482.376	731.797	973.173	1222.594
Total Inv	10590.54	10538.09	8429.603	5090.242	2702.479	1625.888	2644.640	4628.970	5924.367	7075.944	7967.268	9691.703	10590.547
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	2023	2024	2025	2026	2027	Total
Forecast Demand						
Demand	46881.75	46391.27	46912.19	48111.58	49050.53	237347.33
Total Demand	46881.75	46391.27	46912.19	48111.58	49050.53	237347.33
Forecast Rt Mrktr Imbalance						
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed						
Transport	780.588	769.223	720.067	750.775	760.726	3781.379
Injection	69.205	70.078	70.764	70.836	70.404	351.288
Withdrawal	35.757	36.760	36.969	37.040	36.870	183.395
Total Fuel	885.550	876.061	827.800	858.651	868.000	4316.062
Storage Injections						
LNG Easton	195.712	182.075	202.254	236.542	231.232	1047.815
LNG Lawrence	26.604	24.471	24.820	26.473	26.473	128.842
LNG Marshfld	14.529	13.465	13.465	13.465	14.455	69.381
LNG Spring	412.297	392.473	436.515	446.023	456.754	2144.061
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	1418.446	1409.148	1441.753	1441.753	1423.883	7134.983
Enbridge 16	1438.400	1528.000	1527.869	1525.120	1525.120	7544.509
Enbridge 18	1701.980	1774.055	1781.475	1796.050	1767.770	8821.329
Nat Fuel FSS	1055.970	1063.300	1099.950	1099.950	1100.000	5419.170
TETCO FSS-1	63.360	63.360	63.360	63.360	63.360	316.800
TETCO SS-1	1494.679	1494.679	1494.679	1494.679	1494.679	7473.393
TGP FSMA	1222.594	1222.594	1222.594	1222.594	1222.594	6112.970
Total Inj	9044.571	9167.620	9308.733	9366.009	9326.319	46213.253
Total Req	56811.87	56434.95	57048.73	58336.24	59244.85	287876.65
Sources of Supply						
Beverly	131.953	130.122	133.622	141.679	148.106	685.481
Centerville	2131.816	3202.926	4875.209	3907.631	4836.126	18953.709
Dawn	11590.67	11502.17	10732.11	11032.14	11202.52	56059.628
Dracut	78.059	96.757	799.494	868.387	905.846	2748.544
TGP Z4 313	6340.589	6412.954	6539.583	6523.708	6547.959	32364.793
TGP Z4 200	2849.303	2823.732	2839.896	2895.203	2950.176	14358.309

Natural Gas Supply VS. Requirements

Units: MDT

	2023	2024	2025	2026	2027	Total
Sources of Supply						
Hereford	0.000	0.000	0.211	1.429	2.385	4.025
LNG Inject	649.143	612.485	677.054	722.503	728.914	3390.099
LPG Inject	0.000	0.000	0.000	0.000	0.000	0.000
Millennium	3173.641	2748.968	1359.380	1948.572	1969.274	11199.836
Niagara	3050.183	3027.672	3004.342	3033.811	3091.857	15207.865
Ramapo	3448.418	3694.223	4442.361	3670.455	3560.142	18815.599
Repsol 30	987.000	987.000	987.000	987.000	987.000	4935.000
Repsol 40	564.000	564.000	564.000	564.000	564.000	2820.000
TETCO M2	10136.00	9882.842	7319.261	9526.708	10643.92	47508.745
TETCO M3	2636.512	1530.492	3466.474	3147.006	1780.302	12560.786
Winter AGT	0.000	0.000	0.000	0.000	0.000	0.000
Winter TGP	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	47767.30	47216.35	47740.00	48970.23	49918.53	241612.41
Storage Withdrawals						
LNG Easton	195.712	204.026	202.254	236.542	231.232	1069.766
LNG Lawrence	26.604	24.820	24.820	26.473	26.473	129.191
LNG Marshfld	14.529	13.694	13.465	13.465	14.455	69.609
LNG Spring	412.297	420.925	436.515	446.023	456.754	2172.513
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	1418.446	1409.148	1441.753	1441.753	1423.883	7134.983
Enbridge 16	1438.400	1528.000	1527.869	1525.120	1525.120	7544.509
Enbridge 18	1701.980	1774.055	1781.475	1796.050	1767.770	8821.329
Nat Fuel FSS	1055.970	1063.300	1099.950	1099.950	1100.000	5419.170
TETCO FSS-1	63.360	63.360	63.360	63.360	63.360	316.800
TETCO SS-1	1494.679	1494.679	1494.679	1494.679	1494.679	7473.393
TGP FSMA	1222.594	1222.594	1222.594	1222.594	1222.594	6112.970
Total With	9044.571	9218.601	9308.733	9366.009	9326.319	46264.234
Total Supply	56811.87	56434.95	57048.73	58336.24	59244.85	287876.65

Net Storage Inv. Adj.						
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	2023	2024	2025	2026	2027	Total
Net Storage Inv. Adj.						
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000
Start of Year Inventory						
LNG Easton	731.704	731.704	709.753	709.753	709.753	731.704
LNG Lawrence	11.628	11.628	11.279	11.279	11.279	11.628
LNG Marshfld	7.622	7.622	7.393	7.393	7.393	7.622
LNG Spring	948.413	948.413	919.961	919.961	919.961	948.413
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1441.753	1441.753	1441.753	1441.753	1441.753
Enbridge 16	1600.000	1600.000	1600.000	1600.000	1600.000	1600.000
Enbridge 18	1820.000	1820.000	1820.000	1820.000	1820.000	1820.000
Nat Fuel FSS	1100.000	1100.000	1100.000	1100.000	1100.000	1100.000
TETCO FSS-1	63.360	63.360	63.360	63.360	63.360	63.360
TETCO SS-1	1588.950	1588.950	1588.950	1588.950	1588.950	1588.950
TGP FSMA	1222.594	1222.594	1222.594	1222.594	1222.594	1222.594
Total Inv	10641.52	10641.52	10590.54	10590.54	10590.54	10641.528
Unsupplied Demand						
Demand	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000

NOV 2023 thru OCT 2024 — Cost and Flow Summary — Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	163058	Injection Cost	186	Transportation Cost	3838	JAN 15, 2024	
Penalty Cost	0	Withdrawal Cost	223	Other Variable Cost	130	System Served	521.141
Other Variable Cost	0	Carrying Cost	0			System Unserved	0.000
		Other Variable Cost	0			Total	521.141
Total Variable	163058	Total Variable	409	Total Variable	3968		
Demand/Reservation Co	1.912e7	Demand Cost	3193	Demand Cost	118847		
Other Fixed Cost	0	Other Fixed Cost	4758	Other Fixed Cost	0		
Total Fixed	1.912e7	Total Fixed	7951	Total Fixed	118847		
Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0		
Net Supply Cost	1.929e7	Net Storage Cost	8360	Net Trans Cost	122814	Total Gas Cost	19422063
						Total Revenue	0
						Net Cost	19422063

Avg Cost of Served Demand 375.4 USD/DT
(System Cost/Served Dem.)

Avg Cost of Gas Purchased 366.2 USD/DT
(Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	51730.851	0.000	51730.851	0.000	51730.851	51730.851	0.000	0	521.141	0.000
Total	51730.851	0.000	51730.851	0.000	51730.851	51730.851	0.000	0	521.141	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	345.947	365634.000	365288.053			15.1864	5254	0	5254	15.1864
Centerville	4153.777	365634.000	361480.223			4.9893	20725	0	20725	4.9893
Dawn	12731.185	365634.000	352902.815			3.2063	40820	0	40820	3.2063
Dracut	391.207	365634.000	365242.793			8.9407	3498	0	3498	8.9407
TGP Z4 313	6340.589	365634.000	359293.411			2.2497	14265	0	14265	2.2497
TGP Z4 200	2855.814	365634.000	362778.186			2.7463	7843	0	7843	2.7463
Hereford	0.000	365634.000	365634.000			0.0000	0	0	0	0.0000
LNG Inject	1107.699	365634.000	364526.301			5.1586	5714	0	5714	5.1586
LPG Inject	21.000	365634.000	365613.000			17.0000	357	0	357	17.0000

Scenario 2267
EGMA F&SP 2023 - Design Weather - Draw 0

Ventyx
SENDOUT® Version 14.3.0
Report 1 (Continued)

NOV 2023 thru OCT 2024

Cost and Flow Summary

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Millennium	3188.328	365634.000	362445.672			2.6149	8337	0	8337	2.6149
Niagara	3016.853	365634.000	362617.147			2.7218	8211	0	8211	2.7218
Ramapo	3788.827	365634.000	361845.173			2.8749	10892	0	10892	2.8749
Repsol 30	987.000	987.000	0.000			2.3530	2322	13029226	13031548	13203.1899
Repsol 40	564.000	564.000	0.000			2.3530	1327	6098606	6099933	10815.4842
TETCO M2	10143.252	365634.000	355490.748			2.4041	24386	0	24386	2.4041
TETCO M3	3020.491	365634.000	362613.509			2.9442	8893	0	8893	2.9442
Winter AGT	10.685	2275.000	2264.315			20.0000	214	0	214	20.0000
Winter TGP	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Total	52666.653						163058	19127832	19290890	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	731.704	100	420.207	420.207	0.000	0.000	731.704	100	0.000	0.000	4527	4145	-382
LNG Lawrence	11.628	100	33.829	33.829	0.000	0.000	11.628	100	0.000	0.000	72	61	-10
LNG Marshfld	7.622	100	19.266	19.266	0.000	0.000	7.622	100	0.000	0.000	47	42	-5
LNG Spring	948.413	100	634.396	634.396	0.000	0.000	948.413	100	0.000	0.000	5868	5333	-535
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	173	173	0
LPG Meadow	70.749	100	21.000	21.000	0.000	0.000	70.749	100	0.000	0.000	942	1019	77
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	289	289	0
DTI GSS TET	1441.753	100	1439.170	1418.446	0.000	20.724	1441.753	100	0.000	0.000	4259	3222	-1037
Enbridge 16	1600.000	100	1438.229	1429.600	0.000	8.629	1600.000	100	8.578	0.000	7976	5074	-2902
Enbridge 18	1820.000	100	1715.592	1705.299	0.000	10.294	1820.000	100	10.232	0.000	9149	5625	-3524
Nat Fuel FSS	1100.000	100	1016.565	1011.990	0.000	4.575	1100.000	100	4.554	0.000	5454	3107	-2347
TETCO FSS-1	63.360	100	63.717	63.360	0.000	0.357	63.360	100	0.355	0.000	277	141	-136
TETCO SS-1	1588.950	100	1503.096	1494.679	0.000	8.417	1588.950	100	11.808	0.000	4838	3582	-1256
TGP FSMA	1222.594	100	1238.572	1222.594	0.000	15.978	1222.594	100	0.000	0.000	6133	2680	-3452
Total	10641.528	100	9543.639	9474.666	0.000	68.973	10641.528	100	35.526	0.000	50004	34494	-15510

NOV 2023 thru OCT 2024 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2750.822	49.515	2701.307	5856.000	3154.693	9	3939	0	3947	1.4350
TCPL 63398	2322.628	20.904	2301.725	9538.692	7236.967	7	3115	0	3122	1.3443
TCPL 64198	7576.255	136.373	7439.882	21896.682	14456.800	24	11932	0	11956	1.5781
Union 12292	7078.437	31.145	7047.292	21795.300	14748.008	23	2133	0	2156	0.3046
Union 12204	2864.194	12.602	2851.591	9644.832	6793.241	9	944	0	953	0.3328
GS 23-001	1502.332	5.258	1497.074	2184.000	686.926	2	443	0	445	0.2965
PNG 233301 D	182.848	0.512	182.336	3409.800	3227.464	0	2593	0	2593	14.1806
PNG 233301 U	1506.550	4.218	1502.332	1824.000	321.668	2	1394	0	1396	0.9267
PNG 208535 D	3562.683	0.000	3562.683	8601.000	5038.317	5	6557	0	6562	1.8418
PNG 208535 H	2770.638	0.000	2770.638	8052.000	5281.362	4	6138	0	6142	2.2169
PNG 208540	2118.471	0.000	2118.471	5856.000	3737.529	3	3504	0	3507	1.6555
IGT RTS	2301.725	0.000	2301.725	10555.440	8253.715	11	1564	0	1576	0.6845
N Fuel FST I	1024.969	8.405	1016.565	3660.000	2643.435	16	0	0	16	0.0154
N Fuel FST W	1007.436	8.261	999.175	3660.000	2660.825	15	602	0	618	0.6130
MLP 217524	3188.328	21.999	3166.329	5490.000	2323.671	11	3626	0	3637	1.1408
TGP 95349	783.463	6.346	777.117	3577.284	2800.167	61	714	0	775	0.9896
TGP 5173	2855.814	32.271	2823.543	4665.768	1842.225	293	2793	0	3086	1.0808
TGP 5293	4644.687	52.485	4592.202	4592.202	0.000	477	1043	0	1520	0.3273
TGP 5196	2679.100	30.274	2648.826	5627.250	2978.424	275	1279	0	1554	0.5799
TGP 5196 Wth	1679.925	0.000	1679.925	2013.000	333.075	3	0	0	3	0.0015
TGP 5291 Sup	2194.437	0.000	2194.437	2258.586	64.149	3	0	0	3	0.0015
TGP 5291 5-6	1162.970	9.420	1153.550	2258.586	1105.036	91	451	0	542	0.4657
TGP 5291 NF	1031.468	6.498	1024.969	2258.586	1233.617	65	0	0	65	0.0630
TGP Pool Law	4790.667	0.000	4790.667	13764.528	8973.861	0	0	0	0	0.0000
TGP Pool Spr	7204.571	0.000	7204.571	16259.184	9054.613	0	0	0	0	0.0000
TGP 39741	822.415	6.662	815.754	1493.646	677.892	64	298	0	362	0.4405
TGP 41098	1518.262	12.298	1505.964	6856.278	5350.314	118	1369	0	1487	0.9796
TGP 98775 Up	996.787	0.000	996.787	2232.600	1235.813	0	0	0	0	0.0000
TGP 98775 Br	369.243	0.849	368.394	2196.000	1827.606	12	0	0	12	0.0324
TGP 98775 Sp	627.544	1.443	626.101	2232.600	1606.499	20	2007	0	2028	3.2309
TGP 330904 L	2770.638	6.372	2764.265	8052.000	5287.735	90	3808	0	3898	1.4070
TGP 330904 S	6547.811	15.060	6532.751	27230.400	20697.649	212	12880	0	13092	1.9994
TGP 48427	261.099	0.601	260.499	6222.000	5961.501	8	826	0	834	3.1947
TGP 362252	260.499	0.599	259.900	5124.000	4864.100	8	365	0	374	1.4351
Unitil X Bro	527.165	0.000	527.165	2004.582	1477.417	0	0	0	0	0.0000
Unitil X Law	762.609	0.000	762.609	1866.234	1103.625	0	0	0	0	0.0000
Unitil X Spr	207.300	0.000	207.300	505.812	298.512	0	0	0	0	0.0000
AGT AIM	6955.156	203.170	6751.986	10980.000	4228.014	185	15043	0	15228	2.1895

NOV 2023 thru OCT 2024 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001EC	9910.079	43.281	9866.798	15518.982	5652.184	387	5324	0	5711	0.5762
AGT 93401	783.475	3.195	780.281	2082.540	1302.259	31	587	0	617	0.7879
AGT 93001F	1505.964	5.120	1500.844	6767.340	5266.496	59	1907	0	1965	1.3051
AGT Hubline	345.947	1.176	344.771	7320.000	6975.229	14	1679	0	1693	4.8925
AGT 510352	4232.302	15.205	4217.097	17568.000	13350.903	165	4949	0	5115	1.2085
AGT 93201 Ce	74.463	0.253	74.210	458.964	384.754	3	129	0	132	1.7755
AGT 93201 La	538.355	2.161	536.194	1550.010	1013.816	21	437	0	458	0.8502
AGT 94501	1666.601	6.789	1659.813	5401.428	3741.615	65	1522	0	1587	0.9521
TET 800414	63.005	0.296	62.709	386.496	323.787	5	123	0	128	2.0331
TET 800462	7128.224	54.175	7074.049	13311.054	6237.005	846	10286	0	11132	1.5617
TET 800382	519.110	2.440	516.670	1550.010	1033.340	39	484	0	522	1.0062
TET Stor Inj	1571.527	4.715	1566.813	365634.000	364067.187	77	0	0	77	0.0489
GSS Stor Inj	1443.500	4.331	1439.170	365634.000	364194.830	71	0	0	71	0.0489
GSS AMA Tran	745.223	3.503	741.720	2383.026	1641.306	56	0	0	56	0.0747
TRANSCO FT	154.113	1.125	152.988	458.964	305.976	3	59	0	62	0.4000
Total		831.303				3968	118847		122814	0.9897

NOV 2024 thru OCT 2025 Cost and Flow Summary Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	186722	Injection Cost	186	Transportation Cost	3789	JAN 15, 2025	
Penalty Cost	0	Withdrawal Cost	224	Other Variable Cost	128	System Served	520.356
Other Variable Cost	0	Carrying Cost	0			System Unserved	0.000
		Other Variable Cost	0			Total	520.356
Total Variable	186722	Total Variable	411	Total Variable	3917		
Demand/Reservation Co	1.912e7	Demand Cost	3193	Demand Cost	118847		
Other Fixed Cost	0	Other Fixed Cost	5160	Other Fixed Cost	0		
Total Fixed	1.912e7	Total Fixed	8353	Total Fixed	118847		
Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0		
Net Supply Cost	1.931e7	Net Storage Cost	8763	Net Trans Cost	122764	Total Gas Cost	19446081
						Total Revenue	0
						Net Cost	19446081

Avg Cost of Served Demand 379.5 USD/DT Avg Cost of Gas Purchased 370.6 USD/DT
(System Cost/Served Dem.) (Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	51236.906	0.000	51236.906	0.000	51236.906	51236.906	0.000	0	520.356	0.000
Total	51236.906	0.000	51236.906	0.000	51236.906	51236.906	0.000	0	520.356	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	333.458	364635.000	364301.542			15.4403	5149	0	5149	15.4403
Centerville	5200.808	364635.000	359434.192			4.5218	23517	0	23517	4.5218
Dawn	12590.046	364635.000	352044.954			3.7625	47370	0	47370	3.7625
Dracut	439.453	364635.000	364195.547			8.6684	3809	0	3809	8.6684
TGP Z4 313	6319.021	364635.000	358315.979			2.6565	16787	0	16787	2.6565
TGP Z4 200	2840.481	364635.000	361794.519			3.3968	9648	0	9648	3.3968
Hereford	0.000	364635.000	364635.000			0.0000	0	0	0	0.0000
LNG Inject	1083.588	364635.000	363551.412			5.5992	6067	0	6067	5.5992
LPG Inject	21.000	364635.000	364614.000			17.0000	357	0	357	17.0000

Scenario 2267
EGMA F&SP 2023 - Design Weather - Draw 0

Ventyx
SENDOUT® Version 14.3.0
Report 1 (Continued)

NOV 2024 thru OCT 2025

Cost and Flow Summary

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Millennium	2748.968	364635.000	361886.032			3.2379	8901	0	8901	3.2379
Niagara	3006.292	364635.000	361628.708			3.3044	9934	0	9934	3.3044
Ramapo	4159.021	364635.000	360475.979			3.1958	13292	0	13292	3.1958
Repsol 30	987.000	987.000	0.000			3.2614	3219	13029226	13032445	13204.0983
Repsol 40	564.000	564.000	0.000			3.2614	1839	6098606	6100445	10816.3926
TETCO M2	9918.236	364635.000	354716.764			2.9864	29619	0	29619	2.9864
TETCO M3	1891.810	364635.000	362743.190			3.7017	7003	0	7003	3.7017
Winter AGT	10.545	2250.000	2239.455			20.0000	211	0	211	20.0000
Winter TGP	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Total	52113.728						186722	19127832	19314554	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	731.704	100	413.943	435.894	0.000	0.000	709.753	97	0.000	-21.951	4145	3994	-151
LNG Lawrence	11.628	100	33.121	33.121	0.000	0.000	11.628	100	0.000	0.000	61	67	5
LNG Marshfld	7.622	100	19.238	19.238	0.000	0.000	7.622	100	0.000	0.000	42	47	5
LNG Spring	948.413	100	617.286	645.738	0.000	0.000	919.961	97	0.000	-28.452	5333	5160	-173
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	173	173	0
LPG Meadow	70.749	100	21.000	21.000	0.000	0.000	70.749	100	0.000	0.000	1019	1074	54
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	289	289	0
DTI GSS TET	1441.753	100	1429.736	1409.148	0.000	20.588	1441.753	100	0.000	0.000	3222	3625	402
Enbridge 16	1600.000	100	1537.223	1528.000	0.000	9.223	1600.000	100	9.168	0.000	5074	5421	346
Enbridge 18	1820.000	100	1791.962	1781.210	0.000	10.752	1820.000	100	10.687	0.000	5625	6177	552
Nat Fuel FSS	1100.000	100	1023.928	1019.320	0.000	4.608	1100.000	100	4.587	0.000	3107	3324	217
TETCO FSS-1	63.360	100	63.717	63.360	0.000	0.357	63.360	100	0.355	0.000	141	159	19
TETCO SS-1	1588.950	100	1503.096	1494.679	0.000	8.417	1588.950	100	11.808	0.000	3582	3955	373
TGP FSMA	1222.594	100	1238.572	1222.594	0.000	15.978	1222.594	100	0.000	0.000	2680	3058	377
Total	10641.528	100	9692.821	9673.302	0.000	69.923	10591.124	100	36.605	-50.404	34494	36521	2027

NOV 2024 thru OCT 2025 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2734.105	49.214	2684.892	5840.000	3155.108	9	3939	0	3947	1.4437
TCPL 63398	2297.763	20.680	2277.083	9512.630	7235.547	7	3115	0	3122	1.3588
TCPL 64198	7475.157	134.553	7340.604	21836.855	14496.251	23	11932	0	11956	1.5994
Union 12292	6993.928	30.773	6963.155	21735.750	14772.595	22	2133	0	2156	0.3082
Union 12204	2822.183	12.418	2809.765	9618.480	6808.715	9	944	0	953	0.3377
GS 23-001	1483.990	5.194	1478.796	2172.000	693.204	2	443	0	445	0.3002
PNG 233301 D	177.613	0.497	177.116	3407.500	3230.384	0	2593	0	2593	14.5985
PNG 233301 U	1488.157	4.167	1483.990	1812.000	328.010	2	1394	0	1396	0.9381
PNG 208535 D	3466.857	0.000	3466.857	8577.500	5110.643	5	6557	0	6562	1.8927
PNG 208535 H	2811.058	0.000	2811.058	8030.000	5218.942	4	6138	0	6142	2.1850
PNG 208540	2081.811	0.000	2081.811	5840.000	3758.189	3	3504	0	3507	1.6846
IGT RTS	2277.083	0.000	2277.083	10526.600	8249.517	11	1564	0	1575	0.6918
N Fuel FST I	1032.393	8.466	1023.928	3650.000	2626.072	16	0	0	16	0.0154
N Fuel FST W	1014.733	8.321	1006.412	3650.000	2643.588	16	602	0	618	0.6087
MLP 217524	2748.968	18.968	2730.000	5475.000	2745.000	9	3626	0	3636	1.3226
TGP 95349	782.662	6.340	776.322	3567.510	2791.188	61	714	0	775	0.9906
TGP 5173	2840.481	32.097	2808.384	4653.020	1844.636	292	2793	0	3085	1.0860
TGP 5293	4631.997	52.342	4579.655	4579.655	0.000	475	1043	0	1519	0.3279
TGP 5196	2677.460	30.255	2647.204	5611.875	2964.671	275	1279	0	1553	0.5802
TGP 5196 Wth	1671.047	0.000	1671.047	2007.500	336.453	3	0	0	3	0.0015
TGP 5291 Sup	2188.805	0.000	2188.805	2252.415	63.610	3	0	0	3	0.0015
TGP 5291 5-6	1149.866	9.314	1140.552	2252.415	1111.863	90	451	0	541	0.4701
TGP 5291 NF	1038.939	6.545	1032.393	2252.415	1220.022	65	0	0	65	0.0630
TGP Pool Law	4604.363	0.000	4604.363	13726.920	9122.557	0	0	0	0	0.0000
TGP Pool Spr	7347.755	0.000	7347.755	16214.760	8867.005	0	0	0	0	0.0000
TGP 39741	817.487	6.622	810.865	1489.565	678.700	64	298	0	362	0.4427
TGP 41098	1494.421	12.105	1482.316	6837.545	5355.229	116	1369	0	1485	0.9940
TGP 98775 Up	971.876	0.000	971.876	2226.500	1254.624	0	0	0	0	0.0000
TGP 98775 Br	365.984	0.842	365.142	2190.000	1824.858	12	0	0	12	0.0324
TGP 98775 Sp	605.892	1.394	604.499	2226.500	1622.001	20	2007	0	2027	3.3452
TGP 330904 L	2811.058	6.465	2804.593	8030.000	5225.407	91	3808	0	3900	1.3872
TGP 330904 S	6445.990	14.826	6431.164	27156.000	20724.836	209	12880	0	13089	2.0305
TGP 48427	298.370	0.686	297.684	6205.000	5907.316	10	826	0	835	2.7997
TGP 362252	297.684	0.685	297.000	5110.000	4813.000	10	365	0	375	1.2598
Unitil X Bro	515.880	0.000	515.880	1999.105	1483.225	0	0	0	0	0.0000
Unitil X Law	755.616	0.000	755.616	1861.135	1105.519	0	0	0	0	0.0000
Unitil X Spr	207.300	0.000	207.300	504.430	297.130	0	0	0	0	0.0000
AGT AIM	6889.021	202.490	6686.532	10950.000	4263.468	183	15043	0	15226	2.2102

NOV 2024 thru OCT 2025 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001EC	8711.282	36.402	8674.881	15467.350	6792.469	340	5324	0	5664	0.6502
AGT 93401	755.367	3.053	752.313	2076.850	1324.537	29	587	0	616	0.8158
AGT 93001F	1482.316	5.040	1477.276	6748.850	5271.574	58	1907	0	1964	1.3253
AGT Hubline	333.458	1.134	332.324	7300.000	6967.676	13	1679	0	1692	5.0742
AGT 510352	5264.387	21.346	5243.041	17520.000	12276.959	206	4949	0	5155	0.9792
AGT 93201 Ce	88.155	0.330	87.825	457.710	369.885	3	129	0	133	1.5058
AGT 93201 La	514.439	2.039	512.399	1545.775	1033.376	20	437	0	457	0.8879
AGT 94501	1566.830	6.228	1560.602	5386.670	3826.068	61	1522	0	1583	1.0103
TET 800414	63.005	0.296	62.709	385.440	322.731	5	123	0	128	2.0331
TET 800462	6912.670	52.536	6860.134	13274.685	6414.551	820	10286	0	11107	1.6067
TET 800382	505.871	2.378	503.494	1545.775	1042.281	38	484	0	521	1.0305
TET Stor Inj	1571.527	4.715	1566.813	364635.000	363068.187	77	0	0	77	0.0489
GSS Stor Inj	1434.038	4.302	1429.736	364635.000	363205.264	70	0	0	70	0.0489
GSS AMA Tran	750.427	3.527	746.900	2376.515	1629.615	56	0	0	56	0.0747
TRANSCO FT	152.850	1.116	151.734	457.710	305.976	3	59	0	62	0.4031
Total		820.698				3917	118847		122764	1.0028

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	197148	Injection Cost	190	Transportation Cost	3520	JAN 15, 2026	
Penalty Cost	0	Withdrawal Cost	228	Other Variable Cost	122	System Served	522.660
Other Variable Cost	0	Carrying Cost	0			System Unserved	0.000
		Other Variable Cost	0			Total	522.660
Total Variable	197148	Total Variable	418	Total Variable	3642		
Demand/Reservation Co	1.912e7	Demand Cost	3193	Demand Cost	118847		
Other Fixed Cost	0	Other Fixed Cost	5160	Other Fixed Cost	0		
Total Fixed	1.912e7	Total Fixed	8353	Total Fixed	118847		
Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0		
Net Supply Cost	1.932e7	Net Storage Cost	8771	Net Trans Cost	122489	Total Gas Cost	19456239
						Total Revenue	0
						Net Cost	19456239

Avg Cost of Served Demand 375.9 USD/DT
(System Cost/Served Dem.)

Avg Cost of Gas Purchased 367.1 USD/DT
(Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	51749.575	0.000	51749.575	0.000	51749.575	51749.575	0.000	0	522.660	0.000
Total	51749.575	0.000	51749.575	0.000	51749.575	51749.575	0.000	0	522.660	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	344.167	364635.000	364290.833			15.7284	5413	0	5413	15.7284
Centerville	6662.648	364635.000	357972.352			4.1762	27825	0	27825	4.1762
Dawn	11960.997	364635.000	352674.003			4.1445	49573	0	49573	4.1445
Dracut	1261.189	364635.000	363373.811			5.0451	6363	0	6363	5.0451
TGP Z4 313	6387.336	364635.000	358247.664			2.6387	16854	0	16854	2.6387
TGP Z4 200	2862.340	364635.000	361772.660			3.5728	10226	0	10226	3.5728
Hereford	0.211	364635.000	364634.789			3.4240	1	0	1	3.4240
LNG Inject	1160.251	364635.000	363474.749			5.5901	6486	0	6486	5.5901
LPG Inject	21.000	364635.000	364614.000			17.0000	357	0	357	17.0000

Scenario 2267
EGMA F&SP 2023 - Design Weather - Draw 0

Ventyx
SENDOUT® Version 14.3.0
Report 1 (Continued)

NOV 2025 thru OCT 2026

Cost and Flow Summary

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Millennium	1359.380	364635.000	363275.620			3.9607	5384	0	5384	3.9607
Niagara	3022.796	364635.000	361612.204			3.4202	10339	0	10339	3.4202
Ramapo	4879.654	364635.000	359755.346			3.2553	15885	0	15885	3.2553
Repsol 30	987.000	987.000	0.000			3.7089	3661	13029226	13032887	13204.5457
Repsol 40	564.000	564.000	0.000			3.7089	2092	6098606	6100698	10816.8401
TETCO M2	7356.120	364635.000	357278.880			3.1617	23258	0	23258	3.1617
TETCO M3	3789.611	364635.000	360845.389			3.4838	13202	0	13202	3.4838
Winter AGT	11.503	2250.000	2238.497			20.0000	230	0	230	20.0000
Winter TGP	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Total	52630.203						197148	19127832	19324980	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	709.753	97	443.816	443.816	0.000	0.000	709.753	97	0.000	0.000	3994	3977	-17
LNG Lawrence	11.628	100	34.467	34.467	0.000	0.000	11.628	100	0.000	0.000	67	66	-0
LNG Marshfld	7.622	100	19.238	19.238	0.000	0.000	7.622	100	0.000	0.000	47	46	-0
LNG Spring	919.961	97	662.731	662.731	0.000	0.000	919.961	97	0.000	0.000	5160	5145	-15
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	173	173	0
LPG Meadow	70.749	100	21.000	21.000	0.000	0.000	70.749	100	0.000	0.000	1074	1112	38
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	289	289	0
DTI GSS TET	1441.753	100	1462.818	1441.753	0.000	21.065	1441.753	100	0.000	0.000	3625	3487	-137
Enbridge 16	1600.000	100	1537.223	1528.000	0.000	9.223	1600.000	100	9.168	0.000	5421	5574	153
Enbridge 18	1820.000	100	1792.228	1781.475	0.000	10.753	1820.000	100	10.689	0.000	6177	6349	172
Nat Fuel FSS	1100.000	100	1082.833	1077.960	0.000	4.873	1100.000	100	4.851	0.000	3324	3225	-98
TETCO FSS-1	63.360	100	63.717	63.360	0.000	0.357	63.360	100	0.355	0.000	159	153	-7
TETCO SS-1	1588.950	100	1503.096	1494.679	0.000	8.417	1588.950	100	11.808	0.000	3955	3816	-139
TGP FSMA	1222.594	100	1238.572	1222.594	0.000	15.978	1222.594	100	0.000	0.000	3058	2908	-149
Total	10591.124	100	9861.738	9791.072	0.000	70.666	10591.124	100	36.870	0.000	36521	36322	-199

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2401.791	43.232	2358.559	5840.000	3481.441	8	3939	0	3946	1.6430
TCPL 63398	2273.801	20.464	2253.337	9512.630	7259.293	7	3115	0	3122	1.3731
TCPL 64198	7203.686	129.666	7074.020	21836.855	14762.835	23	11932	0	11955	1.6595
Union 12292	7245.599	31.881	7213.718	21735.750	14522.032	23	2133	0	2156	0.2976
Union 12204	2273.774	10.005	2263.770	9618.480	7354.710	7	944	0	951	0.4184
GS 23-001	1485.491	5.199	1480.291	2172.000	691.709	2	443	0	445	0.2999
PNG 233301 D	164.878	0.462	164.417	3407.500	3243.083	0	2593	0	2593	15.7260
PNG 233301 U	1489.662	4.171	1485.491	1812.000	326.509	2	1394	0	1396	0.9372
PNG 208535 D	3094.412	0.000	3094.412	8577.500	5483.088	5	6557	0	6561	2.1203
PNG 208535 H	2751.130	0.000	2751.130	8030.000	5278.870	4	6138	0	6142	2.2326
PNG 208540	1932.708	0.000	1932.708	5840.000	3907.292	3	3504	0	3507	1.8145
IGT RTS	2253.337	0.000	2253.337	10526.600	8273.263	11	1564	0	1575	0.6991
N Fuel FST I	1091.785	8.953	1082.833	3650.000	2567.167	17	0	0	17	0.0154
N Fuel FST W	1073.109	8.799	1064.310	3650.000	2585.690	16	602	0	619	0.5765
MLP 217524	1359.380	9.380	1350.000	5475.000	4125.000	5	3626	0	3631	2.6711
TGP 95349	746.149	6.044	740.105	3567.510	2827.405	58	714	0	772	1.0352
TGP 5173	2862.340	32.344	2829.996	4653.020	1823.024	294	2793	0	3087	1.0785
TGP 5293	4631.997	52.342	4579.655	4579.655	0.000	475	1043	0	1519	0.3279
TGP 5196	2803.671	31.681	2771.990	5611.875	2839.885	288	1279	0	1566	0.5587
TGP 5196 Wth	1739.362	0.000	1739.362	2007.500	268.138	3	0	0	3	0.0015
TGP 5291 Sup	2200.223	0.000	2200.223	2252.415	52.192	3	0	0	3	0.0015
TGP 5291 5-6	1101.516	8.922	1092.594	2252.415	1159.821	86	451	0	537	0.4873
TGP 5291 NF	1098.707	6.922	1091.785	2252.415	1160.630	69	0	0	69	0.0630
TGP Pool Law	4689.202	0.000	4689.202	13726.920	9037.718	0	0	0	0	0.0000
TGP Pool Spr	7325.136	0.000	7325.136	16214.760	8889.624	0	0	0	0	0.0000
TGP 39741	822.572	6.663	815.910	1489.565	673.655	64	298	0	362	0.4405
TGP 41098	1507.189	12.208	1494.980	6837.545	5342.565	117	1369	0	1486	0.9863
TGP 98775 Up	1032.018	0.000	1032.018	2226.500	1194.482	0	0	0	0	0.0000
TGP 98775 Br	417.447	0.960	416.487	2190.000	1773.513	14	0	0	14	0.0324
TGP 98775 Sp	614.571	1.414	613.158	2226.500	1613.342	20	2007	0	2027	3.2984
TGP 330904 L	2751.130	6.328	2744.802	8030.000	5285.198	89	3808	0	3898	1.4168
TGP 330904 S	6647.269	15.289	6631.980	27156.000	20524.020	216	12880	0	13095	1.9700
TGP 48427	324.439	0.746	323.693	6205.000	5881.307	11	826	0	836	2.5773
TGP 362252	323.693	0.744	322.949	5110.000	4787.051	10	365	0	376	1.1612
Unitil X Bro	515.884	0.000	515.884	1999.105	1483.221	0	0	0	0	0.0000
Unitil X Law	759.872	0.000	759.872	1861.135	1101.263	0	0	0	0	0.0000
Unitil X Spr	204.536	0.000	204.536	504.430	299.894	0	0	0	0	0.0000
AGT AIM	6229.654	188.319	6041.334	10950.000	4908.666	166	15043	0	15209	2.4413

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001EC	8154.640	33.191	8121.449	15467.350	7345.901	318	5324	0	5642	0.6919
AGT 93401	724.025	2.831	721.194	2076.850	1355.656	28	587	0	615	0.8494
AGT 93001F	1494.980	5.083	1489.897	6748.850	5258.953	58	1907	0	1965	1.3144
AGT Hubline	344.167	1.170	342.997	7300.000	6957.003	13	1679	0	1692	4.9176
AGT 510352	6745.662	29.973	6715.689	17520.000	10804.311	263	4949	0	5213	0.7727
AGT 93201 Ce	97.562	0.377	97.185	457.710	360.525	4	129	0	133	1.3644
AGT 93201 La	507.717	1.991	505.726	1545.775	1040.049	20	437	0	457	0.8991
AGT 94501	1487.298	5.863	1481.435	5386.670	3905.235	58	1522	0	1580	1.0622
TET 800414	63.005	0.296	62.709	385.440	322.731	5	123	0	128	2.0331
TET 800462	4317.373	32.812	4284.561	13274.685	8990.124	512	10286	0	10799	2.5013
TET 800382	514.265	2.417	511.848	1545.775	1033.927	38	484	0	522	1.0149
TET Stor Inj	1571.527	4.715	1566.813	364635.000	363068.187	77	0	0	77	0.0489
GSS Stor Inj	1467.219	4.402	1462.818	364635.000	363172.182	72	0	0	72	0.0489
GSS AMA Tran	745.584	3.504	742.080	2376.515	1634.435	56	0	0	56	0.0747
TRANSCO FT	181.904	1.328	180.576	457.710	277.134	4	59	0	62	0.3418
Total		773.092				3642	118847		122489	1.0393

Scenario 2267
EGMA F&SP 2023 - Design Weather - Draw 0

Ventyx
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Report 1

NOV 2026 thru OCT 2027

Cost and Flow Summary

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	202543	Injection Cost	190	Transportation Cost	3838	JAN 15, 2027	
Penalty Cost	0	Withdrawal Cost	227	Other Variable Cost	128	System Served	531.235
Other Variable Cost	0	Carrying Cost	0			System Unserved	0.000
		Other Variable Cost	0			Total	531.235
Total Variable	202543	Total Variable	417	Total Variable	3966		
Demand/Reservation Co	1.912e7	Demand Cost	3193	Demand Cost	118847		
Other Fixed Cost	0	Other Fixed Cost	5160	Other Fixed Cost	0		
Total Fixed	1.912e7	Total Fixed	8353	Total Fixed	118847		
Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0		
Net Supply Cost	1.933e7	Net Storage Cost	8769	Net Trans Cost	122813	Total Gas Cost	19461957
						Total Revenue	0
						Net Cost	19461957

Avg Cost of Served Demand 367.0 USD/DT
(System Cost/Served Dem.)

Avg Cost of Gas Purchased 358.4 USD/DT
(Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	53015.585	0.000	53015.585	0.000	53015.585	53015.585	0.000	0	531.235	0.000
Total	53015.585	0.000	53015.585	0.000	53015.585	53015.585	0.000	0	531.235	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	387.326	364635.000	364247.674			16.2263	6285	0	6285	16.2263
Centerville	5761.764	364635.000	358873.236			4.8469	27927	0	27927	4.8469
Dawn	12111.434	364635.000	352523.566			4.2208	51120	0	51120	4.2208
Dracut	1354.814	364635.000	363280.186			5.1918	7034	0	7034	5.1918
TGP Z4 313	6469.595	364635.000	358165.405			2.5612	16570	0	16570	2.5612
TGP Z4 200	2899.897	364635.000	361735.103			3.5354	10252	0	10252	3.5354
Hereford	1.429	364635.000	364633.571			3.3880	5	0	5	3.3880
LNG Inject	1269.025	364635.000	363365.975			5.5672	7065	0	7065	5.5672
LPG Inject	21.337	364635.000	364613.663			17.0000	363	0	363	17.0000

Scenario 2267
EGMA F&SP 2023 - Design Weather - Draw 0

Ventyx
SENDOUT® Version 14.3.0
Report 1 (Continued)

NOV 2026 thru OCT 2027

Cost and Flow Summary

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Millennium	1948.572	364635.000	362686.428			3.6005	7016	0	7016	3.6005
Niagara	3041.233	364635.000	361593.767			3.3593	10216	0	10216	3.3593
Ramapo	4042.144	364635.000	360592.856			3.2857	13281	0	13281	3.2857
Repsol 30	987.000	987.000	0.000			3.6893	3641	13029226	13032867	13204.5262
Repsol 40	564.000	564.000	0.000			3.6893	2081	6098606	6100687	10816.8205
TETCO M2	9593.999	364635.000	355041.001			2.8781	27613	0	27613	2.8781
TETCO M3	3456.816	364635.000	361178.184			3.3948	11735	0	11735	3.3948
Winter AGT	16.951	2250.000	2233.049			20.0000	339	0	339	20.0000
Winter TGP	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Total	53927.336						202543	19127832	19330375	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	709.753	97	498.831	495.902	0.000	0.000	712.682	97	0.000	2.929	3977	3976	-1
LNG Lawrence	11.628	100	37.256	37.257	0.000	0.000	11.628	100	0.000	0.000	66	71	4
LNG Marshfld	7.622	100	19.238	19.238	0.000	0.000	7.622	100	0.000	0.000	46	47	1
LNG Spring	919.961	97	713.700	713.700	0.000	0.000	919.961	97	0.000	0.000	5145	5122	-23
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	173	173	0
LPG Meadow	70.749	100	21.000	21.000	0.000	0.000	70.749	100	0.000	0.000	1112	1139	27
LPG NHampton	21.722	100	0.337	0.337	0.000	0.000	21.722	100	0.000	0.000	289	290	1
DTI GSS TET	1441.753	100	1462.818	1441.753	0.000	21.065	1441.753	100	0.000	0.000	3487	3393	-95
Enbridge 16	1600.000	100	1534.326	1525.120	0.000	9.206	1600.000	100	9.151	0.000	5574	5587	13
Enbridge 18	1820.000	100	1792.228	1781.475	0.000	10.753	1820.000	100	10.689	0.000	6349	6361	11
Nat Fuel FSS	1100.000	100	1068.106	1063.300	0.000	4.806	1100.000	100	4.785	0.000	3225	3092	-133
TETCO FSS-1	63.360	100	63.717	63.360	0.000	0.357	63.360	100	0.355	0.000	153	149	-4
TETCO SS-1	1588.950	100	1503.096	1494.679	0.000	8.417	1588.950	100	11.808	0.000	3816	3709	-106
TGP FSMA	1222.594	100	1238.572	1222.594	0.000	15.978	1222.594	100	0.000	0.000	2908	2771	-137
Total	10591.124	100	9953.225	9879.714	0.000	70.582	10594.053	100	36.787	2.929	36322	35879	-442

NOV 2026 thru OCT 2027 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2399.891	43.198	2356.693	5840.000	3483.307	8	3939	0	3946	1.6443
TCPL 63398	2305.872	20.753	2285.119	9512.630	7227.511	7	3115	0	3122	1.3540
TCPL 64198	7323.315	131.820	7191.496	21836.855	14645.359	23	11932	0	11955	1.6325
Union 12292	7363.956	32.401	7331.554	21735.750	14404.196	23	2133	0	2157	0.2929
Union 12204	2307.788	10.154	2297.633	9618.480	7320.847	7	944	0	951	0.4123
GS 23-001	1499.413	5.248	1494.165	2172.000	677.835	2	443	0	445	0.2971
PNG 233301 D	170.356	0.477	169.879	3407.500	3237.621	0	2593	0	2593	15.2204
PNG 233301 U	1503.623	4.210	1499.413	1812.000	312.587	2	1394	0	1396	0.9285
PNG 208535 D	3165.236	0.000	3165.236	8577.500	5412.264	5	6557	0	6561	2.0729
PNG 208535 H	2700.547	0.000	2700.547	8030.000	5329.453	4	6138	0	6142	2.2744
PNG 208540	2009.855	0.000	2009.855	5840.000	3830.145	3	3504	0	3507	1.7449
IGT RTS	2285.119	0.000	2285.119	10526.600	8241.481	11	1564	0	1575	0.6894
N Fuel FST I	1076.937	8.831	1068.106	3650.000	2581.894	17	0	0	17	0.0154
N Fuel FST W	1058.515	8.680	1049.835	3650.000	2600.165	16	602	0	618	0.5842
MLP 217524	1948.572	13.445	1935.127	5475.000	3539.873	7	3626	0	3633	1.8645
TGP 95349	778.181	6.303	771.877	3567.510	2795.633	61	714	0	775	0.9958
TGP 5173	2899.897	32.769	2867.128	4653.020	1785.892	298	2793	0	3091	1.0659
TGP 5293	4631.997	52.342	4579.655	4579.655	0.000	475	1043	0	1519	0.3279
TGP 5196	2871.456	32.447	2839.009	5611.875	2772.866	295	1279	0	1573	0.5479
TGP 5196 Wth	1821.621	0.000	1821.621	2007.500	185.879	3	0	0	3	0.0015
TGP 5291 Sup	2212.524	0.000	2212.524	2252.415	39.891	3	0	0	3	0.0015
TGP 5291 5-6	1128.758	9.143	1119.615	2252.415	1132.800	88	451	0	539	0.4774
TGP 5291 NF	1083.765	6.828	1076.937	2252.415	1175.478	68	0	0	68	0.0630
TGP Pool Law	4909.705	0.000	4909.705	13726.920	8817.215	0	0	0	0	0.0000
TGP Pool Spr	7267.580	0.000	7267.580	16214.760	8947.180	0	0	0	0	0.0000
TGP 39741	828.709	6.713	821.997	1489.565	667.569	65	298	0	363	0.4378
TGP 41098	1506.939	12.206	1494.732	6837.545	5342.813	117	1369	0	1486	0.9864
TGP 98775 Up	1028.397	0.000	1028.397	2226.500	1198.103	0	0	0	0	0.0000
TGP 98775 Br	358.126	0.824	357.302	2190.000	1832.698	12	0	0	12	0.0324
TGP 98775 Sp	670.271	1.542	668.729	2226.500	1557.771	22	2007	0	2029	3.0270
TGP 330904 L	2700.547	6.211	2694.336	8030.000	5335.664	88	3808	0	3896	1.4427
TGP 330904 S	6866.137	15.792	6850.345	27156.000	20305.655	223	12880	0	13102	1.9082
TGP 48427	356.251	0.819	355.431	6205.000	5849.569	12	826	0	837	2.3501
TGP 362252	355.431	0.817	354.614	5110.000	4755.386	12	365	0	377	1.0604
Unitil X Bro	527.209	0.000	527.209	1999.105	1471.896	0	0	0	0	0.0000
Unitil X Law	759.656	0.000	759.656	1861.135	1101.479	0	0	0	0	0.0000
Unitil X Spr	207.300	0.000	207.300	504.430	297.130	0	0	0	0	0.0000
AGT AIM	5977.272	185.206	5792.065	10950.000	5157.935	159	15043	0	15202	2.5433

NOV 2026 thru OCT 2027 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001EC	10087.882	44.494	10043.388	15467.350	5423.962	394	5324	0	5718	0.5668
AGT 93401	731.233	2.878	728.355	2076.850	1348.495	29	587	0	615	0.8414
AGT 93001F	1494.732	5.082	1489.650	6748.850	5259.200	58	1907	0	1965	1.3146
AGT Hubline	387.326	1.317	386.009	7300.000	6913.991	15	1679	0	1694	4.3740
AGT 510352	5851.169	24.324	5826.845	17520.000	11693.155	228	4949	0	5178	0.8849
AGT 93201 Ce	91.172	0.351	90.821	457.710	366.889	4	129	0	133	1.4573
AGT 93201 La	495.503	1.896	493.607	1545.775	1052.168	19	437	0	456	0.9203
AGT 94501	1447.137	5.450	1441.688	5386.670	3944.982	57	1522	0	1578	1.0906
TET 800414	63.005	0.296	62.709	385.440	322.731	5	123	0	128	2.0331
TET 800462	6555.253	49.820	6505.433	13274.685	6769.252	778	10286	0	11064	1.6879
TET 800382	517.331	2.431	514.899	1545.775	1030.876	39	484	0	522	1.0094
TET Stor Inj	1571.527	4.715	1566.813	364635.000	363068.187	77	0	0	77	0.0489
GSS Stor Inj	1467.219	4.402	1462.818	364635.000	363172.182	72	0	0	72	0.0489
GSS AMA Tran	742.519	3.490	739.029	2376.515	1637.486	56	0	0	56	0.0747
TRANSCO FT	181.904	1.328	180.576	457.710	277.134	4	59	0	62	0.3418
Total		801.453				3966	118847		122813	1.0021

Scenario 2267
EGMA F&SP 2023 - Design Weather - Draw 0

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Report 1

NOV 2027 thru OCT 2028

Cost and Flow Summary

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	204667	Injection Cost	189	Transportation Cost	4014	JAN 15, 2028	
Penalty Cost	0	Withdrawal Cost	227	Other Variable Cost	132	System Served	538.418
Other Variable Cost	0	Carrying Cost	0			System Unserved	0.000
		Other Variable Cost	0			Total	538.418
Total Variable	204667	Total Variable	417	Total Variable	4146		
Demand/Reservation Co	1.912e7	Demand Cost	3193	Demand Cost	118847		
Other Fixed Cost	0	Other Fixed Cost	5160	Other Fixed Cost	0		
Total Fixed	1.912e7	Total Fixed	8353	Total Fixed	118847		
Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0		
Net Supply Cost	1.933e7	Net Storage Cost	8769	Net Trans Cost	122993	Total Gas Cost	19464261
						Total Revenue	0
						Net Cost	19464261

Avg Cost of Served Demand 360.3 USD/DT
(System Cost/Served Dem.)

Avg Cost of Gas Purchased 351.9 USD/DT
(Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	54013.575	0.000	54013.575	0.000	54013.575	54013.575	0.000	0	538.418	0.000
Total	54013.575	0.000	54013.575	0.000	54013.575	54013.575	0.000	0	538.418	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	401.136	365634.000	365232.864			16.1067	6461	0	6461	16.1067
Centerville	6335.377	365634.000	359298.623			4.7094	29836	0	29836	4.7094
Dawn	12306.580	365634.000	353327.420			4.1778	51415	0	51415	4.1778
Dracut	1453.169	365634.000	364180.831			5.1189	7439	0	7439	5.1189
TGP Z4 313	6547.959	365634.000	359086.041			2.6128	17108	0	17108	2.6128
TGP Z4 200	2951.830	365634.000	362682.170			3.4513	10188	0	10188	3.4513
Hereford	2.385	365634.000	365631.615			3.3530	8	0	8	3.3530
LNG Inject	1297.933	365634.000	364336.067			5.5419	7193	0	7193	5.5419
LPG Inject	24.284	365634.000	365609.716			17.0000	413	0	413	17.0000

Scenario 2267
EGMA F&SP 2023 - Design Weather - Draw 0

Ventyx
SENDOUT® Version 14.3.0
Report 1 (Continued)

NOV 2027 thru OCT 2028

Cost and Flow Summary

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Millennium	1971.328	365634.000	363662.672			3.6635	7222	0	7222	3.6635
Niagara	3066.776	365634.000	362567.224			3.3101	10151	0	10151	3.3101
Ramapo	3991.964	365634.000	361642.036			3.2073	12804	0	12804	3.2073
Repsol 30	987.000	987.000	0.000			3.6713	3624	13029226	13032850	13204.5082
Repsol 40	564.000	564.000	0.000			3.6713	2071	6098606	6100677	10816.8025
TETCO M2	10653.009	365634.000	354980.991			2.8238	30082	0	30082	2.8238
TETCO M3	2355.990	365634.000	363278.010			3.4935	8231	0	8231	3.4935
Winter AGT	21.187	2275.000	2253.813			20.0000	424	0	424	20.0000
Winter TGP	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Total	54931.907						204667	19127832	19332499	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	712.682	97	495.902	498.831	0.000	0.000	709.753	97	0.000	-2.929	3976	3943	-33
LNG Lawrence	11.628	100	36.971	37.320	0.000	0.000	11.279	97	0.000	-0.349	71	72	1
LNG Marshfld	7.622	100	19.037	19.266	0.000	0.000	7.393	97	0.000	-0.229	47	46	-2
LNG Spring	919.961	97	746.023	746.023	0.000	0.000	919.961	97	0.000	0.000	5122	5097	-24
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	173	173	0
LPG Meadow	70.749	100	21.000	21.000	0.000	0.000	70.749	100	0.000	0.000	1139	1158	19
LPG NHampton	21.722	100	3.284	3.284	0.000	0.000	21.722	100	0.000	0.000	290	302	12
DTI GSS TET	1441.753	100	1448.603	1427.743	0.000	20.860	1441.753	100	0.000	0.000	3393	3461	68
Enbridge 16	1600.000	100	1534.326	1525.120	0.000	9.206	1600.000	100	9.151	0.000	5587	5565	-22
Enbridge 18	1820.000	100	1784.764	1774.055	0.000	10.709	1820.000	100	10.644	0.000	6361	6335	-26
Nat Fuel FSS	1100.000	100	1075.470	1070.630	0.000	4.840	1100.000	100	4.818	0.000	3092	3114	22
TETCO FSS-1	63.360	100	63.717	63.360	0.000	0.357	63.360	100	0.355	0.000	149	151	3
TETCO SS-1	1588.950	100	1503.096	1494.679	0.000	8.417	1588.950	100	11.808	0.000	3709	3793	84
TGP FSMA	1222.594	100	1238.572	1222.594	0.000	15.978	1222.594	100	0.000	0.000	2771	2912	141
Total	10594.053	100	9970.764	9903.904	0.000	70.366	10590.547	100	36.776	-3.506	35879	36123	243

NOV 2027 thru OCT 2028 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2407.726	43.339	2364.387	5856.000	3491.613	8	3939	0	3946	1.6390
TCPL 63398	2360.746	21.247	2339.500	9538.692	7199.192	7	3115	0	3122	1.3226
TCPL 64198	7455.018	134.190	7320.828	21896.682	14575.854	23	11932	0	11956	1.6037
Union 12292	7430.005	32.692	7397.313	21795.300	14397.987	24	2133	0	2157	0.2903
Union 12204	2429.140	10.688	2418.452	9644.832	7226.380	8	944	0	952	0.3918
GS 23-001	1510.406	5.286	1505.119	2184.000	678.881	2	443	0	446	0.2950
PNG 233301 D	181.147	0.507	180.640	3409.800	3229.160	0	2593	0	2593	14.3138
PNG 233301 U	1514.647	4.241	1510.406	1824.000	313.594	2	1394	0	1396	0.9218
PNG 208535 D	3199.658	0.000	3199.658	8601.000	5401.342	5	6557	0	6561	2.0506
PNG 208535 H	2766.617	0.000	2766.617	8052.000	5285.383	4	6138	0	6142	2.2201
PNG 208540	2025.531	0.000	2025.531	5856.000	3830.469	3	3504	0	3507	1.7314
IGT RTS	2339.500	0.000	2339.500	10555.440	8215.940	11	1564	0	1576	0.6735
N Fuel FST I	1084.361	8.892	1075.470	3660.000	2584.530	17	0	0	17	0.0154
N Fuel FST W	1065.812	8.740	1057.073	3660.000	2602.927	16	602	0	618	0.5803
MLP 217524	1971.328	13.602	1957.726	5490.000	3532.274	7	3626	0	3633	1.8430
TGP 95349	784.607	6.355	778.252	3577.284	2799.032	61	714	0	775	0.9883
TGP 5173	2951.830	33.356	2918.474	4665.768	1747.294	303	2793	0	3096	1.0490
TGP 5293	4644.687	52.485	4592.202	4592.202	0.000	477	1043	0	1520	0.3273
TGP 5196	2944.367	33.271	2911.095	5627.250	2716.155	302	1279	0	1581	0.5369
TGP 5196 Wth	1887.294	0.000	1887.294	2013.000	125.706	3	0	0	3	0.0015
TGP 5291 Sup	2225.251	0.000	2225.251	2258.586	33.335	3	0	0	3	0.0015
TGP 5291 5-6	1134.015	9.186	1124.830	2258.586	1133.756	88	451	0	539	0.4756
TGP 5291 NF	1091.236	6.875	1084.361	2258.586	1174.225	69	0	0	69	0.0630
TGP Pool Law	4991.733	0.000	4991.733	13764.528	8772.795	0	0	0	0	0.0000
TGP Pool Spr	7333.120	0.000	7333.120	16259.184	8926.064	0	0	0	0	0.0000
TGP 39741	841.525	6.816	834.708	1493.646	658.938	66	298	0	364	0.4323
TGP 41098	1554.893	12.595	1542.298	6856.278	5313.980	121	1369	0	1490	0.9584
TGP 98775 Up	1041.921	0.000	1041.921	2232.600	1190.679	0	0	0	0	0.0000
TGP 98775 Br	358.154	0.824	357.330	2196.000	1838.670	12	0	0	12	0.0324
TGP 98775 Sp	683.767	1.573	682.195	2232.600	1550.405	22	2007	0	2029	2.9679
TGP 330904 L	2766.617	6.363	2760.253	8052.000	5291.747	90	3808	0	3898	1.4090
TGP 330904 S	6999.145	16.098	6983.047	27230.400	20247.353	227	12880	0	13106	1.8726
TGP 48427	368.932	0.849	368.083	6222.000	5853.917	12	826	0	838	2.2704
TGP 362252	368.083	0.847	367.236	5124.000	4756.764	12	365	0	377	1.0251
Unitil X Bro	535.843	0.000	535.843	2004.582	1468.739	0	0	0	0	0.0000
Unitil X Law	763.637	0.000	763.637	1866.234	1102.597	0	0	0	0	0.0000
Unitil X Spr	205.640	0.000	205.640	505.812	300.172	0	0	0	0	0.0000
AGT AIM	5949.689	181.242	5768.447	10980.000	5211.553	158	15043	0	15201	2.5549

NOV 2027 thru OCT 2028 | Cost and Flow Summary | Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001EC	10096.465	44.701	10051.764	15518.982	5467.218	394	5324	0	5718	0.5663
AGT 93401	736.390	2.970	733.420	2082.540	1349.120	29	587	0	615	0.8358
AGT 93001F	1542.298	5.244	1537.054	6767.340	5230.286	60	1907	0	1967	1.2752
AGT Hubline	401.136	1.364	399.772	7320.000	6920.228	16	1679	0	1695	4.2247
AGT 510352	6354.323	25.627	6328.696	17568.000	11239.304	248	4949	0	5197	0.8179
AGT 93201 Ce	125.820	0.482	125.338	458.964	333.626	5	129	0	134	1.0667
AGT 93201 La	496.686	1.986	494.700	1550.010	1055.310	19	437	0	456	0.9182
AGT 94501	1418.460	5.730	1412.729	5401.428	3988.699	55	1522	0	1577	1.1118
TET 800414	63.005	0.296	62.709	386.496	323.787	5	123	0	128	2.0331
TET 800462	7628.520	57.977	7570.543	13311.054	5740.511	905	10286	0	11192	1.4671
TET 800382	515.881	2.425	513.457	1550.010	1036.553	39	484	0	522	1.0120
TET Stor Inj	1571.527	4.715	1566.813	365634.000	364067.187	77	0	0	77	0.0489
GSS Stor Inj	1452.962	4.359	1448.603	365634.000	364185.397	71	0	0	71	0.0489
GSS AMA Tran	766.032	3.600	762.431	2383.026	1620.595	57	0	0	57	0.0747
TRANSCO FT	145.830	1.065	144.766	458.964	314.198	3	59	0	61	0.4216
Total		814.697				4146	118847		122993	0.9802

Scenario 2267
EGMA F&SP 2023 - Design Weather - Draw 0

Ventyx
SENDOUT® Version 14.3.0
Report 1z

NOV 2023 thru OCT 2028

Cost and Flow Summary

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	954138	Injection Cost	942	Transportation Cost	18998	JAN 15, 2028	
Penalty Cost	0	Withdrawal Cost	1130	Other Variable Cost	640	System Served	538.418
Other Variable Cost	0	Carrying Cost	0			System Unserved	0.000
		Other Variable Cost	0			Total	538.418
Total Variable	954138	Total Variable	2071	Total Variable	19638		
Demand/Reservation Co	9.563e7	Demand Cost	15964	Demand Cost	594234		
Other Fixed Cost	0	Other Fixed Cost	25396	Other Fixed Cost	0		
Total Fixed	9.563e7	Total Fixed	41361	Total Fixed	594234		
Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0		
Net Supply Cost	9.659e7	Net Storage Cost	43432	Net Trans Cost	613872	Total Gas Cost	97250602
						Total Revenue	0
						Net Cost	97250602

Avg Cost of Served Demand 371.5 USD/DT
(System Cost/Served Dem.)

Avg Cost of Gas Purchased 362.7 USD/DT
(Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	261746.491	0.000	261746.491	0.000	261746.491	261746.491	0.000	0	538.418	0.000
Total	261746.491	0.000	261746.491	0.000	261746.491	261746.491	0.000	0	538.418	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	1812.035	1825173.00	1823360.96			15.7621	28561	0	28561	15.7621
Centerville	28114.375	1825173.00	1797058.62			4.6179	129829	0	129829	4.6179
Dawn	61700.242	1825173.00	1763472.75			3.8946	240297	0	240297	3.8946
Dracut	4899.832	1825173.00	1820273.16			5.7436	28142	0	28142	5.7436
TGP Z4 313	32064.500	1825173.00	1793108.50			2.5444	81583	0	81583	2.5444
TGP Z4 200	14410.362	1825173.00	1810762.63			3.3419	48158	0	48158	3.3419
Hereford	4.025	1825173.00	1825168.97			3.3691	14	0	14	3.3691
LNG Inject	5918.495	1825173.00	1819254.50			5.4955	32525	0	32525	5.4955
LPG Inject	108.621	1825173.00	1825064.37			17.0000	1847	0	1847	17.0000

Scenario 2267
EGMA F&SP 2023 - Design Weather - Draw 0

Ventyx
SENDOUT® Version 14.3.0
Report 1z (Continued)

NOV 2023 thru OCT 2028 Cost and Flow Summary

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Millennium	11216.576	1825173.00	1813956.42			3.2862	36860	0	36860	3.2862
Niagara	15153.949	1825173.00	1810019.05			3.2237	48852	0	48852	3.2237
Ramapo	20861.610	1825173.00	1804311.39			3.1711	66153	0	66153	3.1711
Repsol 30	4935.000	4935.000	0.000			3.3368	16467	65146130	65162597	13204.1737
Repsol 40	2820.000	2820.000	0.000			3.3368	9410	30493030	30502440	10816.4680
TETCO M2	47664.616	1825173.00	1777508.38			2.8314	134958	0	134958	2.8314
TETCO M3	14514.717	1825173.00	1810658.28			3.3803	49064	0	49064	3.3803
Winter AGT	70.871	11300.000	11229.129			20.0000	1417	0	1417	20.0000
Winter TGP	0.000	0.000	0.000			0.0000	0	0	0	0.0000
Total	266269.828						954138	95639160	96593298	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	731.704	100	2272.699	2294.650	0.000	0.000	709.753	97	0.000	-21.951	4527	3943	-584
LNG Lawrence	11.628	100	175.645	175.993	0.000	0.000	11.279	97	0.000	-0.349	72	72	0
LNG Marshfld	7.622	100	96.017	96.246	0.000	0.000	7.393	97	0.000	-0.229	47	46	-1
LNG Spring	948.413	100	3374.135	3402.587	0.000	0.000	919.961	97	0.000	-28.452	5868	5097	-771
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	173	173	0
LPG Meadow	70.749	100	105.000	105.000	0.000	0.000	70.749	100	0.000	0.000	942	1158	216
LPG NHampton	21.722	100	3.621	3.621	0.000	0.000	21.722	100	0.000	0.000	289	302	13
DTI GSS TET	1441.753	100	7243.144	7138.843	0.000	104.301	1441.753	100	0.000	0.000	4259	3461	-798
Enbridge 16	1600.000	100	7581.328	7535.840	0.000	45.488	1600.000	100	45.215	0.000	7976	5565	-2411
Enbridge 18	1820.000	100	8876.775	8823.514	0.000	53.261	1820.000	100	52.941	0.000	9149	6335	-2814
Nat Fuel FSS	1100.000	100	5266.901	5243.200	0.000	23.701	1100.000	100	23.594	0.000	5454	3114	-2340
TETCO FSS-1	63.360	100	318.584	316.800	0.000	1.784	63.360	100	1.774	0.000	277	151	-126
TETCO SS-1	1588.950	100	7515.480	7473.393	0.000	42.087	1588.950	100	59.040	0.000	4838	3793	-1045
TGP FSMA	1222.594	100	6192.858	6112.970	0.000	79.888	1222.594	100	0.000	0.000	6133	2912	-3221
Total	10641.528	100	49022.187	48722.65	0.000	350.510	10590.547	100	182.564	-50.981	50004	36123	-13881

NOV 2023 thru OCT 2028 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	12694.335	228.498	12465.837	29232.000	16766.163	40	19693	0	19733	1.5545
TCPL 63398	11560.811	104.047	11456.764	47615.274	36158.510	37	15574	0	15611	1.3503
TCPL 64198	37033.432	666.602	36366.830	109303.929	72937.099	116	59661	0	59777	1.6141
Union 12292	36111.924	158.892	35953.032	108797.850	72844.818	115	10667	0	10782	0.2986
Union 12204	12697.078	55.867	12641.211	48145.104	35503.893	40	4720	0	4761	0.3749
GS 23-001	7481.631	26.186	7455.445	10884.000	3428.555	11	2216	0	2227	0.2977
PNG 233301 D	876.842	2.455	874.387	17042.100	16167.713	1	12963	0	12964	14.7854
PNG 233301 U	7502.638	21.007	7481.631	9084.000	1602.369	11	6969	0	6981	0.9304
PNG 208535 D	16488.846	0.000	16488.846	42934.500	26445.654	25	32783	0	32807	1.9897
PNG 208535 H	13799.989	0.000	13799.989	40194.000	26394.011	21	30690	0	30711	2.2254
PNG 208540	10168.377	0.000	10168.377	29232.000	19063.623	15	17520	0	17535	1.7245
IGT RTS	11456.764	0.000	11456.764	52690.680	41233.916	56	7821	0	7877	0.6876
N Fuel FST I	5310.447	43.546	5266.901	18270.000	13003.099	82	0	0	82	0.0154
N Fuel FST W	5219.606	42.801	5176.805	18270.000	13093.195	80	3011	0	3091	0.5921
MLP 217524	11216.576	77.394	11139.182	27405.000	16265.818	38	18132	0	18170	1.6199
TGP 95349	3875.061	31.388	3843.673	17857.098	14013.425	302	3572	0	3873	0.9996
TGP 5173	14410.362	162.837	14247.525	23290.596	9043.071	1479	13967	0	15446	1.0719
TGP 5293	23185.364	261.995	22923.369	22923.369	0.000	2379	5217	0	7597	0.3276
TGP 5196	13976.054	157.929	13818.124	28090.125	14272.001	1434	6393	0	7827	0.5601
TGP 5196 Wth	8799.249	0.000	8799.249	10048.500	1249.251	13	0	0	13	0.0015
TGP 5291 Sup	11021.241	0.000	11021.241	11274.417	253.176	17	0	0	17	0.0015
TGP 5291 5-6	5677.126	45.985	5631.141	11274.417	5643.276	442	2255	0	2697	0.4751
TGP 5291 NF	5344.115	33.668	5310.447	11274.417	5963.970	337	0	0	337	0.0630
TGP Pool Law	23985.670	0.000	23985.670	68709.816	44724.146	0	0	0	0	0.0000
TGP Pool Spr	36478.162	0.000	36478.162	81162.648	44684.486	0	0	0	0	0.0000
TGP 39741	4132.708	33.475	4099.233	7455.987	3356.754	322	1491	0	1813	0.4387
TGP 41098	7581.703	61.412	7520.291	34225.191	26704.900	590	6846	0	7436	0.9808
TGP 98775 Up	5070.999	0.000	5070.999	11144.700	6073.701	0	0	0	0	0.0000
TGP 98775 Br	1868.954	4.299	1864.655	10962.000	9097.345	61	0	0	61	0.0324
TGP 98775 Sp	3202.045	7.365	3194.681	11144.700	7950.019	104	10036	0	10140	3.1667
TGP 330904 L	13799.989	31.740	13768.249	40194.000	26425.751	447	19042	0	19490	1.4123
TGP 330904 S	33506.352	77.065	33429.287	135928.800	102499.513	1086	64398	0	65484	1.9544
TGP 48427	1609.091	3.701	1605.390	31059.000	29453.610	52	4128	0	4181	2.5981
TGP 362252	1605.390	3.692	1601.698	25578.000	23976.302	52	1827	0	1879	1.1704
Unitil X Bro	2621.980	0.000	2621.980	10006.479	7384.499	0	0	0	0	0.0000
Unitil X Law	3801.389	0.000	3801.389	9315.873	5514.484	0	0	0	0	0.0000
Unitil X Spr	1032.076	0.000	1032.076	2524.914	1492.838	0	0	0	0	0.0000
AGT AIM	32000.792	960.428	31040.364	54810.000	23769.636	851	75215	0	76066	2.3770

NOV 2023 thru OCT 2028 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001EC	46960.349	202.068	46758.280	77440.014	30681.734	1833	26619	0	28452	0.6059
AGT 93401	3730.490	14.927	3715.563	10395.630	6680.067	146	2934	0	3079	0.8254
AGT 93001F	7520.291	25.569	7494.722	33781.230	26286.508	294	9533	0	9827	1.3067
AGT Hubline	1812.035	6.161	1805.874	36540.000	34734.126	71	8395	0	8466	4.6720
AGT 510352	28447.842	116.475	28331.367	87696.000	59364.633	1111	24747	0	25858	0.9089
AGT 93201 Ce	477.172	1.794	475.378	2291.058	1815.680	19	647	0	665	1.3939
AGT 93201 La	2552.700	10.073	2542.626	7737.345	5194.719	100	2183	0	2283	0.8944
AGT 94501	7586.326	30.060	7556.266	26962.866	19406.600	296	7609	0	7905	1.0420
TET 800414	315.026	1.481	313.545	1929.312	1615.767	24	617	0	640	2.0331
TET 800462	32542.040	247.320	32294.721	66446.163	34151.442	3862	51432	0	55295	1.6992
TET 800382	2572.458	12.091	2560.367	7737.345	5176.978	192	2418	0	2610	1.0145
TET Stor Inj	7857.637	23.573	7834.064	1825173.00	1817338.93	384	0	0	384	0.0489
GSS Stor Inj	7264.939	21.795	7243.144	1825173.00	1817929.85	355	0	0	355	0.0489
GSS AMA Tran	3749.784	17.624	3732.160	11895.597	8163.437	280	0	0	280	0.0747
TRANSCO FT	816.601	5.961	810.640	2291.058	1480.418	16	293	0	309	0.3785
Total		4041.244				19638	594234		613872	1.0024

Natural Gas Supply VS. Requirements — Units: MDT

	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	OCT 2024	Total
Forecast Demand													
Demand	5237.517	7775.398	10452.40	8452.631	7608.331	3836.897	1843.365	1145.009	1043.522	1043.522	1173.909	2118.347	51730.851
Total Demand	5237.517	7775.398	10452.40	8452.631	7608.331	3836.897	1843.365	1145.009	1043.522	1043.522	1173.909	2118.347	51730.851
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	83.012	132.044	154.158	134.836	128.565	52.046	30.135	22.386	23.918	24.022	18.318	27.864	831.303
Injection	0.000	0.000	0.000	0.000	0.000	4.792	13.550	13.480	5.783	9.048	13.397	8.922	68.973
Withdrawal	0.057	3.541	14.786	12.188	4.954	0.000	0.000	0.000	0.000	0.000	0.000	0.000	35.526
Total Fuel	83.069	135.585	168.944	147.025	133.518	56.838	43.685	35.866	29.701	33.070	31.715	36.786	935.803
Storage Injections													
LNG Easton	12.514	0.000	0.000	0.000	0.000	150.000	155.000	39.841	15.841	0.000	31.171	15.841	420.207
LNG Lawrence	1.913	1.976	0.000	1.142	1.976	2.130	13.829	2.130	2.201	0.000	4.331	2.201	33.829
LNG Marshfld	0.835	0.863	1.213	0.807	0.863	0.990	8.645	0.990	1.023	0.000	2.013	1.023	19.266
LNG Spring	27.072	0.000	0.000	0.000	0.000	132.849	310.000	32.250	33.325	0.000	65.575	33.325	634.396
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	20.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	244.734	236.840	210.563	244.734	236.840	244.734	1418.446
Enbridge 16	0.000	0.000	0.000	0.000	0.000	357.840	369.768	357.840	0.000	0.000	344.152	0.000	1429.600
Enbridge 18	0.000	0.000	0.000	0.000	0.000	407.043	420.611	407.043	63.559	0.000	407.043	0.000	1705.299
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	34.194	103.756	181.634	187.689	187.689	181.634	135.394	1011.990
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.712	10.049	9.725	10.049	10.049	9.725	10.049	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.821	243.698	251.821	251.821	243.698	251.821	1494.679
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	249.421	241.376	0.000	241.000	241.376	249.421	1222.594
Total Inj	42.333	2.839	21.213	1.950	3.839	1088.758	2137.636	1753.366	776.071	935.293	1767.557	943.811	9474.666
Total Req	5362.919	7913.822	10642.56	8601.605	7745.689	4982.493	4024.686	2934.241	1849.294	2011.885	2973.181	3098.943	62141.319
Sources of Supply													
Beverly	0.000	23.057	205.607	80.303	36.980	0.000	0.000	0.000	0.000	0.000	0.000	0.000	345.947
Centerville	180.920	929.580	1256.901	956.582	684.798	16.201	0.000	0.000	0.000	0.000	0.000	128.795	4153.777
Dawn	1286.326	2769.694	1846.102	1701.765	1360.113	1382.863	795.150	769.500	63.942	0.000	755.729	0.000	12731.185
Dracut	7.304	7.242	67.633	21.727	245.152	0.000	6.019	0.000	0.000	0.000	0.000	36.131	391.207
TGP Z4 313	545.712	563.902	2.575	56.962	373.196	542.703	793.835	726.866	470.628	714.778	739.163	810.269	6340.589
TGP Z4 200	382.537	399.705	399.705	373.917	386.811	355.990	205.896	22.889	0.000	0.000	39.108	289.256	2855.814

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	OCT 2024	Total
Sources of Supply													
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Inject	42.333	2.839	1.213	1.950	2.839	285.969	487.474	75.211	52.390	0.000	103.090	52.390	1107.699
LPG Inject	0.000	0.000	20.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
Millennium	424.256	468.231	468.231	438.022	453.127	0.000	0.000	0.000	468.231	468.231	0.000	0.000	3188.328
Niagara	298.274	318.845	318.845	298.274	308.560	296.217	176.168	185.130	191.301	191.301	185.130	248.807	3016.853
Ramapo	393.174	59.813	248.883	147.400	475.527	903.748	817.043	599.257	71.991	71.991	0.000	0.000	3788.827
Repsol 30	0.000	120.485	569.194	297.321	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	101.620	305.668	156.712	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1088.309	1136.073	1136.073	1062.778	1133.658	3.744	513.195	496.640	478.420	513.195	1100.262	1480.905	10143.252
TETCO M3	658.767	33.478	109.459	98.227	790.637	1144.359	177.516	8.048	0.000	0.000	0.000	0.000	3020.491
Winter AGT	0.000	0.000	10.685	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	10.685
Winter TGP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	5307.913	6934.566	6966.773	5691.940	6252.399	4931.793	3972.296	2883.541	1796.904	1959.495	2922.481	3046.553	52666.653
Storage Withdrawals													
LNG Easton	12.514	24.982	173.894	64.418	35.045	15.330	15.841	15.330	15.841	15.841	15.330	15.841	420.207
LNG Lawrence	1.912	1.976	10.922	1.849	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	33.829
LNG Marshfld	0.835	0.863	8.835	0.807	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	19.266
LNG Spring	27.072	30.403	207.204	86.661	53.006	32.250	33.325	32.250	33.325	33.325	32.250	33.325	634.396
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	373.859	373.859	349.739	320.989	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1418.446
Enbridge 16	0.000	110.179	496.000	464.000	359.421	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1429.600
Enbridge 18	0.000	0.000	797.000	637.325	270.974	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1705.299
Nat Fuel FSS	12.672	162.195	294.131	282.681	260.310	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1011.990
TETCO FSS-1	0.000	9.149	32.736	21.475	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	265.651	698.879	530.149	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1494.679
TGP FSMA	0.000	0.000	561.328	470.560	190.706	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	55.006	979.256	3675.788	2909.665	1493.290	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9474.666
Total Supply	5362.919	7913.822	10642.56	8601.605	7745.689	4982.493	4024.686	2934.241	1849.294	2011.885	2973.181	3098.943	62141.319
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	OCT 2024	Total
Net Storage Inv. Adj.													
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	731.704	731.704	706.722	532.828	468.409	433.364	568.034	707.193	731.704	731.704	715.863	731.704	731.704
LNG Lawrence	11.628	11.628	11.628	0.706	0.000	0.000	0.000	11.628	11.628	11.628	9.427	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	7.622	6.599	7.622	7.622
LNG Spring	948.413	948.413	918.010	710.806	624.145	571.139	671.738	948.413	948.413	948.413	915.088	948.413	948.413
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	69.749	69.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1441.753	1067.894	694.035	344.296	23.307	23.307	268.042	504.881	715.445	960.179	1197.019	1441.753
Enbridge 16	1600.000	1600.000	1489.821	993.821	529.821	170.400	528.240	898.008	1255.848	1255.848	1255.848	1600.000	1600.000
Enbridge 18	1820.000	1820.000	1820.000	1023.000	385.675	114.701	521.744	942.355	1349.398	1412.957	1412.957	1820.000	1820.000
Nat Fuel FSS	1100.000	1087.328	925.133	631.001	348.320	88.010	122.204	225.960	407.594	595.283	782.971	964.606	1100.000
TETCO FSS-1	63.360	63.360	54.211	21.475	0.000	0.000	3.712	13.761	23.487	33.536	43.585	53.311	63.360
TETCO SS-1	1588.950	1588.950	1323.299	624.420	94.271	94.271	94.271	346.092	589.790	841.611	1093.432	1337.129	1588.950
TGP FSMA	1222.594	1222.594	1222.594	661.266	190.706	0.000	0.000	249.421	490.797	490.797	731.797	973.173	1222.594
Total Inv	10641.52	10628.85	9652.439	5997.863	3090.148	1600.697	2638.754	4724.000	6426.666	7150.347	8033.250	9750.107	10641.528
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	OCT 2025	Total
Forecast Demand													
Demand	5171.597	7669.611	10424.60	8426.074	7581.289	3782.239	1809.829	1116.869	1005.950	1005.950	1132.735	2110.158	51236.906
Total Demand	5171.597	7669.611	10424.60	8426.074	7581.289	3782.239	1809.829	1116.869	1005.950	1005.950	1132.735	2110.158	51236.906
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	82.716	130.905	155.005	132.129	128.946	57.971	30.326	21.881	22.465	19.999	17.757	20.596	820.698
Injection	0.000	0.000	0.000	0.000	0.000	7.612	13.752	13.480	6.792	5.899	13.480	8.908	69.923
Withdrawal	0.054	6.660	15.001	10.947	3.943	0.000	0.000	0.000	0.000	0.000	0.000	0.000	36.605
Total Fuel	82.770	137.565	170.005	143.077	132.890	65.584	44.078	35.361	29.257	25.898	31.237	29.504	927.226
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	150.000	155.000	68.041	15.841	0.000	25.061	0.000	413.943
LNG Lawrence	1.913	1.976	0.000	0.434	1.976	2.130	13.829	2.130	2.201	0.000	4.331	2.201	33.121
LNG Marshfld	0.835	0.863	1.213	0.780	0.863	0.990	8.645	0.990	1.023	0.000	2.013	1.023	19.238
LNG Spring	0.000	0.000	0.000	0.000	0.000	171.263	310.000	32.250	33.325	0.000	65.575	4.873	617.286
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	201.266	244.734	236.840	0.000	244.734	236.840	244.734	1409.148
Enbridge 16	0.000	0.000	0.000	0.000	0.000	357.840	369.768	357.840	84.712	0.000	357.840	0.000	1528.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	407.043	420.611	407.043	139.470	0.000	407.043	0.000	1781.210
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	148.397	181.634	187.689	187.689	181.634	132.278	1019.320
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	9.725	10.049	9.725	4.036	10.049	9.725	10.049	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.821	243.698	251.821	251.821	243.698	251.821	1494.679
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	249.421	241.376	241.000	0.000	241.376	249.421	1222.594
Total Inj	2.748	2.839	22.213	1.213	2.839	1300.257	2182.276	1781.567	961.117	694.293	1775.135	896.400	9622.898
Total Req	5257.114	7810.015	10616.82	8570.364	7717.018	5148.080	4036.183	2933.797	1996.324	1726.141	2939.107	3036.063	61787.030
Sources of Supply													
Beverly	0.000	20.068	196.274	96.609	20.506	0.000	0.000	0.000	0.000	0.000	0.000	0.000	333.458
Centerville	159.722	916.944	1249.638	966.094	677.122	14.027	167.826	0.000	0.000	0.000	0.000	1049.436	5200.808
Dawn	1276.554	2174.832	1804.683	1834.994	1570.624	1368.675	795.150	769.500	225.535	0.000	769.500	0.000	12590.046
Dracut	6.661	18.654	74.430	38.274	257.676	0.000	4.702	0.000	0.000	0.000	0.000	39.056	439.453
TGP Z4 313	545.712	563.902	0.000	50.315	364.227	542.682	793.487	725.592	714.119	469.970	738.733	810.282	6319.021
TGP Z4 200	382.460	399.705	399.705	361.024	389.026	355.771	203.839	18.723	0.000	0.000	39.207	291.023	2840.481

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	OCT 2025	Total
Sources of Supply													
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Inject	2.748	2.839	1.213	1.213	2.839	324.383	487.474	103.411	52.390	0.000	96.980	8.097	1083.588
LPG Inject	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
Millennium	453.127	468.231	468.231	422.918	468.231	0.000	0.000	0.000	468.231	0.000	0.000	0.000	2748.968
Niagara	298.274	318.845	318.845	287.989	301.569	260.237	217.777	185.130	191.301	191.301	185.130	249.893	3006.292
Ramapo	386.871	50.102	274.801	164.562	474.781	900.797	800.343	573.192	34.286	499.286	0.000	0.000	4159.021
Repsol 30	0.000	118.165	558.643	310.192	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	82.881	279.457	201.662	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1055.607	1136.073	1136.073	1026.131	1118.082	1059.516	513.195	507.548	258.072	513.195	1058.858	535.887	9918.236
TETCO M3	635.052	31.188	112.568	94.326	747.384	271.291	0.000	0.000	0.000	0.000	0.000	0.000	1891.810
Winter AGT	0.000	0.000	10.545	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	10.545
Winter TGP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	5202.786	6302.430	6906.105	5856.303	6392.067	5097.380	3983.793	2883.097	1943.934	1673.751	2888.407	2983.673	52113.728
Storage Withdrawals													
LNG Easton	12.514	21.299	171.777	85.862	35.089	15.330	15.841	15.330	15.841	15.841	15.330	15.841	435.894
LNG Lawrence	1.912	1.976	10.277	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	33.121
LNG Marshfld	0.835	0.863	8.835	0.780	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	19.238
LNG Spring	27.072	29.183	202.757	104.263	52.413	32.250	33.325	32.250	33.325	33.325	32.250	33.325	645.738
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	373.858	373.859	337.679	323.752	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1409.148
Enbridge 16	0.000	448.000	496.000	397.600	186.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1528.000
Enbridge 18	0.000	240.500	821.500	489.190	230.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1781.210
Nat Fuel FSS	11.994	163.006	310.000	275.850	258.470	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1019.320
TETCO FSS-1	0.000	5.632	31.680	23.938	2.110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	223.268	699.130	538.098	34.183	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1494.679
TGP FSMA	0.000	0.000	563.902	459.017	199.675	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	54.328	1507.585	3710.717	2714.061	1324.952	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9673.302
Total Supply	5257.114	7810.015	10616.82	8570.364	7717.018	5148.080	4036.183	2933.797	1996.324	1726.141	2939.107	3036.063	61787.030
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	OCT 2025	Total
Net Storage Inv. Adj.													
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	731.704	719.190	697.892	526.115	440.253	405.164	539.834	678.993	731.704	731.704	715.863	725.594	731.704
LNG Lawrence	11.628	11.628	11.628	1.351	0.000	0.000	0.000	11.628	11.628	11.628	9.427	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	7.622	6.599	7.622	7.622
LNG Spring	948.413	921.341	892.158	689.401	585.138	532.725	671.738	948.413	948.413	948.413	915.088	948.413	948.413
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1441.753	1067.895	694.036	356.357	32.605	233.871	478.605	715.445	715.445	960.179	1197.019	1441.753
Enbridge 16	1600.000	1600.000	1152.000	656.000	258.400	72.000	429.840	799.608	1157.448	1242.160	1242.160	1600.000	1600.000
Enbridge 18	1820.000	1820.000	1579.500	758.000	268.810	38.790	445.833	866.444	1273.487	1412.957	1412.957	1820.000	1820.000
Nat Fuel FSS	1100.000	1088.006	925.000	615.000	339.150	80.680	80.680	229.077	410.711	598.399	786.088	967.722	1100.000
TETCO FSS-1	63.360	63.360	57.728	26.048	2.110	0.000	9.725	19.775	29.500	33.536	43.585	53.311	63.360
TETCO SS-1	1588.950	1588.950	1365.682	666.552	128.454	94.271	94.271	346.092	589.790	841.611	1093.432	1337.129	1588.950
TGP FSMA	1222.594	1222.594	1222.594	658.692	199.675	0.000	0.000	249.421	490.797	731.797	731.797	973.173	1222.594
Total Inv	10641.52	10589.94	9085.202	5396.699	2683.851	1361.739	2611.296	4741.182	6472.048	7380.776	8022.679	9747.114	10641.528
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	Total
Forecast Demand													
Demand	5163.484	7662.742	10487.18	8488.493	7635.263	3854.712	1854.421	1143.335	1055.178	1055.178	1185.067	2164.520	51749.575
Total Demand	5163.484	7662.742	10487.18	8488.493	7635.263	3854.712	1854.421	1143.335	1055.178	1055.178	1185.067	2164.520	51749.575
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	80.631	130.551	154.258	131.098	119.007	39.375	18.810	22.299	20.839	20.856	13.893	21.473	773.092
Injection	0.000	0.000	0.000	0.000	0.000	4.638	13.771	13.480	10.244	5.894	13.480	9.158	70.666
Withdrawal	0.055	6.990	15.008	10.943	3.873	0.000	0.000	0.000	0.000	0.000	0.000	0.000	36.870
Total Fuel	80.687	137.542	169.267	142.041	122.880	44.013	32.581	35.779	31.084	26.750	27.373	30.631	880.628
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	150.000	155.000	97.914	15.841	0.000	25.061	0.000	443.816
LNG Lawrence	1.913	1.976	0.000	1.780	1.976	2.130	13.829	2.130	2.201	0.000	4.331	2.201	34.467
LNG Marshfld	0.835	0.863	1.213	0.780	0.863	0.990	8.645	0.990	1.023	0.000	2.013	1.023	19.238
LNG Spring	0.000	0.000	0.000	0.000	0.000	216.708	310.000	32.250	33.325	0.000	65.575	4.873	662.731
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	244.734	236.840	233.871	244.734	236.840	244.734	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	357.840	369.768	357.840	84.712	0.000	357.840	0.000	1528.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	407.043	420.611	407.043	139.735	0.000	407.043	0.000	1781.475
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	152.714	181.634	187.689	186.601	181.634	187.689	1077.960
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.712	10.049	9.725	10.049	10.049	9.725	10.049	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.821	243.698	251.821	251.821	243.698	251.821	1494.679
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	249.421	241.376	241.000	0.000	241.376	249.421	1222.594
Total Inj	2.748	2.839	22.213	2.559	2.839	1138.423	2186.593	1811.439	1201.266	693.206	1775.135	951.811	9791.072
Total Req	5246.919	7803.123	10678.66	8633.094	7760.983	5037.148	4073.594	2990.553	2287.528	1775.134	2987.574	3146.963	62421.275
Sources of Supply													
Beverly	0.000	20.068	200.911	102.008	21.180	0.000	0.000	0.000	0.000	0.000	0.000	0.000	344.167
Centerville	136.505	928.093	1262.211	979.086	688.849	16.466	969.243	6.620	0.000	0.000	592.676	1082.899	6662.648
Dawn	1288.227	2078.162	1807.882	1853.585	1603.689	769.500	795.150	769.500	225.802	0.000	769.500	0.000	11960.997
Dracut	6.958	143.362	76.589	40.867	270.158	615.051	6.999	0.000	0.000	0.000	0.000	101.206	1261.189
TGP Z4 313	545.712	384.340	0.000	140.189	453.915	543.256	799.332	739.139	731.928	487.779	749.713	812.031	6387.336
TGP Z4 200	383.017	399.705	399.705	361.024	389.692	357.100	210.784	18.101	0.000	0.000	46.235	296.978	2862.340

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	Total
Sources of Supply													
Hereford	0.000	0.000	0.000	0.000	0.000	0.211	0.000	0.000	0.000	0.000	0.000	0.000	0.211
LNG Inject	2.748	2.839	1.213	2.559	2.839	369.828	487.474	133.284	52.390	0.000	96.980	8.097	1160.251
LPG Inject	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
Millennium	0.000	468.231	468.231	422.918	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1359.380
Niagara	298.274	318.845	318.845	287.989	302.270	263.647	229.248	185.130	191.301	190.192	185.130	251.924	3022.796
Ramapo	913.761	45.676	250.488	140.825	970.874	903.435	0.000	591.439	531.578	531.578	0.000	0.000	4879.654
Repsol 30	0.000	30.297	581.221	375.482	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	49.301	314.357	200.342	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	981.072	1136.073	1136.073	1026.131	0.000	3.744	522.975	496.640	502.139	513.195	496.640	541.439	7356.120
TETCO M3	592.689	30.021	98.439	77.750	1846.502	1144.211	0.000	0.000	0.000	0.000	0.000	0.000	3789.611
Winter AGT	0.000	0.000	11.503	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	11.503
Winter TGP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	5148.963	6035.013	6948.669	6010.755	6549.969	4986.448	4021.204	2939.853	2235.138	1722.744	2936.874	3094.573	52630.203
Storage Withdrawals													
LNG Easton	12.514	19.143	178.009	89.116	35.681	15.330	15.841	15.330	15.841	15.841	15.330	15.841	443.816
LNG Lawrence	1.912	1.976	11.623	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	34.467
LNG Marshfld	0.835	0.863	8.835	0.780	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	19.238
LNG Spring	27.072	29.827	213.483	108.614	53.685	32.250	33.325	32.250	33.325	33.325	32.250	33.325	662.731
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	43.293	373.859	373.859	337.679	313.063	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	0.000	448.000	496.000	397.600	186.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1528.000
Enbridge 18	0.000	267.000	821.500	462.955	230.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1781.475
Nat Fuel FSS	12.329	242.671	310.000	269.210	243.750	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1077.960
TETCO FSS-1	0.000	5.632	31.680	24.642	1.406	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	199.576	700.103	560.816	34.183	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1494.679
TGP FSMA	0.000	179.562	563.902	369.142	109.987	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	97.956	1768.110	3729.994	2622.339	1211.014	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9791.072
Total Supply	5246.919	7803.123	10678.66	8633.094	7760.983	5037.148	4073.594	2990.553	2287.528	1775.134	2987.574	3146.963	62421.275
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	Total
Net Storage Inv. Adj.													
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	709.753	697.239	678.096	500.087	410.972	375.291	509.961	649.120	731.704	731.704	715.863	725.594	709.753
LNG Lawrence	11.628	11.628	11.628	0.005	0.000	0.000	0.000	11.628	11.628	11.628	9.427	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	7.622	6.599	7.622	7.622
LNG Spring	919.961	892.889	863.062	649.579	540.965	487.280	671.738	948.413	948.413	948.413	915.088	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1398.460	1024.601	650.742	313.063	0.000	0.000	244.734	481.574	715.445	960.179	1197.019	1441.753
Enbridge 16	1600.000	1600.000	1152.000	656.000	258.400	72.000	429.840	799.608	1157.448	1242.160	1242.160	1600.000	1600.000
Enbridge 18	1820.000	1820.000	1553.000	731.500	268.545	38.525	445.568	866.179	1273.222	1412.957	1412.957	1820.000	1820.000
Nat Fuel FSS	1100.000	1087.671	845.000	535.000	265.790	22.040	22.040	174.754	356.388	544.076	730.677	912.311	1100.000
TETCO FSS-1	63.360	63.360	57.728	26.048	1.406	0.000	3.712	13.761	23.487	33.536	43.585	53.311	63.360
TETCO SS-1	1588.950	1588.950	1389.374	689.271	128.454	94.271	94.271	346.092	589.790	841.611	1093.432	1337.129	1588.950
TGP FSMA	1222.594	1222.594	1043.032	479.129	109.987	0.000	0.000	249.421	490.797	731.797	731.797	973.173	1222.594
Total Inv	10591.12	10495.91	8730.646	5022.865	2403.086	1194.911	2282.634	4416.837	6177.576	7326.453	7967.268	9691.703	10591.124
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements | Units: MDT

	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	OCT 2027	Total
Forecast Demand													
Demand	5260.463	7817.601	10671.72	8662.129	7789.270	3991.145	1938.476	1196.500	1115.008	1115.008	1248.191	2210.065	53015.585
Total Demand	5260.463	7817.601	10671.72	8662.129	7789.270	3991.145	1938.476	1196.500	1115.008	1115.008	1248.191	2210.065	53015.585
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	84.447	132.396	156.223	134.078	120.392	40.084	19.418	23.218	21.930	17.683	19.243	32.342	801.453
Injection	0.000	0.000	0.000	0.000	0.000	4.638	13.364	10.326	10.496	9.158	13.480	9.120	70.582
Withdrawal	0.066	7.346	15.068	10.709	3.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	36.787
Total Fuel	84.513	139.742	171.291	144.787	123.991	44.722	32.782	33.543	32.425	26.841	32.723	41.462	908.823
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	150.000	155.000	150.000	15.841	0.000	27.990	0.000	498.831
LNG Lawrence	1.913	1.976	2.785	1.785	1.976	2.130	13.829	2.130	0.000	0.000	6.532	2.201	37.256
LNG Marshfld	0.835	0.863	1.213	0.780	0.863	0.990	8.645	0.990	0.000	0.000	3.036	1.023	19.238
LNG Spring	0.000	0.000	0.000	0.000	0.000	267.677	310.000	32.250	33.325	0.000	65.575	4.873	713.700
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	1.000	20.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.337	0.337
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	233.871	236.840	244.734	244.734	236.840	244.734	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	357.840	369.768	357.840	81.832	0.000	357.840	0.000	1525.120
Enbridge 18	0.000	0.000	0.000	0.000	0.000	407.043	420.611	407.043	139.735	0.000	407.043	0.000	1781.475
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	145.379	181.634	187.689	187.689	181.634	179.276	1063.300
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.712	10.049	9.725	10.049	10.049	9.725	10.049	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.821	243.698	251.821	251.821	243.698	251.821	1494.679
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	232.954	0.000	249.421	249.421	241.376	249.421	1222.594
Total Inj	2.748	2.839	4.998	22.565	2.839	1189.392	2151.927	1622.150	1214.448	943.715	1781.288	943.736	9882.643
Total Req	5347.724	7960.182	10848.01	8829.481	7916.099	5225.259	4123.184	2852.192	2361.881	2085.564	3062.203	3195.263	63807.050
Sources of Supply													
Beverly	0.000	22.296	220.587	117.660	26.783	0.000	0.000	0.000	0.000	0.000	0.000	0.000	387.326
Centerville	715.299	946.524	1296.391	1024.828	734.385	24.566	1013.192	6.578	0.000	0.000	0.000	0.000	5761.764
Dawn	1315.432	2135.888	1807.940	1882.381	1643.238	769.500	795.150	769.500	222.904	0.000	769.500	0.000	12111.434
Dracut	8.258	140.589	89.253	45.854	298.747	660.399	13.190	0.000	0.000	0.000	0.000	98.526	1354.814
TGP Z4 313	545.712	275.198	0.233	195.286	507.728	543.966	788.474	511.485	762.471	762.471	762.423	814.148	6469.595
TGP Z4 200	383.775	399.705	399.705	361.024	390.707	358.896	223.251	23.056	0.000	0.000	55.954	303.825	2899.897

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	OCT 2027	Total
Sources of Supply													
Hereford	0.000	0.000	0.000	0.000	0.000	1.429	0.000	0.000	0.000	0.000	0.000	0.000	1.429
LNG Inject	2.748	2.839	3.998	2.565	2.839	420.797	487.474	185.370	49.166	0.000	103.133	8.097	1269.025
LPG Inject	0.000	0.000	1.000	20.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.337	21.337
Millennium	453.127	468.231	468.231	422.918	0.000	0.000	0.000	0.000	0.000	0.000	0.000	136.066	1948.572
Niagara	298.274	318.845	318.845	287.989	308.560	268.667	233.071	185.130	191.301	191.301	185.130	254.119	3041.233
Ramapo	394.263	58.091	289.970	189.234	970.874	906.279	14.855	623.732	570.454	0.000	0.000	24.392	4042.144
Repsol 30	0.000	46.429	589.286	351.285	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	56.574	288.801	218.626	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1061.877	1136.073	1136.073	1026.131	0.000	3.744	502.139	496.640	513.195	1079.402	1135.362	1503.364	9593.999
TETCO M3	68.634	33.032	123.378	113.916	1901.541	1216.315	0.000	0.000	0.000	0.000	0.000	0.000	3456.816
Winter AGT	0.000	0.000	16.951	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	16.951
Winter TGP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	5247.399	6040.313	7050.641	6259.696	6785.401	5174.559	4070.794	2801.492	2309.491	2033.174	3011.503	3142.873	53927.336
Storage Withdrawals													
LNG Easton	12.514	23.942	203.103	106.797	40.192	15.330	15.841	15.330	15.841	15.841	15.330	15.841	495.902
LNG Lawrence	1.912	1.976	14.413	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	37.257
LNG Marshfld	0.835	0.863	8.835	0.780	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	19.238
LNG Spring	27.072	32.087	245.239	122.492	56.759	32.250	33.325	32.250	33.325	33.325	32.250	33.325	713.700
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.337	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.337
DTI GSS TET	43.293	373.859	373.859	337.679	313.063	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	0.000	448.000	496.000	397.600	183.520	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1525.120
Enbridge 18	0.000	267.000	821.500	462.955	230.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1781.475
Nat Fuel FSS	14.699	220.301	310.000	270.870	247.430	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1063.300
TETCO FSS-1	0.000	6.336	32.032	24.291	0.701	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	256.799	707.389	530.491	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1494.679
TGP FSMA	0.000	288.705	563.669	314.045	56.175	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	100.325	1919.868	3797.377	2569.784	1130.699	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9879.714
Total Supply	5347.724	7960.182	10848.01	8829.481	7916.099	5225.259	4123.184	2852.192	2361.881	2085.564	3062.203	3195.263	63807.050
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

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Natural Gas Supply VS. Requirements Units: MDT

	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	OCT 2027	Total
Net Storage Inv. Adj.													
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	709.753	697.239	673.297	470.194	363.397	323.205	457.875	597.034	731.704	731.704	715.863	728.523	709.753
LNG Lawrence	11.628	11.628	11.628	0.000	0.000	0.000	0.000	11.628	11.628	9.427	7.226	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	6.599	5.576	7.622	7.622
LNG Spring	919.961	892.889	860.801	615.562	493.070	436.311	671.738	948.413	948.413	948.413	915.088	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	50.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.385	21.385	21.385	21.385	21.385	21.385	21.385	21.385	21.385	21.722
DTI GSS TET	1441.753	1398.460	1024.601	650.742	313.063	0.000	0.000	233.871	470.710	715.445	960.179	1197.019	1441.753
Enbridge 16	1600.000	1600.000	1152.000	656.000	258.400	74.880	432.720	802.488	1160.328	1242.160	1242.160	1600.000	1600.000
Enbridge 18	1820.000	1820.000	1553.000	731.500	268.545	38.525	445.568	866.179	1273.222	1412.957	1412.957	1820.000	1820.000
Nat Fuel FSS	1100.000	1085.301	865.000	555.000	284.130	36.700	36.700	182.079	363.713	551.401	739.090	920.724	1100.000
TETCO FSS-1	63.360	63.360	57.024	24.992	0.701	0.000	3.712	13.761	23.487	33.536	43.585	53.311	63.360
TETCO SS-1	1588.950	1588.950	1332.151	624.762	94.271	94.271	94.271	346.092	589.790	841.611	1093.432	1337.129	1588.950
TGP FSMA	1222.594	1222.594	933.889	370.220	56.175	0.000	0.000	232.954	232.954	482.376	731.797	973.173	1222.594
Total Inv	10591.12	10493.54	8576.518	4784.139	2236.919	1109.059	2247.751	4347.288	5918.737	7080.795	7972.120	9702.708	10591.124
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2027	DEC 2027	JAN 2028	FEB 2028	MAR 2028	APR 2028	MAY 2028	JUN 2028	JUL 2028	AUG 2028	SEP 2028	OCT 2028	Total
Forecast Demand													
Demand	5348.265	7957.712	10823.40	8799.985	7914.792	4091.370	2000.233	1234.413	1154.533	1154.533	1289.753	2244.580	54013.575
Total Demand	5348.265	7957.712	10823.40	8799.985	7914.792	4091.370	2000.233	1234.413	1154.533	1154.533	1289.753	2244.580	54013.575
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	75.211	134.022	157.172	137.652	126.015	48.230	19.489	23.423	22.609	18.186	19.773	32.917	814.697
Injection	0.000	0.000	0.000	0.000	0.000	8.148	11.634	8.335	10.451	9.158	13.480	9.158	70.366
Withdrawal	0.079	7.090	15.044	11.065	3.497	0.000	0.000	0.000	0.000	0.000	0.000	0.000	36.776
Total Fuel	75.290	141.112	172.217	148.717	129.512	56.378	31.124	31.758	33.060	27.344	33.253	42.075	921.839
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	150.000	155.000	150.000	15.841	0.000	25.061	0.000	495.902
LNG Lawrence	1.913	1.976	2.785	1.849	1.976	2.130	13.829	2.130	2.201	0.000	4.331	1.852	36.971
LNG Marshfld	0.835	0.863	1.213	0.807	0.863	0.990	8.645	0.990	1.023	0.000	2.013	0.794	19.037
LNG Spring	0.000	0.000	0.000	0.000	0.000	300.000	310.000	32.250	33.325	0.000	65.575	4.873	746.023
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	20.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	3.284	3.284
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	236.840	118.420	101.441	244.734	244.734	236.840	244.734	1427.743
Enbridge 16	0.000	0.000	0.000	0.000	0.000	357.840	369.768	357.840	81.832	0.000	357.840	0.000	1525.120
Enbridge 18	0.000	0.000	0.000	0.000	0.000	407.043	420.611	407.043	132.315	0.000	407.043	0.000	1774.055
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	3.557	140.739	181.634	187.689	187.689	181.634	187.689	1070.630
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	9.725	6.159	7.602	10.049	10.049	9.725	10.049	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.821	243.698	251.821	251.821	243.698	251.821	1494.679
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	232.954	0.000	249.421	249.421	241.376	249.421	1222.594
Total Inj	2.748	2.839	23.998	2.656	3.839	1468.125	2027.946	1484.628	1210.252	943.715	1775.135	954.518	9900.398
Total Req	5426.303	8101.663	11019.62	8951.358	8048.143	5615.873	4059.302	2750.799	2397.844	2125.592	3098.142	3241.173	64835.812
Sources of Supply													
Beverly	0.000	26.142	236.359	104.635	34.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	401.136
Centerville	185.293	1013.693	1321.957	1044.731	1334.798	386.061	1041.549	7.296	0.000	0.000	0.000	0.000	6335.377
Dawn	1343.734	2196.003	1817.586	1942.627	1687.540	769.500	795.150	769.500	215.440	0.000	769.500	0.000	12306.580
Dracut	9.801	147.113	98.975	40.267	324.579	698.744	20.855	0.000	0.000	0.000	0.000	112.835	1453.169
TGP Z4 313	545.712	2.575	75.405	354.753	563.902	544.501	792.838	523.340	779.026	779.026	771.520	815.361	6547.959
TGP Z4 200	384.398	399.705	399.705	373.917	399.705	360.280	232.373	28.683	0.000	0.000	63.801	309.262	2951.830

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2027	DEC 2027	JAN 2028	FEB 2028	MAR 2028	APR 2028	MAY 2028	JUN 2028	JUL 2028	AUG 2028	SEP 2028	OCT 2028	Total
Sources of Supply													
Hereford	0.000	0.000	0.000	0.000	0.000	2.385	0.000	0.000	0.000	0.000	0.000	0.000	2.385
LNG Inject	2.748	2.839	3.998	2.656	2.839	453.120	487.474	185.370	52.390	0.000	96.980	7.519	1297.933
LPG Inject	0.000	0.000	20.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	3.284	24.284
Millennium	0.000	468.231	468.231	438.022	453.421	0.000	0.000	0.000	0.000	0.000	0.000	143.423	1971.328
Niagara	298.274	318.845	318.845	298.274	312.080	275.224	236.105	185.130	191.301	191.301	185.130	256.266	3066.776
Ramapo	916.013	70.736	300.952	176.245	335.771	907.645	19.844	644.072	594.103	0.000	0.000	26.583	3991.964
Repsol 30	0.000	47.922	617.417	321.662	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	70.500	282.000	211.500	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	0.000	1136.073	1136.073	1062.778	1136.073	1153.750	380.725	356.708	513.195	1102.875	1160.511	1514.249	10653.009
TETCO M3	1669.741	42.656	127.082	110.278	392.269	13.963	0.000	0.000	0.000	0.000	0.000	0.000	2355.990
Winter AGT	0.000	0.000	21.187	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.187
Winter TGP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	5355.715	5943.033	7245.771	6482.346	6977.978	5565.173	4006.912	2700.099	2345.454	2073.202	3047.442	3188.783	54931.907
Storage Withdrawals													
LNG Easton	12.514	25.786	222.558	84.858	43.761	15.330	15.841	15.330	15.841	15.841	15.330	15.841	498.831
LNG Lawrence	1.912	1.976	14.413	1.849	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	37.320
LNG Marshfld	0.835	0.863	8.835	0.807	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	19.266
LNG Spring	27.072	36.960	277.573	114.739	59.628	32.250	33.325	32.250	33.325	33.325	32.250	33.325	746.023
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	3.284	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	3.284
DTI GSS TET	10.666	373.859	373.859	349.739	319.621	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1427.743
Enbridge 16	0.000	448.000	496.000	406.400	174.720	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1525.120
Enbridge 18	0.000	240.500	821.500	489.455	222.600	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1774.055
Nat Fuel FSS	17.590	217.410	310.000	280.040	245.590	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1070.630
TETCO FSS-1	0.000	4.224	31.680	26.050	1.406	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	247.724	704.649	542.305	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1494.679
TGP FSMA	0.000	561.328	488.498	172.769	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	70.588	2158.631	3773.849	2469.012	1070.165	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9903.904
Total Supply	5426.303	8101.663	11019.62	8951.358	8048.143	5615.873	4059.302	2750.799	2397.844	2125.592	3098.142	3241.173	64835.812
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2027	DEC 2027	JAN 2028	FEB 2028	MAR 2028	APR 2028	MAY 2028	JUN 2028	JUL 2028	AUG 2028	SEP 2028	OCT 2028	Total
Net Storage Inv. Adj.													
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	712.682	700.168	674.382	451.825	366.966	323.205	457.875	597.034	731.704	731.704	715.863	725.594	712.682
LNG Lawrence	11.628	11.628	11.628	0.000	0.000	0.000	0.000	11.628	11.628	11.628	9.427	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	7.622	6.599	7.622	7.622
LNG Spring	919.961	892.889	855.928	578.355	463.616	403.988	671.738	948.413	948.413	948.413	915.088	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	69.749	69.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	18.438	18.438	18.438	18.438	18.438	18.438	18.438	18.438	18.438	21.722
DTI GSS TET	1441.753	1431.087	1057.228	683.369	333.630	14.010	250.849	369.269	470.710	715.445	960.179	1197.019	1441.753
Enbridge 16	1600.000	1600.000	1152.000	656.000	249.600	74.880	432.720	802.488	1160.328	1242.160	1242.160	1600.000	1600.000
Enbridge 18	1820.000	1820.000	1579.500	758.000	268.545	45.945	452.988	873.599	1280.642	1412.957	1412.957	1820.000	1820.000
Nat Fuel FSS	1100.000	1082.410	865.000	555.000	274.960	29.370	32.927	173.666	355.300	542.989	730.677	912.311	1100.000
TETCO FSS-1	63.360	63.360	59.136	27.456	1.406	0.000	9.725	15.885	23.487	33.536	43.585	53.311	63.360
TETCO SS-1	1588.950	1588.950	1341.226	636.577	94.271	94.271	94.271	346.092	589.790	841.611	1093.432	1337.129	1588.950
TGP FSMA	1222.594	1222.594	661.266	172.769	0.000	0.000	0.000	232.954	232.954	482.376	731.797	973.173	1222.594
Total Inv	10594.05	10526.21	8370.421	4620.570	2154.215	1087.889	2505.314	4480.870	5914.798	7072.659	7963.984	9688.419	10594.053
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	2023	2024	2025	2026	2027	Total
Forecast Demand						
Demand	51730.85	51236.90	51749.57	53015.58	54013.57	261746.49
Total Demand	51730.85	51236.90	51749.57	53015.58	54013.57	261746.49
Forecast Rt Mrktr Imbalance						
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed						
Transport	831.303	820.698	773.092	801.453	814.697	4041.244
Injection	68.973	69.923	70.666	70.582	70.366	350.510
Withdrawal	35.526	36.605	36.870	36.787	36.776	182.564
Total Fuel	935.803	927.226	880.628	908.823	921.839	4574.318
Storage Injections						
LNG Easton	420.207	413.943	443.816	498.831	495.902	2272.699
LNG Lawrence	33.829	33.121	34.467	37.256	36.971	175.645
LNG Marshfld	19.266	19.238	19.238	19.238	19.037	96.017
LNG Spring	634.396	617.286	662.731	713.700	746.023	3374.135
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	21.000	21.000	21.000	21.000	21.000	105.000
LPG NHampton	0.000	0.000	0.000	0.337	3.284	3.621
DTI GSS TET	1418.446	1409.148	1441.753	1441.753	1427.743	7138.843
Enbridge 16	1429.600	1528.000	1528.000	1525.120	1525.120	7535.840
Enbridge 18	1705.299	1781.210	1781.475	1781.475	1774.055	8823.514
Nat Fuel FSS	1011.990	1019.320	1077.960	1063.300	1070.630	5243.200
TETCO FSS-1	63.360	63.360	63.360	63.360	63.360	316.800
TETCO SS-1	1494.679	1494.679	1494.679	1494.679	1494.679	7473.393
TGP FSMA	1222.594	1222.594	1222.594	1222.594	1222.594	6112.970
Total Inj	9474.666	9622.898	9791.072	9882.643	9900.398	48671.677
Total Req	62141.31	61787.03	62421.27	63807.05	64835.81	314992.48

	2023	2024	2025	2026	2027	Total
Sources of Supply						
Beverly	345.947	333.458	344.167	387.326	401.136	1812.035
Centerville	4153.777	5200.808	6662.648	5761.764	6335.377	28114.375
Dawn	12731.18	12590.04	11960.99	12111.43	12306.58	61700.242
Dracut	391.207	439.453	1261.189	1354.814	1453.169	4899.832
TGP Z4 313	6340.589	6319.021	6387.336	6469.595	6547.959	32064.500
TGP Z4 200	2855.814	2840.481	2862.340	2899.897	2951.830	14410.362

Natural Gas Supply VS. Requirements

Units: MDT

	2023	2024	2025	2026	2027	Total
Sources of Supply						
Hereford	0.000	0.000	0.211	1.429	2.385	4.025
LNG Inject	1107.699	1083.588	1160.251	1269.025	1297.933	5918.495
LPG Inject	21.000	21.000	21.000	21.337	24.284	108.621
Millennium	3188.328	2748.968	1359.380	1948.572	1971.328	11216.576
Niagara	3016.853	3006.292	3022.796	3041.233	3066.776	15153.949
Ramapo	3788.827	4159.021	4879.654	4042.144	3991.964	20861.610
Repsol 30	987.000	987.000	987.000	987.000	987.000	4935.000
Repsol 40	564.000	564.000	564.000	564.000	564.000	2820.000
TETCO M2	10143.25	9918.236	7356.120	9593.999	10653.00	47664.616
TETCO M3	3020.491	1891.810	3789.611	3456.816	2355.990	14514.717
Winter AGT	10.685	10.545	11.503	16.951	21.187	70.871
Winter TGP	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	52666.65	52113.72	52630.20	53927.33	54931.90	266269.82
Storage Withdrawals						
LNG Easton	420.207	435.894	443.816	495.902	498.831	2294.650
LNG Lawrence	33.829	33.121	34.467	37.257	37.320	175.993
LNG Marshfld	19.266	19.238	19.238	19.238	19.266	96.246
LNG Spring	634.396	645.738	662.731	713.700	746.023	3402.587
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	21.000	21.000	21.000	21.000	21.000	105.000
LPG NHampton	0.000	0.000	0.000	0.337	3.284	3.621
DTI GSS TET	1418.446	1409.148	1441.753	1441.753	1427.743	7138.843
Enbridge 16	1429.600	1528.000	1528.000	1525.120	1525.120	7535.840
Enbridge 18	1705.299	1781.210	1781.475	1781.475	1774.055	8823.514
Nat Fuel FSS	1011.990	1019.320	1077.960	1063.300	1070.630	5243.200
TETCO FSS-1	63.360	63.360	63.360	63.360	63.360	316.800
TETCO SS-1	1494.679	1494.679	1494.679	1494.679	1494.679	7473.393
TGP FSMA	1222.594	1222.594	1222.594	1222.594	1222.594	6112.970
Total With	9474.666	9673.302	9791.072	9879.714	9903.904	48722.658
Total Supply	62141.31	61787.03	62421.27	63807.05	64835.81	314992.48
Net Storage Inv. Adj.						
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	2023	2024	2025	2026	2027	Total
Net Storage Inv. Adj.						
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000
Start of Year Inventory						
LNG Easton	731.704	731.704	709.753	709.753	712.682	731.704
LNG Lawrence	11.628	11.628	11.628	11.628	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	7.622	7.622	7.622
LNG Spring	948.413	948.413	919.961	919.961	919.961	948.413
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1441.753	1441.753	1441.753	1441.753	1441.753
Enbridge 16	1600.000	1600.000	1600.000	1600.000	1600.000	1600.000
Enbridge 18	1820.000	1820.000	1820.000	1820.000	1820.000	1820.000
Nat Fuel FSS	1100.000	1100.000	1100.000	1100.000	1100.000	1100.000
TETCO FSS-1	63.360	63.360	63.360	63.360	63.360	63.360
TETCO SS-1	1588.950	1588.950	1588.950	1588.950	1588.950	1588.950
TGP FSMA	1222.594	1222.594	1222.594	1222.594	1222.594	1222.594
Total Inv	10641.52	10641.52	10591.12	10591.12	10594.05	10641.528
Unsupplied Demand						
Demand	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000