EPCOR Natural Gas Limited Partnership

2024-2028 Aylmer Gas Supply Plan

Aylmer

EB-2024-0139

Contents

1. Introduction

On October 25, 2018, the Ontario Energy Board ("Board") issued its Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans ("Framework") which set out a new requirement for all rate-regulated natural gas distributors in the Province of Ontario to file five year gas plans in January 2019. EPCOR Natural Gas Limited Partnership ("EPCOR" or "ENGLP") filed the Gas Supply Plan for the period 2019-2024 as part of the utility's cost of service application, in proceeding EB-2018-0336. In the phase 1 decision, the OEB approved the settlement proposal between the applicant and the intervenors in its entirety, including EPCOR's five-year Supply Plan, including the resulting cost consequences of the plan.

EPCOR has developed the following five-year Aylmer Gas Supply Plan ("Supply Plan") in accordance with the criteria and guiding principles of (i) cost-effectiveness, (ii) reliability and security of supply and (iii) public policy, as defined in the Framework.

The guiding Principles for the Assessment of Gas Supply Plans are defined as follows:

i. **Cost-effectiveness** – The gas supply plan will be cost-effective. Cost-effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner.

ii. **Reliability and security of supply** – The gas supply plan will ensure the reliable and secure supply of gas. Reliability and security of supply is achieved by ensuring gas supply to various receipt points to meet planned peak day and seasonal gas delivery requirements.

iii. **Public policy** – The gas supply plan will be developed to ensure that it supports and is aligned with public policy where appropriate.

To satisfy the Framework requirements, EPCOR has developed a demand forecast that reflects its expected annual load profile over the next five year rate period starting January 2024. The demand forecast was used as an input in determining the appropriate mix between supply obtained from the Enbridge system and local production.[1] To reliably meet forecasted Peak Day, seasonal, and annual demand, the supply strategy relies on the procurement of gas supply from local production as well as Enbridge.

Applying the Framework's guiding principles of cost-effectiveness and reliability and security of supply, any incremental local gas supply will be assessed against the landed costs of natural gas supply alternatives to ensure this supply will be competitive with any alternative supply source for EPCOR's rate payer. This approach ensures that cost-effectiveness is balanced against reliability and security of supply, which considers flexibility and diversity in commodity procurement. The Supply Plan reflects the notion that cost-effectiveness is not paramount to reliability, or vice versa, rather the two principles are assessed together and the final supply option is a balance of the two principles to ensure that customers receive reliable supply which optimizes the cost-reliability function.

The objective of the Supply Plan is to develop a right-sized portfolio of natural gas supply assets that ensures consumers receive a cost-effective, reliable and secure natural gas supply in a manner that is consistent with public policy. The portfolio is designed to strike a balance between these guiding principles, which are consistent with the Board's legislated mandate to protect the interest of consumers with respect to prices, reliability, and the quality of gas service.

The Framework requires that, where appropriate, the Supply Plan supports and is aligned with public policy objectives. This includes the Federal Carbon Pricing Program, Community Expansion, Minister of Energy Letter of Direction, and Canada Green Homes Grant.

The Supply Plan is intended to provide strategic direction that will guide EPCOR's

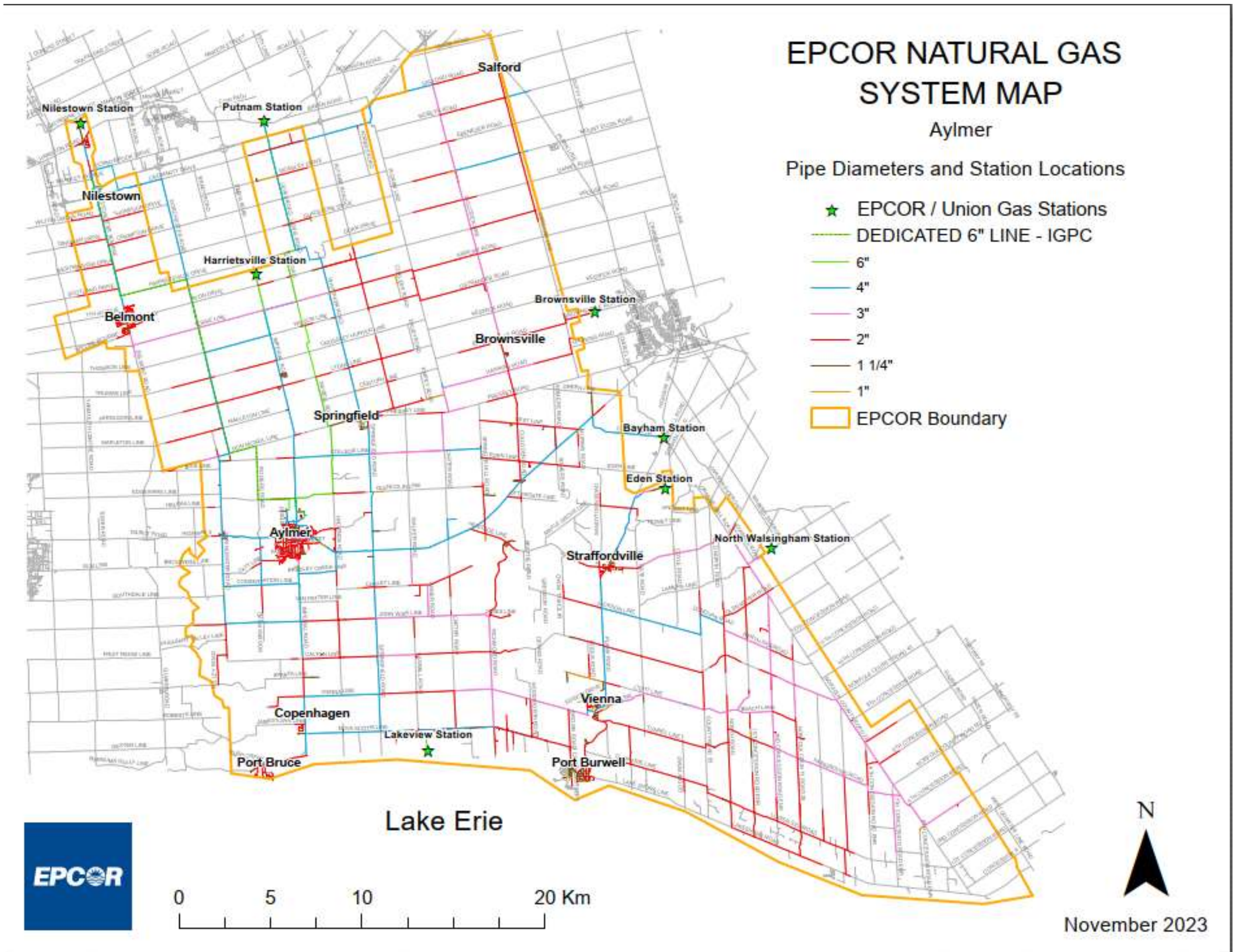
1 Local production has been described in detail through EPCOR's QRAM and other proceedings. Local production refers to gas produced within EPCOR's franchise area or adjacent Lake Erie, i.e., onshore well gas, lake gas, or onshore renewable natural gas.

ongoing decisions related to its natural gas portfolio such that the utility is able to meet Peak Day, seasonal, and annual demand throughout the winter and summer periods for General Service Customers and Contract Customers in a cost-effective manner. The plan does not commit EPCOR to procuring a set volume and/or source of natural gas, but rather provides a roadmap that is sufficiently flexible, such that reliable and cost-effective natural gas commodity and storage assets can still be procured in the event of changing or unexpected demand, consumption patterns, weather, or market forces.

EPCOR is presenting this five-year Plan, including upcoming decisions in the Supply Plan, with the aim of transparency and to enable meaningful consideration by the OEB. As the OEB pointed out in the Framework, “The responsibility for delivering reliable supply to customers in a prudent manner remains with the distributors. Distributors manage and execute their plans and adjust their activities to address changes to demand and supply conditions.”

1.1.Summary of Service Area

The map below provides a summary of EPCOR’s service territory which is current as of November 2023. There are no major changes compared to the 2023 Annual Update.


EPCOR NATURAL GAS SYSTEM MAP
Aylmer
Pipe Diameters and Station Locations
EPCOR / Union Gas Stations
DEDICATED 6" LINE - IGPC
6"
4"
3"
2"
1 1/4"
1"
EPCOR Boundary
Nilestown Station
Putnam Station
Salford
Nilestown
Harrietsville Station
Belmont
Brownsville Station
Brownsville
Springfield
Bayham Station
Eden Station
Aylmer
North Walsingham Station
Straffordville
Vienna
Copenhagen
Lakeview Station
Port Bruce
Port Burwell
Lake Erie
EPCOR
0
5
10
20 Km
N
November 2023

1.2. Significant Changes

No significant change is introduced in this Supply Plan.

2. Demand Forecast

To develop a natural gas supply portfolio, EPCOR first constructed a demand forecast. The demand forecast for this Supply Plan is based on the values provided by Elenchus Research Associates Inc. ("Elenchus") in its Weather Normalization and Distributions System Load Forecast (EB-2018-0336, Exhibit 3, Tab 2, Schedule 1). This analysis was updated by Power Advisory LLC ("Power Advisory") on May 28, 2024 for purposes of this gas supply plan. The forecast methodology can be found at the end of this section.

The utility will service three main classes of customers: General Service, Seasonal and Contract customers. These customers fit under six rate classes that include:

- **General Service Customers:** Rate 1 (General Service Rate) and Rate 4 (General Service Peaking),
- **Contract Customers:** Rate 3 (Special Large Volume Contract Rate), Rate 5 (Interruptible Peaking Contract Rate) and Rate 6 (Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility), and
- **Seasonal Customers:** Rate 2.

2.1. General Service Customers

General Service customers (residential, commercial, and industrial) are forecasted to make up approximately 30% of EPCOR's demand profile in 2024.

Residential customers comprise the majority (64%) of the General Service demand profile. While the residential segment is expected to have the highest growth in terms of customer numbers (from 9,318 to 9,448), weather normalized demand is expected to remain relatively flat in 2024 compared to 2023.

Commercial customers make up approximately 20.18% of the General Service demand profile. In 2024, 585 customers are forecasted to be under this segment. Both customer segments have flat, non-weather dependent demand requirements during the summer period (April to October), and heat-sensitive demand during the winter period (November to March). Industrial customers have an interruptible (Rate 4) and non-interruptible (Rate 1) component and make up approximately 15.85% of the General Service demand profile. There are 80 non-interruptible and 45 interruptible industrial customers in the EPCOR natural gas system forecasted for 2024.

2.2. Contract Customers

Contract customers are forecasted to make up approximately 70% of EPCOR's demand profile in 2024. There are currently 9 customers under this classification, with one Rate 3 contract customer added in 2024, which is expected to increase the demand for that customer group significantly. At this time, Contract Customers contract for their own natural gas supply. Contract customer Rates 3 and 5 have an interruptible component and on average make up approximately 4.54% of EPCOR's demand profile by volume and is expected to increase to 4.89% by 2028.

2.3. Seasonal Customers

Seasonal customer are forecasted to make up the remaining 0.82% of EPCOR's demand profile in 2024. There are 50 customers under this rate class and that consist mainly of tobacco framing and curing customers (non-interruptible).

The following tables provide EPCOR's Customer Connection Forecast and Annual Customer Service Demand Forecast by Rate Class. The forecasted values are provided by Elenchus in their Weather Normalization and Distributions System Load Forecast (EB-2018-0336, Exhibit 3, Tab 2, Schedule 1) and updated by Power Advisory for purposes of this Supply Plan. The updated Power Advisory report can be found in Appendix E.

Table 2-1 - Forecast of Customer Connections

	2023 Actual	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
R1 Residential	9,318	9,448	9,578	9,708	9,838	9,968
R1 Industrial	79	80	81	83	84	86
R1 Commercial	580	585	590	595	600	605
R2 Seasonal	51	50	50	50	50	50
R3	4	5	5	5	5	5
R4	43	45	46	48	49	51
R5	4	4	4	4	4	4
R6	1	1	1	1	1	1
Total	10,080	10,218	10,355	10,494	10,631	10,770

Table 2-2 - Forecast Annual Customer Service Demand, by Rate Class

	2023 Actual	2023 Normalized	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
R1 Residential	19,043,524	19,394,143	19,778,416	20,165,775	20,556,215	20,949,733	19,043,524
R1 Industrial	2,654,845	2,579,897	2,686,373	2,795,837	2,908,361	3,024,023	2,654,845
R1 Commercial	5,659,391	6,119,454	6,193,869	6,268,637	6,343,760	6,419,235	5,659,391
R2 Seasonal	869,131	832,281	832,281	832,281	832,281	832,281	869,131
R3	1,389,910	3,943,038	4,518,036	4,495,600	4,475,300	4,456,801	1,389,910
R4	2,227,329	2,023,938	2,334,616	2,408,833	2,485,410	2,564,421	2,227,329
R5	980,160	647,586	647,586	647,586	647,586	647,586	980,160
R6	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852
Total	98,170,143	100,886,188	102,337,027	102,960,400	103,594,765	104,239,931	98,170,143

2.4. Methodology

The forecasted annual customer service demand for R1 Residential, R1 Commercial, R1 Industrial and R3 rate classes were determined through multivariate regressions. Consumption of the three R1 rate classes were forecasted using a base load and excess consumption methodology wherein average monthly consumption per customer was first calculated for each class. The amounts were then reduced by the base load consumption, which is considered the average consumption in the summer months of July and August. The remaining consumption is considered the weather-sensitive load (or “excess” load).

The excess load was regressed by the actual heating degree days in each month to determine the impact of cold weather on average consumption. A time-series (Prais-Winsten) regression was used to determine the coefficient, consistent with the methodology used in prior NRG throughput forecasts. Actual heating degree days were then multiplied by the coefficients and base load consumption was added back to determine the average predicted consumption in each month. Predicted total consumption of a class was determined by multiplying this sum by the actual number of customers. Similar methodology was used for the R3 rate class; however, the base load was not removed from the regression.

Consumption of the remaining four rate classes (R2 Seasonal, R4, R5 and R6) were not weather- sensitive and did not exhibit sensitivity to the explanatory variables. Total and monthly volumes fluctuate from year-to-year and as such, a five-year rolling average was used to forecast monthly consumption for each of these classes, with the exception of R4 in which a trend is also applied.

The customer connections count was forecasted by applying the geometric mean annual growth rate from 2012 to 2023 to the 2023 average customer count.

3. Supply Options

3.1.Key Assumptions

The appropriate balance of system gas supply and local gas production are considered for the procurement of natural gas commodity in order to meet the demand forecast established in Section 3. The chart below provides an analysis of the supply sources for the 2023 calendar year, including incremental local production. In this Supply Plan, the peak day consumption are compared against compared the Contract Demand of Enbridge Gas System Supply Contract (ENB SA1550), Enbridge Gas Direct Purchase Contract (ENB SA25050), Lagasco Lakeview Contract.

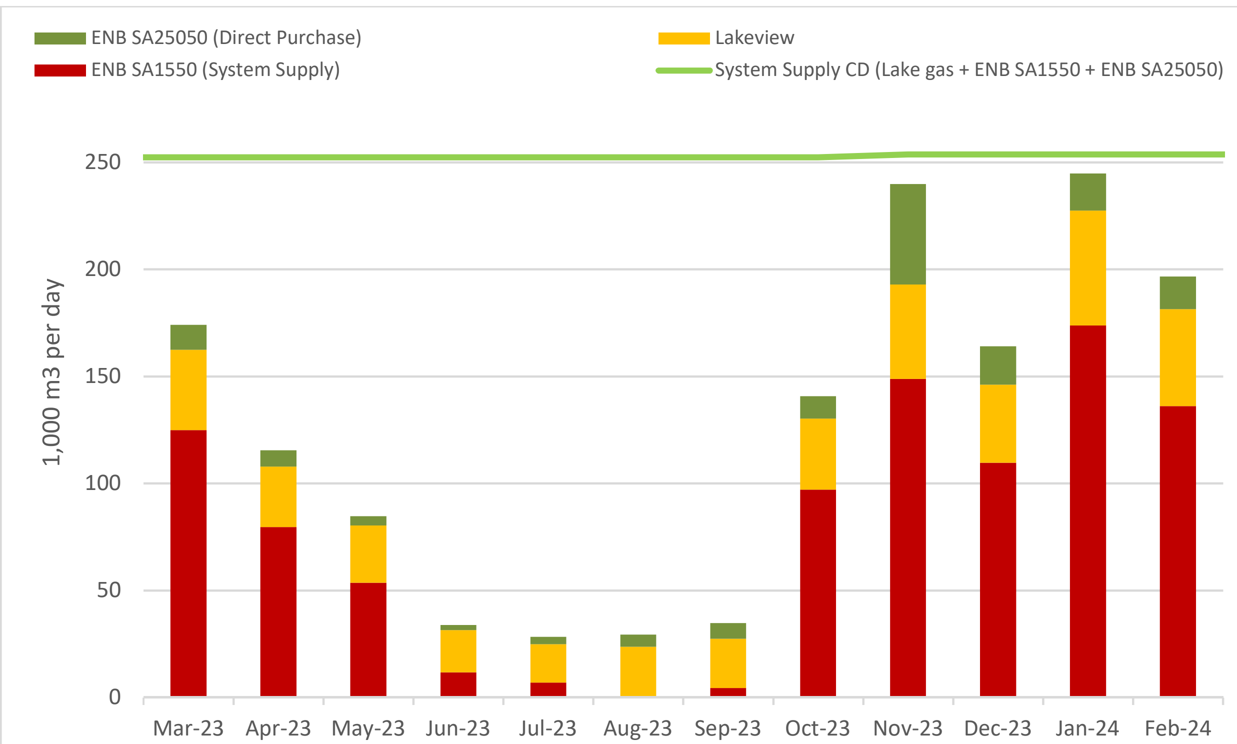


Figure 1 - Max Daily Demand each Month by Source vs Contract Demand, Feb 2023 to Feb 2024

The 2023 Contract Demand was sufficient to meet peak day consumption of the three supply contracts.

While the demand forecast serves as the primary input used to develop the Supply Options, the following base assumptions also underpin each option:

3.1.1.Peak Day/Hour

EPCOR engaged Cornerstone to review and predict system conditions under the current peak gas demand and predict future peak demands. Based on the study, the biggest difficulty in establishing an accurate model for the distribution system was the loading throughout the system. Gas is not metered using district meter stations for each of the towns the system serves, which necessitates that a peak hour consumption estimate be developed for each town center. With the town loads making up a large majority of the consumption, based on the number of customers located in the towns compared to the distributed customers, this introduced a large unknown.

In previous analyses of this system's integrity, the month of November had days that were considered the peak scenario of gas consumption. In November, seasonal agricultural loads are still active and drawing gas from the system. The seasonal agricultural loads, however, are largely interruptible and therefore EPCOR focused on the January 2018 peak load, when seasonable interruptible customers were not using gas.

January 30, 2019 had the highest gas consumption for the historical data provided and the goal was to construct the base case model to reflect the gas meter readings that each Union station was seeing, as well as the pressure recordings at the stations and at the several other points in the system. The modelling was set up with flows in m^3/hour, so a peak hour was chosen for January 5, 2019 based on the hour with the largest meter readings (9:00 a.m.). The total meter readings for the 8:00-9:00 a.m. hour were 9,747 m^3/h, thus all loads had to equal that number.

Additional peak demand was forecasted for forecasted large volume customer additions in 2024 through 2028.

This work provided EPCOR with a demand day road map in order to assist in determining the required Peak Day and firm Contract Demand requirements from its gas supply sources. The roadmap was updated in this Supply Plan to include 2023 actual peak demand and a forecast for 2024 to 2028. EPCOR notes the additional CD required from

Enbridge and the Lakeview Contract over the period covered in this supply plan.

Table 3-1 - Actual & Forecast Demand Requirements

	ACTUAL / FORECAST	Actual and Forecast Peak Demand	Enbridge Contract Demand		Lagasco Contract Demand	Total Contract Demand
			Enbridge Sys Gas	Enbridge DP		
		m3/day	m3/day	m3/day	m3/day	m3/day
2019	ACTUAL	241,670	208,429	13,366	30,856	252,651
2020	ACTUAL	187,720	208,429	13,366	30,856	252,651
2021	ACTUAL	213,131	186,100	35,695	30,856	252,651
2022	ACTUAL	248,955	186,100	35,695	30,856	252,651
2023	ACTUAL	235,813	186,100	35,695	31,912	253,707
2024	FORECAST	299,688	186,100	35,695	75,952	297,747
2025	FORECAST	313,632	193,125	35,695	82,871	311,691
2026	FORECAST	360,600	240,093	35,695	82,871	358,659
2027	FORECAST	363,456	242,949	35,695	82,871	361,515
2028	FORECAST	366,312	245,805	35,695	82,871	364,371

EPCOR will continue to monitor the system's consumption and growth pattern and increase Contract Demand from either Enbridge or Lakeview as needed.

3.1.2. Weather

EPCOR retained Power Advisory to provide a Weather Normalized Distribution System Load Forecast. A copy of this report is provided in Appendix E.

3.1.3. Commodity

EPCOR receives the majority of its commodity under the bundled M9 rate which is based on Enbridge's OEB approved WACOG application. EPCOR currently has three M9 Large Wholesale Service Contracts; SA1550 (System Gas) with a Contract Demand of 186,100 m^3, SA25050 (Direct Purchase) with a Contract Demand of 35,695 m^3 and SA8936 (IGPC) with a Contract Demand of 201,275 m^3.

The balance of EPCOR's commodity requirements are sourced from local production. In Q3 2023, EPCOR Aylmer added source of local supply to the distribution system through the introduction of renewable natural gas (Production D) injected into the system by a new local RNG facility. The facility is expected to increase supply to the distribution system by approximately 3,000 m3 to 13,500 m3 per day, which will be offset by a decrease in volume from other supply sources. EPCOR is assessing options for additional supply from local sources to meet anticipated additional demand from the additional of large volume customers expected to be added in 2024 through 2028.

3.1.4. Transportation

EPCOR incurs gas transportation costs (to/from Enbridge) for storage, load balancing, and transportation across Enbridge's system to EPCOR's distribution system. These costs are recovered in EPCOR's delivery charges as reflected in the EB-2018-0336 cost of service rate filing.

EPCOR currently contracts for an annual Contract Demand in the amount of 186,100 m^3 for its System Gas customers.

EPCOR evaluates its Contract Demand requirements with Enbridge on an annual basis and will balance the need to maximize its usage and minimize over run charges under this contract. For the November 2023 renewal, Enbridge proposed no changes to the Contract Demand for SA1550 (for system gas customers) and SA25050 (for direct purchase customers). EPCOR plans to increase the Contract Demand with the Lakeview contract in 2024 and 2025 to meet expected system gas peak day requirements. EPCOR also plans to increase the Contract Demand with the Enbridge contract in 2025 onwards to meet additional system gas peak day requirements.

3.1.5. Storage

EPCOR relies on its contract with Enbridge for storage, load balancing and transportation.

3.1.6. Daily Balancing Management

EPCOR is not required to Daily Balance its gas supply as that service is provided by

Enbridge under the M9 service agreement.

3.1.7. Direct Purchase Program

EPCOR has Direct Purchase Customers in its system whereby these customers arrange for gas supply and/or upstream transmission services directly with Enbridge or EPCOR's distribution service to deliver gas to end-user locations. Currently, approximately 1% of EPCOR customers are on direct purchase compared to system sales and represent approximately 4.35% of EPCOR's demand profile by volume.

EPCOR relies on the Direct Marketer to deliver the volumes to Enbridge. In accordance with the Bundled T-Service Receipt Contract between EPCOR and the Direct Marketer, if on any Day, for any reason, including an instance of Force Majeure, the Direct Purchase Customer fails to deliver gas then such event shall constitute a "Failure to Deliver" and the Failure to Deliver clause (Section 3.01) in the this contract will take effect. The Direct Marketer will indemnify and hold EPCOR harmless with respect to the excess of any costs and expenses incurred by EPCOR in acquiring such Gas and transportation capacity.

3.1.8. Long-Term Contracts

As discussed in section 3.1.1, EPCOR expects to increase the Contract Demand with Lagasco and Enbridge over the next 5 years to meet expected increase in peak day consumption.

3.1.9. Diversity of Supply

Diversity of supply was identified as a key consideration in the Supply Plan. The introduction of incremental local production in the form of RNG in addition to existing local supply further diversifies the portfolio as demonstrated in the analysis below:

Table 3-2 - Supply Source Breakdown – Forecast and Actual

Supply Source Breakdown-Forecast (% of annual supply volume)					
	Enbridge	Production A & B	Production C	Production D	Total
2028	57.0%	1.5%	32.1%	9.4%	100%
2027	56.0%	1.8%	32.6%	9.5%	100%
2026	55.0%	2.1%	33.2%	9.7%	100%
2025	60.1%	2.7%	27.7%	9.5%	100%
2024	67.2%	2.8%	25.7%	3.8%	100%

Supply Source Breakdown-Historical (% of annual supply volume)					
	Enbridge	Production A & B	Production C	Production D	Total
2023	67.2%	2.8%	25.7%	4%	100%
2022	70.3%	2.6%	27.1%	0%	100%
2021	67.5%	2.7%	29.8%	0%	100%
2020	67.3%	3.3%	29.4%	0%	100%
2019	95.4%	4.2%	0.5%	0%	100%

3.2.Description of Supply Options

EPCOR identified alternative supply options for ENGLP which included the following:

a) Pipeline additions or modifications

b) Additional supply from Enbridge Gas

c) Additional supply from Others

EPCOR determined that to meet forecasted increase in demand, a mix of additional supply from Enbridge and from additional local supply was the best available mix from a cost perspective.

4. Gas Supply Plan Recommendations

Given EPCOR's limited size and resources, the utility recommends it continue its strategy of contracting with Enbridge for the M9 rate, including system supply. Local production, in particular the introduction of gas from Lake Erie, augments Enbridge's system supply in order to ensure reliability of the EPCOR system. Specifically, this incremental lake gas addresses historical low pressure issues and allows EPCOR to displace fixed price local production.

EPCOR is also developing the Southern Bruce natural gas franchise and as EPCOR gains operational experience and measures consumption data associated with this system, it will evaluate potential synergies between the two systems including the M9 system supply option for the Aylmer operation. EPCOR is mindful that should it elect to not take service under the M9 rate for the Aylmer operation, the rate will no longer be available to EPCOR.

5. Gas Supply Plan Execution & Risk Mitigation

5.1. Procurement Processes and Policies

Leading into each contract year (July for IGPC and November for Direct Purchase and System Gas customers), EPCOR will evaluate its current demand, its forecasted growth and direct purchase demand. This will help establish the annual Contract Demand with Enbridge under each of the M9 contracts (System Gas Customers, Direct Purchase Customers and IGPC). EPCOR will also consider the amount of local production it is purchasing on both a firm and interruptible basis when establishing its Contract Demand with Enbridge.

EPCOR has established a monthly review process with its System Gas and Direct Purchase Customers under Rates 3 and 5 to ensure provisions are in place for these customers to not exceed the established Firm Contract Demand. This will ensure the customers consume within the established Firm Contract Demand in the same manner that EPCOR has to operate within the limits set by Enbridge. EPCOR established an annual review of its Rates 3 and 5 customers to ensure they are meeting the Minimum Annual Volume Requirements during each contract year as specified in the rate class descriptions.

Further EPCOR continues to review customer consumption to determine the appropriate rate class for each customer i.e. if their consumption is large enough to qualify for a contract rate. This review will also be conducted if there is a significant change in consumption (volume or profile) of an existing customer.

5.2. Evaluation of Procurement Process and Policies

EPCOR purchases the majority of its commodity from Enbridge. EPCOR does not directly enter into upstream transportation, daily balancing, and seasonal storage or third party commodity agreements and therefore does not establish contracting policies with respect to these services.

As part of its Annual Distribution Capital Planning Process[2], EPCOR reviews the system's peak day requirements and ensures it has sufficient assets and contracting flexibility in order to meet these requirements. These capital plans are filed as part of the EB-2018-0336 Cost of Service rate filing.[3] Contract considerations include:

- The amount of firm Contract Demand capacity required from Enbridge and local producers; and
- The amount of interruptible capacity contracted for under Rate 5 – Interruptible Peaking Contract.

EPCOR intends to file an updated capital plan as part of the upcoming EB-2024-0130 Cost of Service rate filing in June.

[2] This process is subsumed within the "Utility System Plan" evidence of the EB-2018-0336 Cost of service rate filing.

[3] EB-2018-0336, Application and Pre-filed Evidence, Exhibit 2, Tab 3, Schedule 1, at page 2.

5.3. Risk Mitigation Strategy

A key aspect of the execution of this Gas Supply Plan is the identification of risks and the adoption of risk mitigation strategies.

5.3.1. Description

The risk identified is that the M9 Rate will not be offered by Enbridge in the future. EPCOR has reviewed Enbridge's proposed Rate E62 in their 2024 Rebasing application (EB-2022-0200), which is not expected to have material impact to the way EPCOR will manage Aylmer's gas supply under the new rates.

6. Public Policy Objectives

6.1.Renewable Natural Gas (RNG)

EPCOR understands and supports the development of an RNG market and facilitates inclusion of RNG in its gas supply portfolio. EPCOR recognizes the importance of Greenhouse Gas (GHG) abatement across the province, as well as the role that EPCOR plays in supporting the achievement of GHG emission reduction targets.

In Q3 of 2023, EPCOR started receiving RNG into its distribution system. However, EPCOR is not purchasing the environmental attributes of this RNG gas. As such, EPCOR will purchase the RNG as another source of local supply, and will not take ownership of the environmental attributes generated from the production of RNG.

Even though EPCOR is not taking ownership of the environmental attributes resulting from the RNG production, this arrangement ultimately allows for development of RNG production within Ontario. It also provides EPCOR a learning opportunity on how to transact and procure RNG without significant cost impact to the rate base.

One of the key learnings to date is that RNG projects tend to have relatively steady production volumes throughout the year, which presents a challenge to system operations during the summer period when consumption is low, especially for systems like Aylmer where it is not possible for the RNG to physically leave the system. This limits the size and the number of RNG projects to be considered and implemented in the Aylmer system. EPCOR will provide further updates in future Gas Supply Plans and Annual updates once the RNG volume has been introduced into the Aylmer system.

6.2. Demand Side Management (DSM)

When preparing the 2023 update, EPCOR included commentary regarding plans to submit a DSM proposal in its next cost of service filing for Aylmer (or in a separate standalone proceeding), where the plan, the financial impacts and ratemaking implications can be addressed. While this was the intent, EPCOR is not currently ready to do so. This is largely attributable to the transitional state of the DSM framework for natural gas customers in Ontario, and specially the Enbridge DSM supplemental application to be filed in 2024.

After engaging third party vendors, as well as investigating potential collaboration with both Enbridge and the IESO (in response to the Minister of Energy's letter of direction as noted above in section 8.2), EPCOR believes that a collaborative, consistent program offering would be of best interest to its customers and the most effective way to deliver this would be through a shared arrangement with a larger provider.

In order for a DSM program offering to be successful, EPCOR would require several additional resources to prepare an application, launch, fulfill and meet the reporting obligations, which would lead to higher costs for customers if all of these roles were to be filled internally. EPCOR remains open to further collaboration discussions with the IESO and Enbridge to help achieve economies of scale in the DSM portfolio.

6.3. Community Expansion

EPCOR has been actively working to bring secure, reliable and affordable natural gas to unserved communities. A number of customers have requested service and EPCOR has pro-actively responded to those requests and they are considered as part of the 2024 demand forecast.

6.4.Federal Carbon Pricing

As part of the Government of Canada's Federal Carbon Pricing Program ("FCPP"), a federal carbon pricing system has been implemented in Ontario, under the *Greenhouse Gas Pollution Pricing Act, 2018* ("GGPPA") with the following features:

For larger industrial facilities, an output-based pricing system ("OBPS") for emissions-intensive trade-exposed ("EITE") industries applied in January 2019. The OBPS covers facilities emitting 50,000 tonnes of carbon dioxide equivalent ("CO2e") per year or more, with the ability for smaller EITE facilities that emit 10,000 tonnes of CO2e per year or more to voluntarily opt-in to the system; and,

A charge applied on applicable fossil fuel deliveries, as set out in the *Greenhouse Gas Pollution Pricing Act*, Part 1, effective April 1, 2019.

EPCOR continues to file annual applications for FCPP rates and recoverable costs, effective April 1, most recently EB-2023-0274. EPCOR will continue to monitor and assess the potential impact of the FCPP on future customer consumption and conversion decisions.

6.5.Minister of Energy Letter of Direction

On November 27, 2023, Todd Smith, Minister of Energy, provided a letter of direction to Glenn O'Farrell, Acting Chair of the Ontario Energy Board. This letter highlighted the Minister's near-term priorities for the energy portfolio focusing on continuance of energy transition and the OEB modernization. These priorities include:

- Housing, Transportation and Job Creation
- Facilitating Innovation within Ontario's Regulatory Framework

- Distributed Energy Resources (DERs) and Future Utility Business Model
- Electricity and Natural Gas Conservation
- Distribution Sector Resiliency, Responsiveness, and Cost Efficiency
- Electrification and Energy Transition Panel

Specifically regarding conservation, the letter addressed the benefits and expectations of collaboration between Natural Gas and electricity distributors and operators in order to provide customers a consistent view and experience, both for residential and non-residential offerings:

Ontario continues to be a leader in energy conservation with a long history of delivering results and savings for ratepayers. While program coordination between roughly 60 local distribution electricity companies and Enbridge has historically been challenging in this space, the IESO and Enbridge have been successful in providing a one-window program for income tested customers since electricity conservation program delivery was centralized with the IESO. Building on this success, we must now turn our attention to delivering this same level of service to non-income tested residential customers. I ask that the OEB consult with the IESO and Enbridge and report back in April 2024 on how electricity and natural gas low-income and residential programs could be delivered through a single window. As the OEB begins planning for future natural gas energy efficiency programming that would take effect in 2026, I continue to look to the OEB to ensure Ontario electricity and natural gas ratepayer interests are protected and that Ontario takes every opportunity to generate deeper retrofits, more energy savings, and greater emissions reductions while ensuring natural gas costs remain affordable, stable and predictable.

In response to this, EPCOR has engaged with both Enbridge and the IESO to explore opportunities for collaboration and opportunities to leverage this framework into DSM offerings for customers in the future, as further explained in section 8.4 below.

While EPCOR continues to follow policy guidance from the Ministry, there are no direct impacts from the Minister's letter on this filing.

6.6. Integrated Resource Planning

This Supply Plan does not include potential impacts of future IRP projects. As per the OEB Staff Report for the Review of the 2023 Annual Update, consideration of IRP alternatives to facility projects are not properly part of a Supply Plan review and EPCOR should not provide information with respect to options for IRP implementation in its Supply Plans. There are currently no plans to implement IRPs in Aylmer.

6.7. Canada Green Homes Grant

In 2023, grant funding through the Canada Greener Homes Grant is being offered across the country to all eligible Canadian through the Home Efficiency Rebate Plus in Ontario will allow eligible homeowners to access the benefits of both programs through a single application and streamlined process regardless of their home heating fuel type.

The Canada Greener Homes Grant is no longer accepting new applications in March 2024.

EPCOR will continue to monitor and assess the potential impact of the Canada Green Homes Act on future customer consumption and conversion decisions.

7. Current and Future Market Trends Analysis

EPCOR engaged ECNG to perform a "Current and Future Market Trends Analysis". This analysis can be found in Appendix A.

8. Performance Metrics

EPCOR has drafted a performance metric scorecard in order to measure the effectiveness of the Supply Plan. Please see Appendix F for details.

In the Staff Report to EB-2023-0111, OEB staff recommends that EPCOR should provide a more comprehensive list of major policy changes that would impact EPCOR's GSPs both in the long and short term. EPCOR have added a comprehensive list of major policy changes in the Scorecard starting with this Supply Plan Update.

9. Continuous Improvement Strategies

The continuous improvement to the supply planning process undertaken by EPCOR is an important element of the transparency objective of the Framework. EPCOR continues to proactively evaluate new supply and transportation options in accordance with the Framework's guiding principles.

EPCOR will also continue to proactively identify new opportunities to meet its gas supply obligations while meeting the Framework assessment criteria. EPCOR will also continue to review and improve the information it receives for market outlook and forecasting purposes.

EPCOR commenced service to customers in its Southern Bruce franchise area in 2020. There may be opportunities to combine gas supply plans for both the Aylmer and Southern Bruce areas but EPCOR believes that at this time, this opportunity is beyond the scope of this gas supply planning period.

10. Appendices

Appendix A – Market Trends Analysis April 2024 Update

Current and Future Natural Gas Market Trends Analysis Provided by ECNG

As an element of the risk mitigation strategy, the following overview of current and future trends is intended to inform EPCOR of any changes in natural gas market fundamentals which have the potential to impact its ability to execute the Supply Plan. The North American (N.A.) fundamental drivers for natural gas are demand, supply, storage (near term only) and in a more limited/indirect way crude oil, underlying USD/CAD currency and in the longer term the global LNG market. "Near-term" is within the next 12 months, "Mid-term" is 1-2 years after Near-term, "Long-term" is 3-5 years after Mid-term.

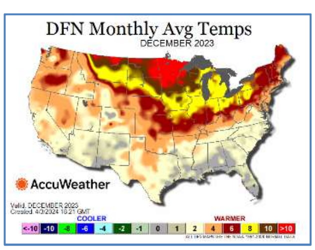
External influences in this outlook are dominated wars in Ukraine and Israel / Middle East influencing security of supplies of crude oil and natural gas. Geopolitical risk has pushed global oil prices upward much more than natural gas due to offsetting warmer than normal winters in both Europe and N.A. leaving end of winter inventories significantly higher than the 5 year averages.

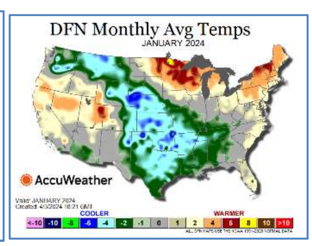
Demand Impact on pricing:

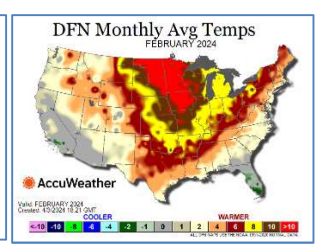
NYMEX and DawnNear-term Mildly Bullish; Mid and Long-term Very Bullish

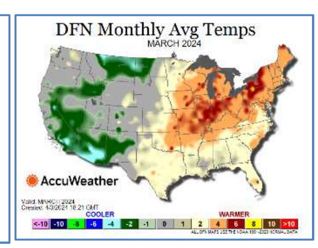
AECO Near-term Bearish; Mid and Long-term Bullish

US natural gas R&C sector consumption in Winter '23/'24 faltered again with winter weather even warmer vs the previous winter. The weather charts below show Departure-From-Normal in DegF with the brightest red, bright yellow and deep red being >10F, ~8F and ~6F respectively warmer than normal.

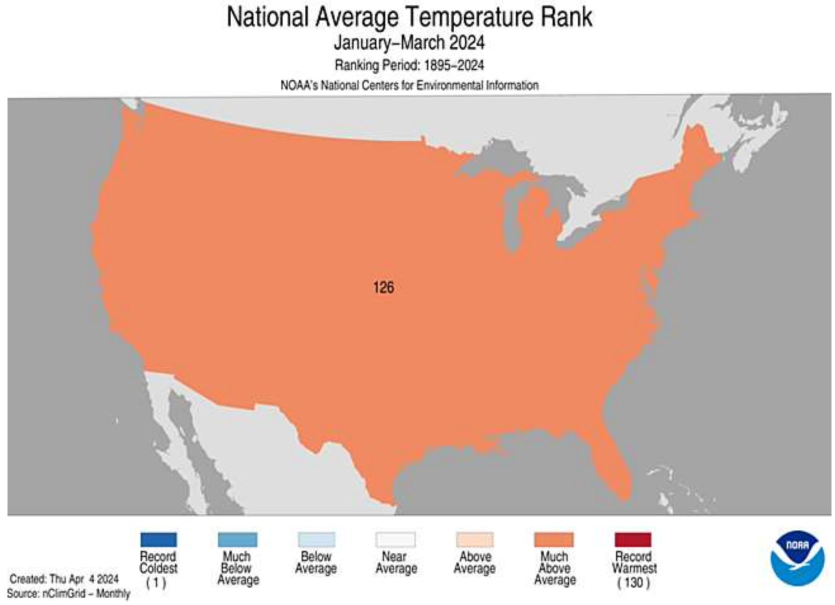




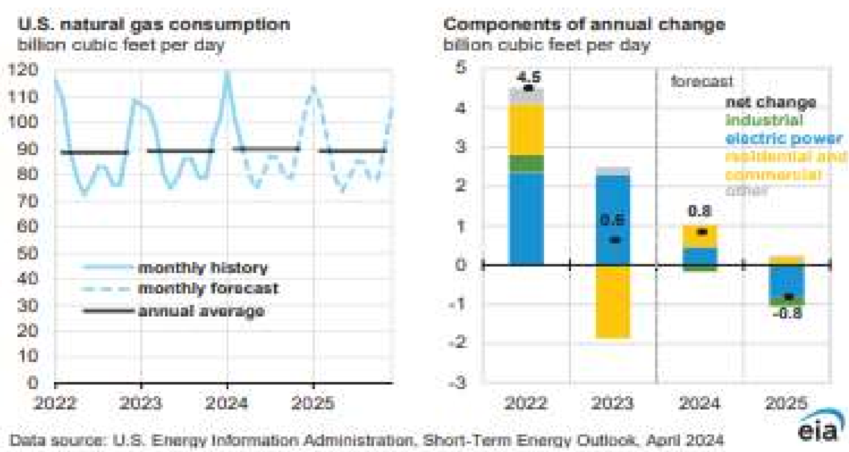




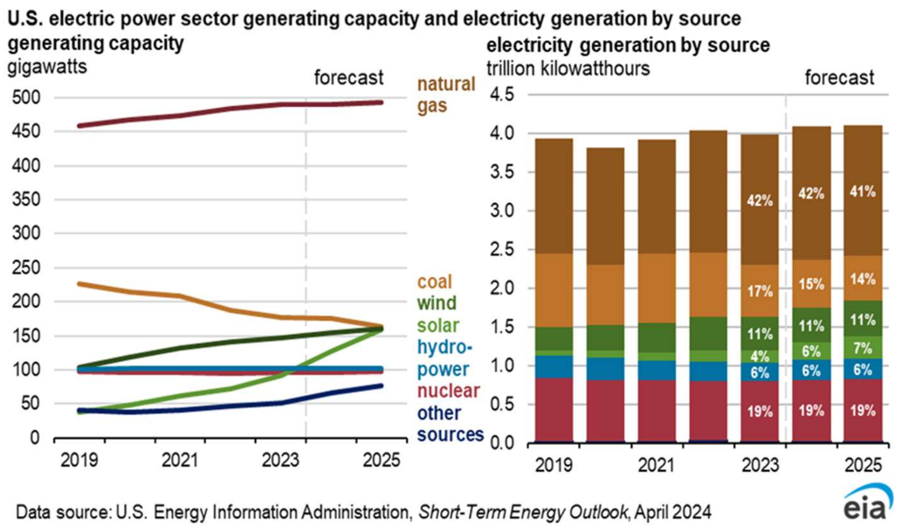
January to March 2024 heat sensitive demand saw the 126th lowest of 130 years as reported below by NOAA. (https://www.ncei.noaa.gov/access/monitoring/us-maps/maps?maps=national-tavg-rank--3--202403)



In the forecast in EIA's most recent Short Term Energy Outlook 2024 - April 2024 (STEO 2024), Industrial demand grew in 2023 vs 2022 and the EIA forecasts modest shrinkages in both 2024 and 2025 by amounts less than 0.5 Bcf/d. Surprisingly gas-fired power generation grew similarly in 2022 and 2023 with modest growth in 2024 (0.4 Bcf/d) and then a drop off in 2025 of 0.8 Bcf/d mostly due to renewables (solar and wind pushing into the generation mix).

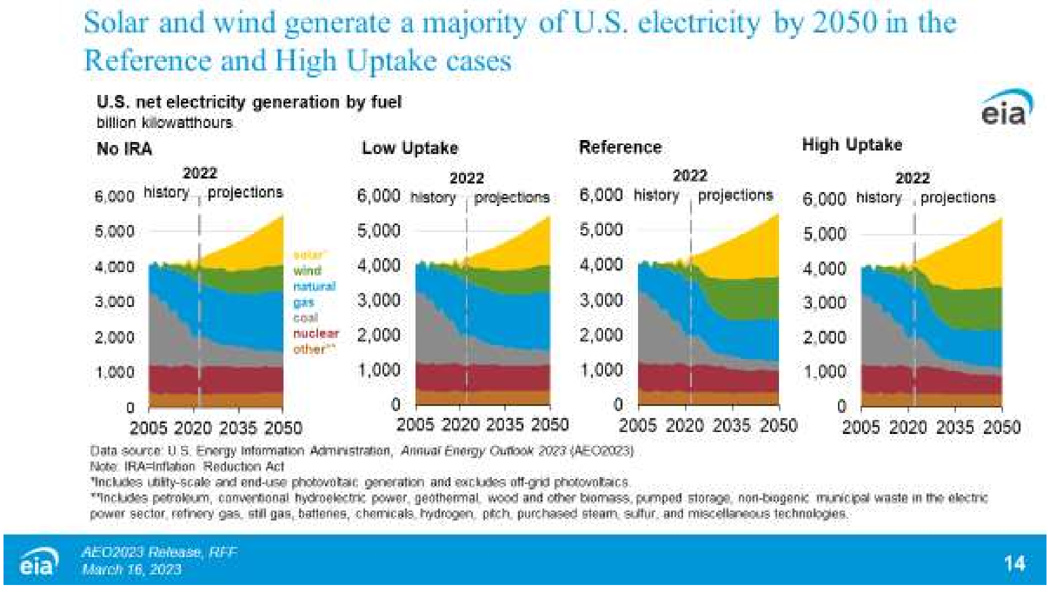


Mid-term and Long-term gas consumption demand growth is largely expected by most forecasters in the United States (U.S.) is in gas-fired power generation. Coal-fired power generation retirements appear to be minimal in 2024 but take a steeper drop in 2025 as seen in the left graph below from STEO 2024. Interestingly in the right graph below, natural gas eclipsed 40% of the total 4 trillion kilowatt-hours generated in 2023. Gas-fired share seems to flatten out at 42% as renewables push out coal-fired generation in 2024 and 2025. Also, gas-fired generation will likely continue running more baseload hours and serve to balance the grid's needs due to intermittent renewables. The energy consuming market continues to lose its ability to fuel switch when natural gas becomes expensive and thus stimulates higher price volatility needed to encourage more supply. No recession type drivers are expected in this forecast.

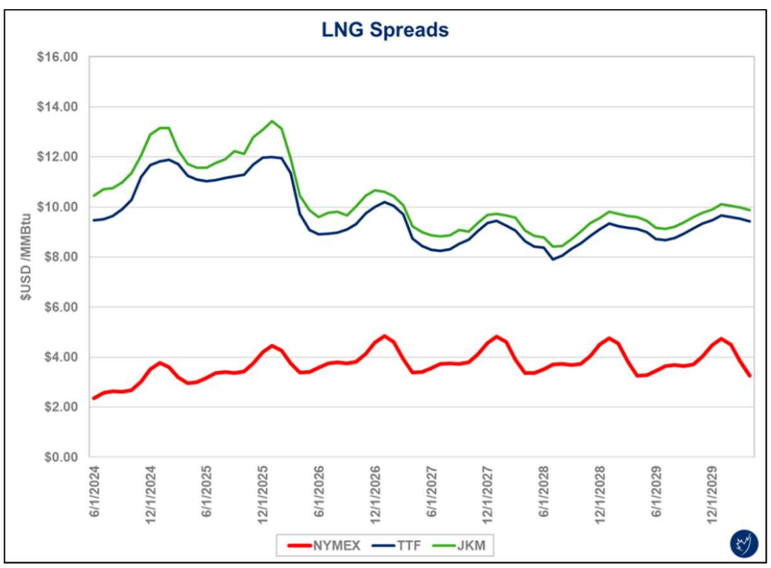


In our opinion, Industrial demand forecast variation is not as material as gas-fired power generation or LNG feedgas for exports discussed later.

The EIA in its latest Annual Energy Outlook (AEO2023), next release expected in 2025, cites in its Reference Case a modest drop of natural gas for power generation to the end of 2030 at the expense of renewables. In its High Uptake Case (high uptake of renewables driven by federal government funding Inflation Reduction Act) natural gas consumption drops more significantly at the expense of renewables. The graphs below show these forecasted trends. ECNG's view continues to be that renewables uptake will be slow due to issues relating to siting projects, regulatory approvals, interconnection queues for generation and storage, rising costs and supply chain issues.

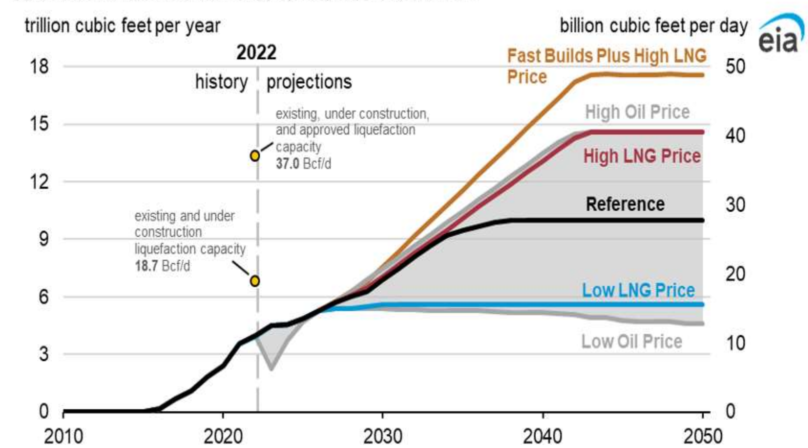


The single largest increase in demand is in exports of liquified natural gas (LNG) in the next 5 years. The chart below shows the ongoing incentive for LNG exports to move NA supply to Global markets.

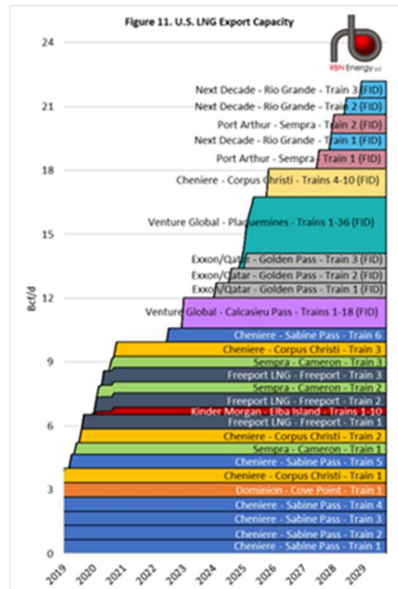


Despite the narrowing of forward pricing, numerous projects have reached Final Investment Decision (FID) and the necessary approvals to proceed to construction. The next graph below to the left, was generated as part of the AEO2023 report, however released May 23, 2023. This shows the staggering total of real potential (of projects) that are in play in the next 5 years alone that have received full regulatory approval from DOE and FERC. More recently the Biden Administration asked for a pause in approvals for those not yet begun construction to consider a wider environmental impact of LNG export projects. The graph below to the right is from RBN Energy showing projects that have reached FID hitting 22 Bcf/d of export capacity by 2030. One item to note as well is that most of these projects use natural gas to generate the power needed to liquify the gas and it is typically at least 10% so including the feedgas of those projects, over 24 Bcf/d of new supply is needed. Post 2025 the pipeline grid will be challenged to deliver the necessary supply on time from reserves to liquefaction sites.

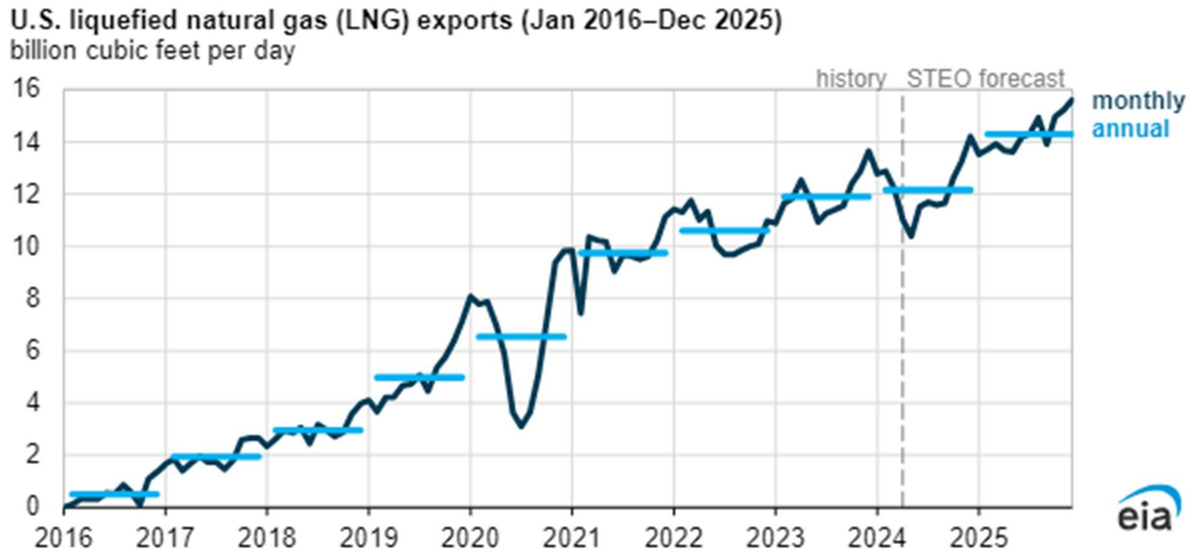
Figure 1. U.S. liquefied natural gas (LNG) exports, AEO2023



Data source: U.S. Energy Information Administration, *Annual Energy Outlook 2023 (AEO2023)* and LNG Capacity Tracker
Note: Existing, under construction, and approved LNG capacities are baseload capacities. Shaded regions represent maximum and minimum values for each projection year across the AEO2023 Reference case and side cases.



In 2023, U.S. LNG exports averaged 12.0 Bcf/d and including fuel gas for refrigeration 13.0 Bcf/d with total capacity equal to just over 15 Bcf/d (the difference coming from planned maintenance or unexpected outages). EIA estimates for 2024 only marginally more than 2023's utilization rates. However, in 2025 the expectation is for exports to grow throughout that year and to average 14.4 Bcf/d, with total feedgas approaching 16 Bcf/d with two additional projects ramping up to full production. If high load factors can be maintained this demand continues to be the most significant contributor to a tight supply-demand balance in N.A. Imports and exports to/from Canada are not expected to grow or fall materially in the near-term time horizon as pipelines are operating at near capacity. However, STEO commentary cites an almost 1 Bcf/d increase in US exports to Mexico in 2024-25 as several expansion pipelines have not reached full service at this point in time.



Expectations for exports to Mexico during this outlook's horizon (5 years out or more) could see average exports to Mexico well exceed 7 Bcf/d from the current flows of 5-6 Bcf/d. This increased demand is mostly for LNG liquefaction for Pacific side exports which shorten LNG routes to Asia and lower transport costs by approximately $2 US/MMBtu. Costa Azul is likely the first Mexican LNG export project supplied via with TC Energy receiving FERC approval of its North Baja Xpress Project in Arizona accessing the Permian supply basin. LNG projects Golden Pass and Plaquemines publicly state commissioning in late 2024, start-ups are slow and specifically Plaquemines has stated a 2 year start up is expected.

https://www.eia.gov/todayinenergy/detail.php?id=60944

There are also LNG export projects to the Canadian Pacific Coast for Western Canadian Sedimentary Basin (WCSB) supply that are on track to begin commissioning in late 2024 and throughout 2025. LNG Canada's Phase 1 with two trains of 0.9 Bcf/d each is now expected to fully flow in late 2025 to early 2026. Next is Woodfibre at 0.3 Bcf/d, expected to begin service in 2027 (has not changed its start date). Cedar LNG's 0.4 Bcf/d project is now expected to flow in 2028-29 (delayed from 2027). The Ksi Lisims LNG 1.7 Bcf/d project has emerged on West Coast targeting flow by 2028-2029. This comes to a Canadian probable total of 4.2 Bcf/d by 2029, not including pipeline fuel gas and potential gas for power generation (depending on the project). As a result, we believe current forward pricing for calendar years 2025-2028 at AECO now over $4.00 CAD/GJ are also likely to persist. Other demand growth sectors have been mostly in AB in coal-fired generation retirements and in oil sands cogeneration of steam and power. Some oil sands production growth is likely as Trans Mountain Pipeline (TMP) comes into service mid-2024 leaving spare oil export capacity by rail. Coal-fired generation retirements are now complete with only 0.3 Bcf/d increase in average gas consumption expected as a result. Combined gas demand growth of oil sands and coal displacement generation could exceed 0.5 Bcf/d.

Finally, a new possible significant power demand that is emerging is for computer servers driving Artificial Intelligence (AI) development and subsequent data centers required. Estimates by experts range from 3 to 16 Bcf/d of gas-fired power generation depending on the mix of generation sources available to meet those growing needs. The timeframe for this demand growth is late in this decade and into the next.

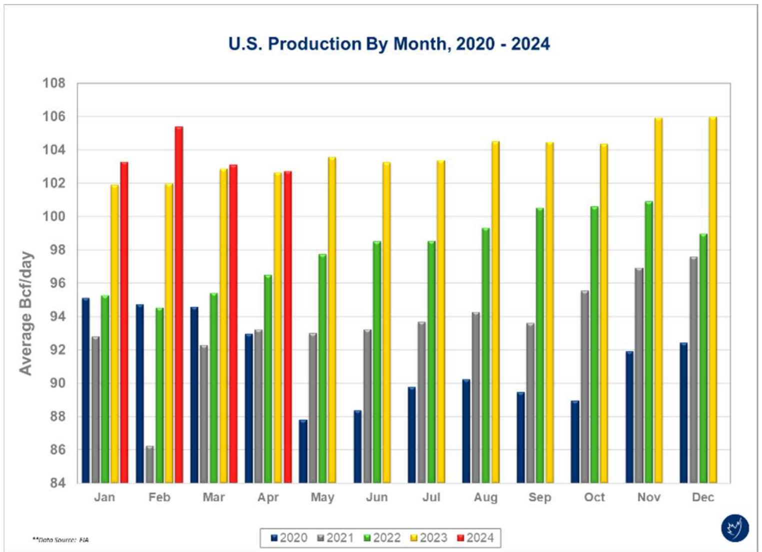
The US demand outlook for 2023 and beyond is for modest to no growth in domestic demand from R&C and industrial markets. Growth in the next 2 years in gas-fired power generation sectors offset by renewables driven by IRA funding but on a modest uptake. Demand growth will clearly come from significant LNG exports and associated feedgas for liquefaction cooling.

Supply Impact on pricing:

NYMEX and DawnNear-term Very Bearish; Mid and Long-term Very Bullish

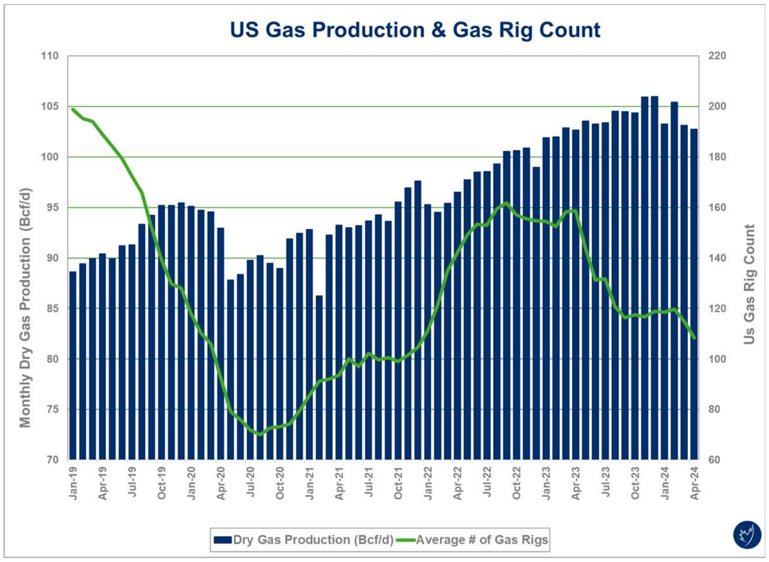
AECO Near-term Very Bearish; Mid and Long-term Mildly Bullish

U.S. dry gas production (supply) growth has been impressive since Q4 2023 and in early 2024 driven originally by high prices back in 2022 and LNG export projects expected to substantially flow in 2024. US production has impressively moved from an average of 103.7 Bcf/d in 2023 to an exit production in November and December 2023 of 106 Bcf/d. This production gain was halted by a brief but significant polar vortex storm that dropped daily production down (wellhead freeze-offs) to an estimated 87 Bcf/d before returning to over 105 Bcf/d by early February. Without this event it was likely that 4 consecutive months could have reached 106 Bcf/d.



As a result of a combination of 1) a significantly warmer than normal winter across NA, 2) new LNG project delays, 3) Freeport LNG ongoing production issues, 4) lower European LNG demand and 5) impressive US producer increases in supply, a significant drop in gas pricing was necessary. This price drop is necessary to drive a pullback on supply growth to balance the inventory surplus (exiting the winter).

The EIA is forecasting from April to October 2024 about 103 Bcf/d which is 1 Bcf/d less than last year for the same summer period. At this point in time that forecast appears realistic. In the first 4 months of 2024 several large producer announcements regarding 2024 CAPEX had similar themes of 1) oil directed drilling focus, 2) reduced overall CAPEX vs 2023, 3) expectation of increased "drilled-but-uncompleted" wells inventory which would lead to spare capacity for future production as prices recovered (as supply and demand return to balance). In other words, the messaging was that despite dropping rigs over the year, should the market need additional supply producers would respond relatively quickly. A final observation is that the supply community continues to produce more supply with less rigs (see chart below).



In the mid to longer term, new blocks of supply need to arrive on time to meet new LNG blocks of demand. Pipeline projects in Texas, Oklahoma and Louisiana appear to be on schedule with only modest headwinds. The challenge will be for adequate new supply to arrive on time or will portions come from existing markets thus driving up the price. Prolific reserves exist in Alberta and the US Northeast such that those more local markets do not rely on supply from Gulf of Mexico deposits. There is a possible scenario whereby new pipelines will be needed to move gas continentally north to south to fill the gap. These are the pipeline projects that will likely face stronger headwinds. This could lead to a higher NYMEX price that is not fully translated into the northern parts of North America. In other words, Dawn basis discounts to NYMEX may grow later in this decade as a result.

The Western Canadian Sedimentary Basin (WCSB) production has grown substantially in preparation for LNG Canada but also, higher oil sands demand (TMP start up) and Alberta power generation demand (complete phase out of coal-fired generation) and increased access to domestic and export markets through significant NGTL (Nova Gas Transmission) expansions completed. We continue to see evidence of significant supply growth in BC’s prolific Montney shale formation as this is primarily the supply source for LNG Canada via TC Energy’s Coastal GasLink.

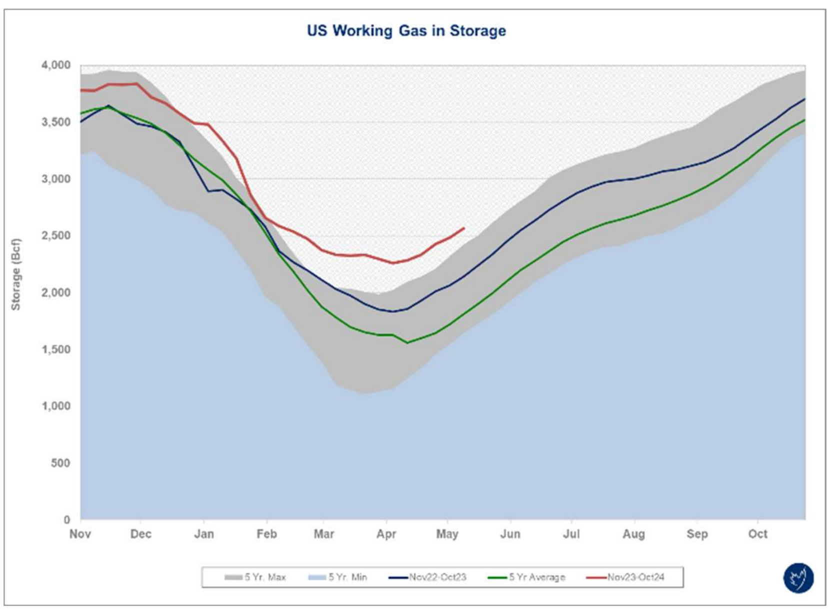
The supply response in the WCSB is expected to be quicker on a percentage basis compared to the U.S. however additional supply will be suppressed by limited pipeline capacity to the US and Eastern Canada to impact the NYMEX / US market. These constraints contribute to a significant above 5 year average storage level due to only modestly growing BC and AB demand which continues to drive the bearish sentiment in the short run. Mid and Long-term the sentiment moves towards bullish as LNG Canada begins circa mid-2025 into 2026 and then doubling by 2030 putting stress on supply and pipelines to deliver on time.

Storage Impact on pricing:

NYMEX and Dawn Near-term - Very Bearish; Mid and Longer Term – Mildly Bullish

Aeco Near-term - Very Bearish; Mid and Longer-term – Mildly Bullish

Total U.S. working inventories on April 5, 2024 ended well above the five-year average of 1.65 Tcf by approximately 630 Bcf (surplus). Most industry forecasters see the end of the 2024 injection season ending in a surplus to the five-year average but only between 150-300 Bcf, mostly due to physical limitations of storage (capacity and deliverability) and current sentiment that producers will curtail supply at prices persistently below $2.00 US/MMBtu. The U.S. Energy Information Administration estimates that natural gas in storage will end the injection season at a record 4,120 Bcf, or 10% above the five-year average. Demand side elasticity has been greatly reduced by coal plant retirements over the last 5 years to balance storage levels through the summer.



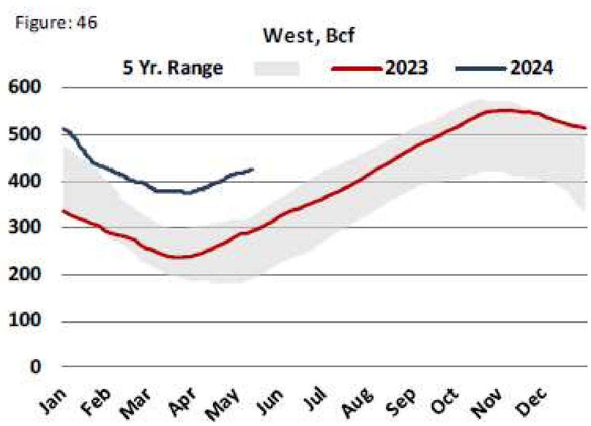
The table below from National Bank shows US withdrawals in Bcf/month per winter (Nov-Mar). It is not surprising that this year is the lowest for storage withdrawals in the last 9 years. (at the time this table was created Mar'24 withdrawals were not yet finalized and the 100 estimate below in red is likely overstated).

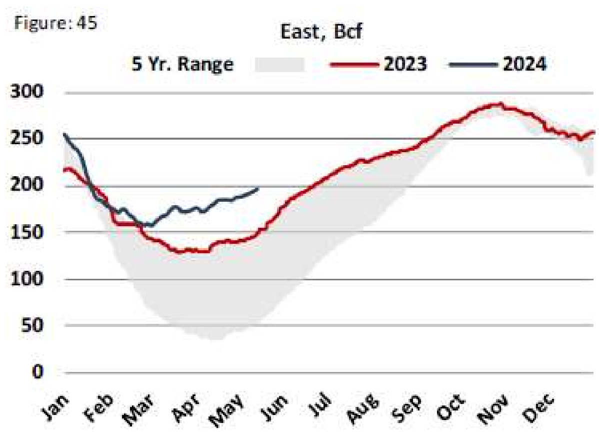
Bcf	24/23	23/22	22/21	21/20	20/19	19/18	18/17	17/16	16/15	Avg
Nov	5	-108	-84	21	-129	-186	-96	-43	52	-63
Dec	-302	-576	-429	-612	-431	-363	-748	-739	-367	-507
Jan	-785	-422	-894	-725	-493	-581	-809	-601	-717	-669
Feb	-268	-403	-631	-785	-532	-614	-484	-306	-392	-490
Mar	-100	-231	-183	-45	-150	-346	-285	-279	-34	-184
Total	-1,449	-1,739	-2,220	-2,145	-1,734	-2,090	-2,422	-1,967	-1,457	-1,913

EIA, S&P Global, NBC

A higher US storage balance means approximately 1-2 Bcf/d more supply available in the upcoming winter. Supply levels will need to rebound to 105 Bcf/d or more to balance the additional LNG export growth expected in 2025 and growing gas-fired power generation.

In Canada, storage at winter's end in Alberta (essentially the "West" graph below) is above the 5-year high, similar to storage at Dawn (essentially the "East" graph below) although different paths to get there.





Storage graphs from RBN Energy LLC 2021 on May 15, 2024.

All these current storage balances lead to a more bearish sentiment on summer gas pricing in 2024 and winter 2024/25 as a significant surplus to the 5-year average is carried into the winter (US and Western Canadian). In the Mid to Long Term, our sentiment appears to be moving into a Mildly Bullish realm simply due to the lack of storage capacity growth in proportion to the total market growth (including LNG exports) to offset the loss of market elasticity with emissions reducing coal-fired generation retirements and to a smaller extent industrial dual-fuel boiler retirements over the past 5-10 years.

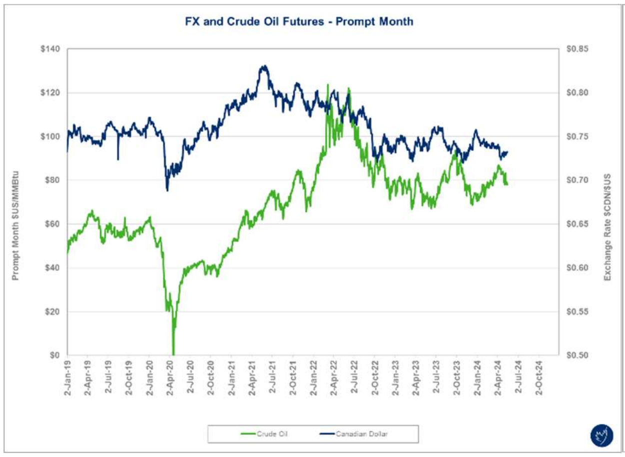
Crude Oil and Foreign Exchange Impact on pricing:

NYMEX and Dawn Near-term and Longer-term - Very Bearish

AECO Near-term – Neutral; Longer-term - Mildly Bullish

West Texas Intermediate (WTI) oil pricing in late 2023 and early 2024 has been moving between about $70 and $90 USD/b after reaching $120/b shortly after the war in Ukraine began in February 2022. The risk premium currently is more driven by the Israeli-Hamas (and Iran) and not as much by the ongoing Russia-Ukraine war. These ongoing wars should continue to incent a quicker pace to bring on more renewable energy sources. However, they continue to be impeded by higher cost of raw materials, interest rates and power grid infrastructure planning. The use of fossil fuels, mostly coal and oil continue to be used to bridge the timing gap and provide energy security during intermittent daily/weekly stretches in the long term. The previous EIA long term forecasts have not been updated since this Appendix was updated where the expectation of the US remaining a net exporter of petroleum products continues into the distant future (2050). Crude oil pricing continues to economically drive the supply of US oil especially from the Permian basin (Texas and Oklahoma) and the Baaken basin (North Dakota) resulting in associated natural gas supply which is predominantly the reason for our continuing bearish sentiment in this category. Regarding AECO, impact of crude pricing has not influenced a stronger Canadian dollar of late however, as TMP comes online at full output it will enable Western Canadian producers to realize much higher oil prices (less discounting to WTI) due to supply being restricted. When this happens, additional crude production will lead to additional gas demand for steam and power which is the primary driver to our Mildly Bullish sentiment in the long term at AECO. In the near term, crude oil market has little impact on FX or additional supply on WCSB supply so Neutral is our sentiment.

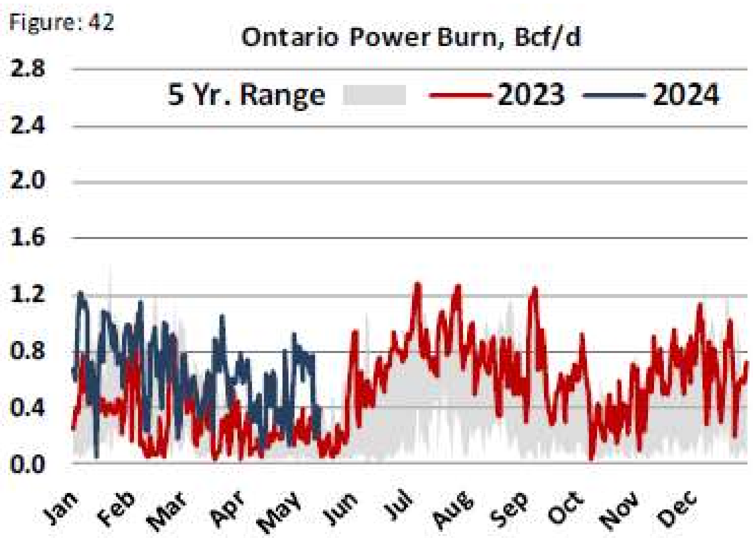
The next two graphs show WTI pricing with the U.S./Canadian foreign exchange (FX) and FX with the price of gas in the WCSB (AECO). It appears the Canadian dollar weakness has not contributed the AECO price fall since mid-2022 to the present.



Dawn Market Hub Discussion

Natural gas primarily flows into the Dawn Hub ("Dawn") from the WCSB and from the U.S. Marcellus and Utica shale plays in the Appalachian region as well as from the Chicago Citygate (a market Hub with excess supply from WCSB, Baaken oil/gas shale formation, Rockies, Mid-Con and the Gulf of Mexico supply regions). There are no new supply pipeline projects expected in the Dawn connected infrastructure over the supply planning period that will shift the fundamental supply and demand dynamics to a degree that will impact the viability of the Supply Plan. With its multiple pipeline connections to the largest supply basins in N.A. providing supply reliability and access, the Dawn market can be vulnerable to pipeline contracting, renewals and long-term toll negotiations between pipelines and its shippers (suppliers, distribution utilities, marketers, and large industrial buyers). Within the next 5 years, some long-term contracts will expire or may be reopened and may not be renewed under the same terms. This change in contracting can alter the flow dynamics into and out of Dawn which will influence the price of gas there. Despite these potential undercurrents, the Gas Supply Plan is expected to be able to deliver on the guiding principles of cost-effectiveness, reliability, and security of supply.

Nearer term Dawn basis forward pricing curves are showing trends that are at a larger discount to NYMEX of late likely due to the excess storage gas remaining from the second consecutive warm winter at Dawn and at sites neighboring Midwest US (mostly Michigan). The mild weather in early 2024 again surprisingly did not lower demand from Ontario gas-fired power generation fleet and we expect similar-to-higher demand as was seen last summer to back up continuing nuclear refurbishments in Ontario plus supporting modest increased power demand year-over-year. Surprisingly the forward price curves at Dawn continue are trading only modestly narrower of a discount to NYMEX in winters and summers starting November 2025 likely due to only modest demand growth perceived low risk of long-term pipeline contracts to Ontario not being fully renewed. The results of the Independent Electricity System Operator's Expedited Long-Term RFP (E-LT1 RFP) due in mid-2023 resulted in just under 300 MW of gas-fired power generation additions to be connected within the risk horizon of this study. There have also been announcements by the Ontario Government of subsidizing new steelmaking technologies at Sault Ste. Marie and Hamilton that will likely increase either the power needs and/or the gas supply needs should these opportunities become be realized later in this decade. All these increases in demand amount to approximately 0.1-0.2 Bcf/d of new natural gas demand in Ontario.



Ontario Power Burn from RBN Energy LLC 2021 on May 15, 2024.

The current Dawn basis market looks like good value however based on EPCOR's lack of interest in purchasing forward basis, which is in USD, there is no purchase opportunity (based on this index). However, there continues to be upside price risk in the Dawn market from modest demand growth, no new supply, and the low risk of supply (transport) non-renewals.

Summary table of market sentiments below.

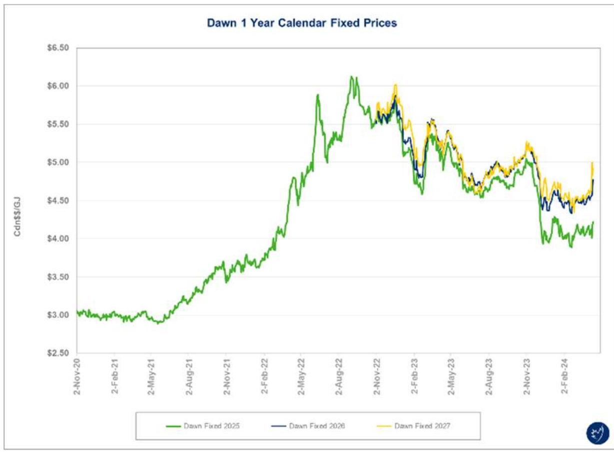
	NYMEX and Dawn		AECO	
Market Driver	**Near-term**	**Mid to Long-term**	**Near-term**	**Mid to Long-term**
Demand	**Mildly Bullish**	**Very Bullish**	**Bearish**	**Bullish**
Supply	**Very Bearish**	**Very Bullish**	**Very Bearish**	**Mildly Bullish**
Storage	**Very Bearish**	**Mildly Bullish**	**Very Bearish**	**Mildly Bullish**
Crude Oil & FX	**Very Bearish**	**Very Bearish**	**Neutral**	**Mildly Bullish**
Overall	**Mildly Bearish**	**Bullish**	**Very Bearish**	**Mildly Bullish**

Near-term Summary on pricing:

NYMEX and Dawn Mildly Bearish

AECO Very Bearish

In the next 1-2 years modestly growing LNG exports, increased gas-fired power generation demand, offset by high inventories at winter's end, with appear to be adequate year-over-year increases in supplies make for a continued well supplied short term market. As a result, NYMEX and Dawn price outlooks in the short term are likely to stay at historic lows until either sustained higher LNG exports resume over 15 Bcf/d and/or a normal winter does not provide the market with a supply surplus. The forward Dawn price for 2025 has upward volatility risk to the current forward prices shown in the graph below with normal winter weather scenario. AECO pricing is likely to stay suppressed with abundant storage inventories until LNG Canada flows at steady-state which will draw-down storage as new supply attempts to match the new block of demand. We are confident that the time needed for new supply to respond will be less than a year. Expected exports to the US will be modest as regional storage surpluses weigh on local Midwest US pricing. Current forward pricing history is found below.


Dawn 1 Year Calendar Fixed Prices
Cdn$$/GJ
$6.50
$6.00
$5.50
$5.00
$4.50
$4.00
$3.50
$3.00
$2.50
2-Nov-20
2-Feb-21
2-May-21
2-Aug-21
2-Nov-21
2-Feb-22
2-May-22
2-Aug-22
2-Nov-22
2-Feb-23
2-May-23
2-Aug-23
2-Nov-23
2-Feb-24
Dawn Fixed 2025
Dawn Fixed 2026
Dawn Fixed 2027


Aeco 1 Year Term Prices
$CDN/GJ
$5.50
$5.00
$4.50
$4.00
$3.50
$3.00
$2.50
$2.00
4-Jan-21
4-Mar-21
4-May-21
4-Jul-21
4-Sep-21
4-Nov-21
4-Jan-22
4-Mar-22
4-May-22
4-Jul-22
4-Sep-22
4-Nov-22
4-Jan-23
4-Mar-23
4-May-23
4-Jul-23
4-Sep-23
4-Nov-23
4-Jan-24
4-Mar-24
4-May-24
4-Jul-24
4-Sep-24
4-Nov-24
Nov24-Oct25
Nov25-Oct26
Nov26-Oct27
Nov27-Oct28
Nov28-Oct29

Long-term Summary on pricing:

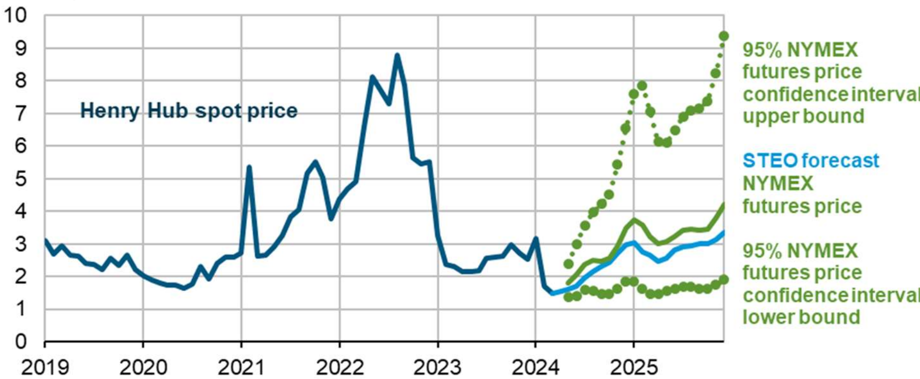
NYMEX and Dawn Bullish

AECO Mildly Bullish

Three to five years out, in the U.S. the expectation of significant growth in LNG exports, modest economic growth, continued fuel of choice in power generation and slow to arrive (on time) supply growth puts pressure on forward pricing to move upward. Local pipelines appear to be planned to match the supply needs of the coming LNG growth surge but there may be inadequate new supply from the local basins, causing the upward price risk. The lack of market elasticity accelerates price volatility (as we saw in 2022) to encourage new supply or to have LNG exports slow down to bring demand in balance with supply. The NA gas market will most likely be influenced by global LNG pricing before the end of the decade. Storage expansions may be necessary as well to meet the intermittent needs of natural gas-fired power generation as it supports renewable generation as supporting peak winter heating demands. US natural gas production can respond in the years ahead but there may be significant lags in pipeline capacity access to bring supply from north to south. The current forward landed cost of gas at Dawn currently resides around $5.00 CAD/GJ for the calendar years 2026-2029. This is good value as the cost of raw materials, labour and global energy prices are likely to persist and support this price in the mid to long-term. The AECO forward pricing volatility is limited to a shorter time frame with evidence of strong supply growth in 2023 coupled with high storage inventory ahead of Phase1 of LNG Canada start up. Supply access necessary to fill LNG Canada's start is capable, however, coordination timing could lead to intermittent daily and monthly discounts and/or premiums for several months until steady state is achieved. There continues to be lesser of a concern of WCSB supply meeting new upcoming Canadian LNG export expansion needs relative to the risk of US LNG expansion growth being met by timely supply.

The chart below speaks volumes to the range of future price outcomes (green dots) derived from options market data which in turn come from recent historical price volatility.

Henry Hub natural gas price and NYMEX confidence intervals
dollars per million British thermal units



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, April 2024, CME Group, and Refinitiv an LSEG Business

Note: Confidence interval derived from options market information for the five trading days ending April 4, 2024. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Appendix B – ECNG Credentials

ECNG Energy Group

ECNG Energy Group is Canada's largest full-service energy management consultant that works exclusively for the end-user in contracting for natural gas and electricity supply as well as delivery services. Further, we provide complete solutions ranging from energy conservation to electricity generation. We manage a volume of approximately 150,000 gigajoules per day of natural gas and 2.5 billion kilowatt hours annually on behalf of our clients, making ECNG the largest purchaser, other than the major utilities, in Canada. The advantages of retaining ECNG are access to specialized in-depth industry expertise, encompassing day-to-day market knowledge, utility rate options, existing regulatory framework, impending changes in these ground rules, and contact with a wide range of reliable gas suppliers.

ECNG's fees are fully transparent. At no time does ECNG take title to supply nor do we receive supplier kickbacks on any natural gas or electricity supply procurement transactions. The client always pays the true cost as offered by the supplier with zero margins being given back to ECNG. This ensures we always achieve the utmost competitive and transparent pricing while providing end-use consumers with objective and expert energy advice.

ECNG has been in business since 1987 and has built a large and loyal client base, including many of Canada's leading corporations, retailers, healthcare providers and associations. Our service to these clients includes over 21,000 end-use locations in all deregulated jurisdictions across the country. With this scale of operation, ECNG receives virtually every cost saving proposal from the supply and transportation communities. Finally, economies of scale and scope permit ECNG to provide its services at a fee that is a small fraction of the delivered cost of your energy. Additional information is available by visiting our web site www.ecng.com.

ECNG PRINCIPALS CVs

Angelo P. Fantuz – Director, Client Services

A Professional Engineer, Angelo brings 35 years of experience to his current role advising Canada's large commercial and industrial end-users about natural gas and electricity procurement and developing procurement strategies for clients. Angelo and his team are also responsible for monitoring regulatory development in order to ensure ECNG and its clients are prepared for what's ahead. Prior to joining ECNG in 2003, Angelo held senior roles at Eastern Pan Canadian/EnCana and Union Gas Limited. While at Union Gas he was a key sponsor in the development of Gas C.A.R.E. relational database to track, control and schedule the gas flow between Union Gas and its interconnected pipelines. He also testified at the Ontario Energy Board defending gas costs embedded in customer rates.

Dave Duggan – Director, Energy Supply & Market Risk

One of Canada's leading authorities on energy commodity purchasing and market fundamentals, Dave is a respected thought leader. He has shared his expertise and understanding of the Ontario and Alberta power markets and Eastern and Western Canada natural gas markets at various conferences presenting multiple times at EMC's Future of Manufacturing Conference, BOMA Canada's BOMEX – Canada's Building Excellence Summit and other conferences. Since 1995, he has held various senior leadership roles within ECNG and executed thousands of natural gas, power and transportation hedge purchases. He is currently responsible for setting market strategy and leading the Energy Commodity Supply and Price Risk Management team, which procures natural gas and electricity supply for utilities, institutional, commercial and industrial clients across Canada. Dave and the team collect and assess market intelligence and conduct fundamental analysis and financial modeling of risk management strategies for natural gas and electricity.

Paul Weingartner – Director, Client Services

Paul is both a Certified Energy Manager and Certified Energy Auditor with almost 20 years' experience building Canada's largest direct-purchase programs across multiple industries. He is a subject matter expert and speaker for organizations such as: the Canadian Healthcare Engineering Society, where he currently serves as Chair of its Corporate Advisory Council; the Independent Electricity System Operator; and Natural Resources Canada, among others. He joined ECNG Energy Group in 2008 after managing national energy programs for HealthPRO Procurement Services. Paul is responsible for managing ECNG's largest clients, developing and implementing customized multi-pronged commodity hedging strategies designed to meet their unique needs and bringing added value by identifying opportunities in the highly complex and volatile natural gas and electricity markets.

Steve Williams – Senior Energy Analyst, Supply & Risk Management

Steve has a deep understanding of the complex Canadian natural gas and power markets, from pricing to storage to logistics and more. He analyzes the markets to transact cost-effective natural gas and power deals in Ontario and Alberta. Steve's training as an accountant informs his detailed approach and helps ECNG's clients create impactful commodity strategies. He joined ECNG in 2007 after building his career in finance at Horizon Utilities and Burlington Hydro.

Althea Rothwell, Senior Consulting Analyst

Althea Rothwell has over 20 years of industry experience ranging from pipeline maintenance to operational controls. Working closely with utilities, pipelines and customers, Althea maintains high standards in meeting operation, supply and utility objectives. Drawing on past experience within the Accounting and Financial Trades sector, Althea provides detailed and accurate reporting to clients regarding contracted financial and volumetric balancing of natural gas.

Appendix C – DETAILED SUPPLY/ DEMAND FORECAST

SUPPLY FORECAST ANALYSIS

Production A and Production B (Formerly NRG now owned by Lagasco)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2028	44,003.57	43,417	42,838	42,267	41,703	41,147	40,599	40,057	39,523	38,996	38,476	37,963.21	490,990
2027	51,694.27	51,005	50,325	49,654	48,992	48,339	47,694	47,058	46,431	45,812	45,201	44,598	576,803
2026	60,729	59,919	59,120	58,332	57,554	56,787	56,030	55,283	54,546	53,818	53,101	52,393	677,613
2025	71,343	70,392	69,453	68,527	67,613	66,712	65,822	64,945	64,079	63,225	62,382	61,550	796,043
2024	81,226	78,014	81,592	80,504	79,431	78,372	77,327	76,296	75,278	74,275	73,284	72,307	927,904
												Decline Rate	16%

Enbridge (Supply)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2028	3,613,776	3,099,349	2,674,583	1,961,075	783,795	211,514	292,386	168,058	269,832	1,998,050	4,110,007	3,528,421	22,710,848
2027	3,533,259	3,038,101	2,600,811	1,880,151	734,729	174,703	255,181	131,529	233,814	1,930,002	3,990,903	3,468,877	21,972,060
2026	3,452,236	2,975,998	2,526,608	1,799,167	685,160	137,265	217,386	94,409	197,196	1,862,148	3,873,049	3,408,683	21,229,305
2025	3,370,527	2,912,858	2,451,786	1,717,918	634,875	98,983	178,787	56,487	159,770	1,794,269	3,756,221	3,347,664	20,480,145
2024	3,601,874	2,709,427	2,195,091	1,942,224	788,812	165,062	217,377	104,296	274,919	1,944,303	3,464,203	3,197,994	20,605,582

Production D-(RNG Supply)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2028	436,865	394,588	398,877	330,865	211,386	137,861	142,456	142,456	206,791	341,894	422,773	436,865	3,603,676
2027	436,865	394,588	398,877	330,865	211,386	137,861	142,456	142,456	206,791	341,894	422,773	436,865	3,603,676
2026	436,865	394,588	398,877	330,865	211,386	137,861	142,456	142,456	206,791	341,894	422,773	436,865	3,603,676
2025	436,865	394,588	398,877	330,865	211,386	137,861	142,456	142,456	206,791	341,894	422,773	436,865	3,603,676
p	265,145	259,116	361,585	330,865	211,386	137,861	142,456	142,456	206,791	341,894	422,773	436,865	3,259,194

Production C-(Lakeside Production owned by Lagasco)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2028	1,621,506	1,639,969	1,578,035	1,028,330	823,523	593,963	482,837	636,140	787,957	933,640	1,122,385	1,117,770	12,366,055
2027	1,621,506	1,639,969	1,578,035	1,028,330	823,523	593,963	482,837	636,140	787,957	933,640	1,122,385	1,117,770	12,366,055
2026	1,621,506	1,639,969	1,578,035	1,028,330	823,523	593,963	482,837	636,140	787,957	933,640	1,122,385	1,117,770	12,366,055
2025	1,621,506	1,639,969	1,578,035	1,028,330	823,523	593,963	482,837	636,140	787,957	933,640	1,122,385	1,117,770	12,366,055
2024	1,251,215	1,081,228	1,070,354	651,376	576,987	472,441	385,508	542,978	610,118	594,374	1,122,385	1,117,770	9,476,734

Total Supply- Production A+ B (Formerly NRG) + Enbridge Gas + Production C (Lakeshore) + Production D (RNG)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2028	5,716,151	5,177,323	4,694,333	3,362,537	1,860,407	984,485	958,277	986,712	1,304,104	3,312,581	5,693,642	5,121,019	39,171,569
2027	5,643,324	5,123,663	4,628,047	3,289,000	1,818,630	954,865	928,167	957,183	1,274,993	3,251,348	5,581,262	5,068,110	38,518,594
2026	5,571,337	5,070,475	4,562,640	3,216,694	1,777,624	925,875	898,709	928,288	1,246,490	3,191,500	5,471,307	5,015,711	37,876,650
2025	5,500,241	5,017,807	4,498,151	3,145,641	1,737,398	897,518	869,902	900,028	1,218,597	3,133,028	5,363,760	4,963,849	37,245,919
2024	5,199,460	4,127,785	3,708,622	3,004,970	1,656,616	853,735	822,667	866,026	1,167,106	2,954,845	5,082,646	4,824,936	34,269,414

DEMAND FORECAST ANALYSIS

Total Demand

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2028	5,716,151	5,177,323	4,694,333	3,362,537	1,860,407	984,485	958,277	986,712	1,304,104	3,312,581	5,693,642	5,121,019	39,171,569
2027	5,643,324	5,123,663	4,628,047	3,289,000	1,818,630	954,865	928,167	957,183	1,274,993	3,251,348	5,581,262	5,068,110	38,518,594
2026	5,571,337	5,070,475	4,562,640	3,216,694	1,777,624	925,875	898,709	928,288	1,246,490	3,191,500	5,471,307	5,015,711	37,876,650
2025	5,500,241	5,017,807	4,498,151	3,145,641	1,737,398	897,518	869,902	900,028	1,218,597	3,133,028	5,363,760	4,963,849	37,245,919
2024	5,199,460	4,127,785	3,708,622	3,004,970	1,656,616	853,735	822,667	866,026	1,167,106	2,954,845	5,082,646	4,824,936	34,269,414

* for forecasting purposes e.g. 2023 onward, Enbridge gas supply is a formula based on total demand less Production A, B, C, and D

Appendix D – KEY TERMS

Balancing Gas: The volume of gas purchased for the purpose of clearing the Cumulative or Daily Operating Imbalance.

Baseload Gas: The minimum amount of natural gas delivered or contracted over a given period of time at a steady rate or price structure.

Cap and Trade: Ontario's cap and trade program is a market-based system that sets a hard cap on greenhouse gas emission. The cap is lowered over time and participants in the program must procure compliance instruments (e.g. emissions allowances, offset credits) to cover their annual emissions.

Clean Fuel Standard: A performance-based approach to reducing the carbon intensity of fossil fuels that would incent the use of a broad range of low carbon fuels, energy sources and technologies, such as electricity, hydrogen, and renewable fuels, including renewable natural gas. It would establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels, and would go beyond transportation fuels to include those used in industry and buildings.

Contract Customers: The maximum volume or quantity of gas that EPCOR is obligated to deliver in any one day to a customer under all services or, if the context so requires, a particular service at the consumption point.

Contract Demand ("CD"): Means the maximum volume or quantity of Gas that Union is obligated to deliver in any one Day to EPCOR under all Services or, if the context so requires, a particular Service at the Consumption Point

Contract Year: Means a period of twelve consecutive Months beginning on the Day of First Delivery and each anniversary date thereafter unless mutually agreed otherwise.

Dawn: Located southeast of Sarnia, Ontario, Dawn is referred to as a Hub as it represents the point where Enbridge supply, storage and transmission systems meet. A number of other pipeline systems (e.g. TCPL, Vector) are interconnected to Enbridge Gas' distribution system at Dawn.

Federal Carbon Pricing Program:	A Federal carbon pricing system implemented in Ontario, under the federal Greenhouse Gas Pollution Pricing Act.
Gas Day:	A period of 24 consecutive hours, beginning at 10:00 am ET. The reference date for any day shall be the calendar date upon which the twenty-four (24) hour period commences.
Gas Year:	A period of twelve (12) consecutive months usually beginning on November 1st and continuing until October 31st of the following year.
Heating Degree Day:	The number of degrees that a day's average temperature is below 18°C, which is the temperature below which buildings need to be heated.
Production A&B	Local gas production wells located within the EPCOR franchise area. These wells are owned by Lagasco and were formerly owned by NRG. The wells were sold at the time EPCOR Utilities Inc. purchased NRG distribution system on November 1, 2017and are currently under contract to EPCOR until September 30, 2020.
Production C	Local gas production wells located offshore in Lake Erie. EPCOR entered into a 5 year term contract effective October 3, 2019 in order to purchase firm gas deliveries from these wells
Production D	Local gas production from an Renewable Natural Gas (RNG) facility within the Aylmer Distribution Area. The gas is purchased as local supply, expected to start production in the fall of 2022
Rate 1– General Service Rate:	Includes residential, commercial and industrial customers that constitute majority of the customer base in the EPCOR natural gas system
Rate 2– Seasonal Service:	Includes mainly tobacco farming and curing customers (non-interruptible) that consume gas during the months of August and September. These customers are charged a different Delivery Charge for gas consumed between the months of April 1 through October 31 and November 1 through March 31.

Rate 3 – Special Large Volume Contract Rate: Includes customers who enter into a contract for the purchase or transportation of gas:

- for a minimum term of one year;
- that specifies a combined daily contracted demand for firm and interruptible service of at least 700 m^3;
- a qualifying annual volume of at least 113,000 m^3.

Rate 4 – General Service Peaking: Include primarily industrial customers whose operations can readily accept interruption and restoration of gas service within 24 hours' notice. These customers are charged a different Delivery Charge for gas consumed between the month of April 1 through December 31 and January 1 through March 31.

Rate 5 – Interruptible Peaking Contract Rate: Includes customers who enter into a contract for the purchase or transportation of gas:

- for a minimum term of one year;
- that specifies a daily contracted demand for interruptible service of at least 700 m3
- a qualifying annual volume of at least 50,000 m3.

Rate 6 - Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility: Rate specific to the IGPC ethanol production facility located in the Town of Aylmer.

WACOG: Weighted Average Cost of Gas.

Western Canadian Sedimentary Basin (WCSB): The Western Canadian Sedimentary Basin (WCSB) is a vast sedimentary basin underlying 1,400,000 square kilometres (540,000 sq mi) of Western Canada including south-western Manitoba, southern Saskatchewan, Alberta, north-eastern British Columbia and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east. This wedge is about 6 kilometres (3.7 mi) thick under the Rocky Mountains, but thins to zero at its eastern margins.

Appendix E – Power Advisory Weather Normalized Distribution System Throughput Forecast: 2024-2028




ENGLP Aylmer Weather Normalized Distribution System Throughput Forecast: 2024-2028

Prepared for: EPCOR Natural Gas Limited Partnership

May 28, 2024

Submitted by:
Andrew Blair
Power Advisory

POWER ADVISORY

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1. INTRODUCTION

This report outlines the results of, and methodology used to derive, the 2024 to 2028 weather normal throughput forecast (or "load forecast") prepared for EPCOR Natural Gas Limited Partnership ("ENGLP").

The methodology outlined in this report is consistent with the methodology used in ENGLP's last four load forecast updates[1] and is largely consistent with the methodology used in ENGLP's 2020 COS application (EB-2018-0336) and the methodology used by Natural Gas Resources Limited ("NRG") in previous rates applications.[2] Parties agreed to the results of the 2020 throughput forecast in settlement and the overall methodology was last approved by the OEB in EB-2010-0018. Alternate methods were tested but generally found to be inferior to the previously approved methodology.

The regression equations used to normalize and forecast ENGLP's weather sensitive load use monthly heating degree days as measured at Environment Canada's London CS weather station to take into account temperature sensitivity. This location is the closest weather station to ENGLP's service territory with strong historical weather data. ENGLP experiences peak loads in winter months, though certain rate classes are not weather sensitive. Environment Canada defines heating degree days as the difference between the average daily temperature and 18°C for each day. Heating degree days is 0 when the average temperature is above 18°C. Heating degree day data with alternate temperature thresholds other than 18°C wee considered, consistent with the OEB's electricity distributor load forecast filing requirements.

ENGLP serves six rate classes, R1 to R6, one of which (R1) contains three sub-classes: Residential, Commercial, and Industrial. Each R1 sub-class and the R3 class are weather-sensitive. Consumption of the R2, R4, R5, and R6 rate classes are not correlated to heating degree days. Consumption per customer forecasts for the R1 sub-classes use a baseload and excess consumption methodology to examine the impact of temperature on consumption. The R3 class's baseload consumption has fluctuated in historic years so the regression for this uses total consumption with a time trend.

Forecasts for non-weather sensitive classes are derived with average consumption per customer figures in recent years, consistent with previously approved forecasts. The number of years used on the average consumption per customer calculations is reassessed in each load

[1] The 2020-24 forecast update dated April 17, 2020, the 2021-25 forecast update dated April 23, 2021, the 2022-2026 forecast update dated April 23, 2022, and the 2023-2027 forecast update dated April 17, 2023.

[2] This report and the throughput forecast model were prepared by Andrew Blair, who prepared the throughput forecast used in EB-2018-0336 and subsequent throughput forecast updates for ENGLP as a member of Elenchus Research Associates. In February 2021 Power Advisory LLC and Elenchus Research Associates announced a strategic alliance between the two firms.

forecast to account for changes in consumption patterns over time. Consumption forecasts for non-weather sensitive classes is further described in Section 6 of this report.

In addition to the weather variables, other variables such as economic variables, time trend variable, number of days and number of working days in each month, number of customers, and month of year variables, have been examined for weather sensitive rate classes. A COVID variable and COVID/weather interaction variables were considered for weather-sensitive classes but found not to be statistically significant. More details on the individual class specifications are provided in the next section. ENGLP does not have a DSM plan so no adjustments were made to the class forecasts to account for DSM savings.

1.1 Summarized Results

The following table summarizes the historic and weather normalized consumption.

Table 1. Consumption Forecast by Class

Normal Forecast

	2022 Actual	2023 Actual	*2023 Normalized*	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
R1 Residential	18,760,439	17,466,767	*19,043,524*	19,394,143	19,778,416	20,165,775	20,556,215	20,949,733
R1 Industrial	2,377,452	3,013,707	*2,654,845*	2,579,897	2,686,373	2,795,837	2,908,361	3,024,023
R1 Commercial	6,163,726	5,823,050	*5,659,391*	6,119,454	6,193,869	6,268,637	6,343,760	6,419,235
R2 Seasonal	839,041	869,131	*869,131*	832,281	832,281	832,281	832,281	832,281
R3	1,551,993	1,335,618	1,389,910	3,943,038	4,518,036	4,495,600	4,475,300	4,456,801
R4	1,601,474	2,227,329	*2,227,329*	2,023,938	2,334,616	2,408,833	2,485,410	2,564,421
R5	585,954	980,160	*980,160*	647,586	647,586	647,586	647,586	647,586
R6	62,040,423	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852
Total	**93,920,502**	**97,061,614**	***98,170,143***	**100,886,188**	**102,337,027**	**102,960,400**	**103,594,765**	**104,239,931**

The following table summarizes the historic and forecast customer/connections for 2020-2028:

Table 2. Customer Forecast for 2022-2028

Customers

	2022 Actual	2023 Actual	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
R1 Residential	9,131	9,318	9,448	9,578	9,708	9,838	9,968
R1 Industrial	77	79	80	81	83	84	86
R1 Commercial	567	580	585	590	595	600	605
R2 Seasonal	51	51	50	50	50	50	50
R3	5	4	5	5	5	5	5
R4	42	43	45	46	48	49	51
R5	4	4	4	4	4	4	4
R6	1	1	1	1	1	1	1
Total	**9,878**	**10,080**	***10,218***	**10,355**	**10,494**	**10,631**	**10,770**

Forecasts of 2024 consumption by tier, for the classes billed based on volume tiers, is provided below.

Table 3. 2024 Consumption Forecast by Tier

2024 Tier Forecast

	Period	Tier 1	Tier 2	Tier 3	Total
R1 Residential		19,265,019	129,124		19,394,143
R1 Industrial		628,492	1,951,405		2,579,897
R1 Commercial		2,860,705	3,258,749		6,119,454
Seasonal	Apr-Oct	55,415	462,870	88,427	606,711
Seasonal	Nov-Mar	43,005	171,246	11,319	225,569
R4	Jan-Mar	31,712	6,420		38,132
R4	Apr-Dec	166,111	1,819,695		1,985,806

2. METHODOLOGY

Energy use for R1 Residential, R1 Industrial, R1 Commercial and R3 rate classes are forecast with multivariate regressions. Regressions were not selected for R2 Seasonal, R4, R5 and R6 rate classes as these classes do not exhibit sufficient sensitivity to the explanatory variables available for a statistical regression approach.

2.1 Consumption of Weather Sensitive Classes

Consumption of the three R1 rate classes are forecast using a base load and excess consumption method. Average monthly consumption per customer is first calculated for each class. The amounts are then reduced by the base load consumption, which is considered the average consumption in the summer months of July and August. The remaining consumption is considered the weather-sensitive load (or "excess" load). A baseline trend is applied to certain classes that have ongoing increasing consumption per customer that is not related to heating.

The excess load is regressed by the actual heating degree days in each month to determine the impact of cold weather on average consumption. A time-series (Prais-Winsten) regression is used to determine the coefficient, consistent with the methodology used in prior NRG throughput forecasts. A simple Ordinary Least Squares ("OLS") model is not appropriate as the errors exhibit a high level of autocorrelation (as demonstrated by Durbin-Watson statistics close to, or below, 1).

Alternate heating degree days data were also considered for each weather-sensitive class. Heating degree day figures were considered for a range of reference temperatures from 10°C to 20°C. Using alternate HDD temperatures considers the possibility that classes, on average, begin consuming natural gas for their heating load at temperatures other than 18°C.

Actual heating degree days are then multiplied by the coefficients and base load consumption is added back to determine the average predicted consumption in each month. Predicted total consumption of a class is determined by multiplying this sum by the actual number of customers.

The methodology is similar for the R3 class, but the base load is not removed before the regression. While the calculated base load consumption is generally consistent from year to year for the R1 classes, the base load appears to have declined in historic years.

To forecast 2024-2028 consumption, forecast heating degree days figures, as described in section 4, are used in place of actual heating degree days. Weather normalized consumption in historic years is determined by removing the deviations from average weather from consumption. This is done by multiplying the coefficients by the difference between actual and average heating degree days and applying the difference to actual consumption.

A set of interaction COVID/Weather variables were considered for the weather-sensitive classes but found to be not statistically significant. The values for this variable were set to 0 in all months before March 2020 and set equal to the applicable heating degree day variable for the months of March 2020 to December 2021. This variable was intended to capture potential incremental heating load for the Residential class, and reduced heating load for non-residential classes, resulting from people staying and working from home. This indicates that COVID did not have a material impact on heating load. A COVID variable, equal to 1 from March 2020 to December 2021 and 0 in all other months, was also tested and found not to be statistically significant.

2.2 Consumption of Non-Weather Sensitive Classes

Consumption of four rate classes (R2 Seasonal, R4, R5 and R6) are not weather-sensitive and do not exhibit sensitivity to the explanatory variables. Total and monthly volumes fluctuate from year to year, so a rolling average is used to forecast monthly consumption for these classes, with the exception of R4 in which a trend is also applied. The number of years used in the average calculations is explained in Section 6.

2.3 Customer Counts

Annual customer counts for 2024-2028 are forecast by applying a geometric mean annual growth rate to the 2023 average customer count for the R1 Industrial, R2 Seasonal and R4 rate classes. The R1 Residential forecast is based on 130 new attachments each year. The R1 Commercial forecast is based on 5 new customers per year. The customer counts for rate classes R3, R5, and R6 are unchanged through the 2024-2028 period except for known new customers in these rate classes. Calculations for each class are provided in section 5 and 6 of this report. Monthly customer counts are derived by applying equal percentage increases in each month such that the annual average of monthly forecasts is equal to the annual forecast.

2.4 Consumption Tiers

The R1 classes, R2 Seasonal Class, and R4 classes are billed according to consumption tiers (also known as volume blocks). Historic tiered data from January 2017 to November 2018 was used to derive weather-normal tiered forecasts. The allocation from total class throughput to tiered throughput has not been updated for this forecast.

The R1 classes are billed different rates on consumption above and below a 1,000 m^3 threshold. As these classes are weather-sensitive, the share of energy consumed in each tier is determined by adjusting actual consumption in each month for each individual customer to weather normal consumption. This method allows a class's forecast consumption to be consistent with the weather normalized total volume while maintaining the consumption profile of the rate classes. The weather-normalized consumption split between Tier 1 and Tier 2 in historic years is determined for each month and used to forecast the monthly splits in the forecast months. When two years of data was available, an average of the 2017 and 2018 splits was used. The R2 Seasonal and R4 classes are not weather-sensitive so the average of 2017 and 2018 tier splits were applied to total annual consumption.

3. CLASS SPECIFIC CONSUMPTION REGRESSIONS

3.1 R1 Residential

For the R1 Residential Class consumption the equation was estimated using 120 observations from 2014:01 to 2023:12. The natural logarithm of heating degree days at 18°C for the months of September to June were used, as measured at the London CS weather station as described in the introduction.

Several other variables were examined and found to not show a statistically significant relationship to energy usage. Those included alternate reference temperatures, economic indicators of full-time employment and GDP, days in each month, workdays in each month, a time trend, a COVID binary variable, and COVID/weather interaction variables.

A baseload trend was used to remove from 34.2m^3 in 2014 to 42.6m^3 in 2023 from the average consumption variable in each month. This amount is added back to the predicted values.

The following table outlines the resulting regression model:

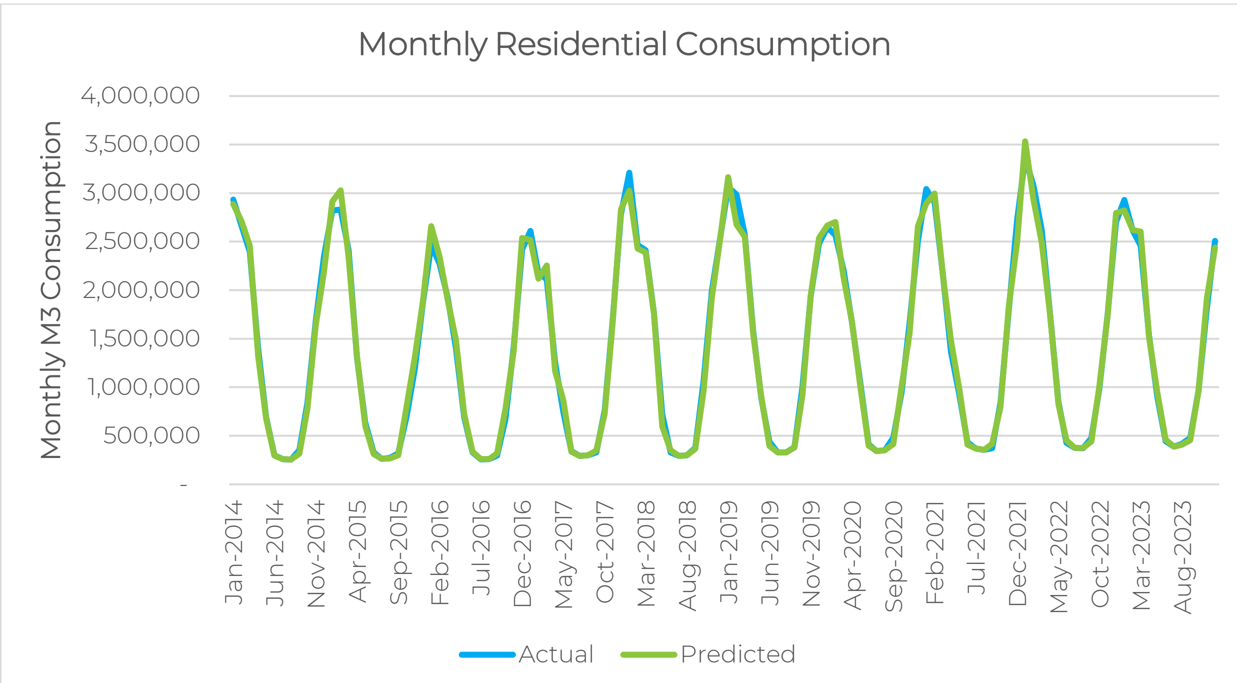
Table 4. R1 Residential Regression Model

Model 1: Prais-Winsten, using observations 2014:01-2023:12 (T = 120)				
Dependent variable: ExLNResAverageTrend				
rho = 0.046263				
	coefficient	std. error	t-ratio	p-value
const	0.13371	0.0599	2.23	2.8E-02
LNHDDJanuary18	0.85304	0.0156	54.61	5.2E-81
LNHDDFebruary18	0.85055	0.0159	53.59	3.8E-80
LNHDDMarch18	0.84640	0.0162	52.10	7.3E-79
LNHDDApril18	0.82457	0.0176	46.92	4.0E-74
LNHDDMay18	0.78817	0.0206	38.28	5.0E-65
LNHDDJune18	0.53653	0.0304	17.62	1.1E-33
LNHDDSeptember18	0.43248	0.0251	17.25	6.2E-33
LNHDDOctober18	0.74184	0.0188	39.38	2.8E-66
LNHDDNovember18	0.81395	0.0169	48.14	2.8E-75
LNHDDDecember18	0.85124	0.0162	52.61	2.6E-79
Statistics based on the rho-differenced data				
Sum squared resid	7.53328	S.E. of regression		0.263
R-squared	0.98525	Adjusted R-squared		0.98389
F(10, 109)	675.834	P-value(F)		0.00000
rho	0.00136	Durbin-Watson		1.99706

In the above table, and all regression results tables in the section, LN denotes natural logarithm, HDD denotes heating degree days, the month name denotes a dummy variable representing 1 in the labeled month and 0 in all other months, and the '18' denotes the reference HDD temperature of 18°C. The values within the LNHDDJanuary variable, for example, includes the natural logarithm of the number of heating degree days for each January, and 0 in all other months. The label for the dependent variable includes "Ex" denoting the values of this variable are the excess consumption above the class's base load.

Actual consumption and predicted consumption using the above model coefficients are compared in Figure 1.

Figure 1. R1 Residential Predicted vs Actual Observations



Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.5%. The MAPE calculated monthly over the period is 4.1%.

Table 5. R1 Residential Model Error

	Residential		Absolute
Year	Actual	Predicted	Error (%)
2014	16,127,158	15,785,716	2.1%
2015	14,948,329	15,337,184	2.6%
2016	14,417,053	14,993,968	4.0%
2017	15,400,135	15,417,551	0.1%
2018	17,442,260	16,900,849	3.1%
2019	18,000,452	17,699,947	1.7%
2020	16,837,081	16,909,964	0.4%
2021	17,299,257	17,196,811	0.6%
2022	18,760,439	18,717,450	0.2%
2023	17,466,767	17,549,250	0.5%
Total	**166,698,932**	**166,508,692**	**0.1%**
Mean Absolute Percentage Error (Annual)			1.5%
Mean Absolute Percentage Error (Monthly)			4.1%

3.2 R1 Industrial

For the R1 Industrial Class consumption the equation was estimated using 120 observations from 2014:01 to 2023:12. The natural logarithm of heating degree days at 16°C for the months from August to May were used, as measured at the London CS weather station. Consumption in November and December 2023 was anomalously high due to high crop yields. The crop yields, and associated grain drying load, is uncharacteristic of typical class consumption and ENGLP's expectations of the class's load in the future so an alternate version of the regression was run using November and December 2022 consumption per customer in place of November and December 2023 volumes. Absent this adjustment, heating degree days in November and December would overstate the influence of weather on class loads.

Several other variables were examined and found to not show a statistically significant relationship to energy usage. Those included alternate reference temperatures, economic indicators of full-time employment and GDP, days in each month, workdays in each month, and a time trend.

A baseload trend was used to remove from 523.9m^3 in 2014 to 1,024.9m^3 in 2023 from the average consumption variable in each month. This amount is added back to the predicted values.

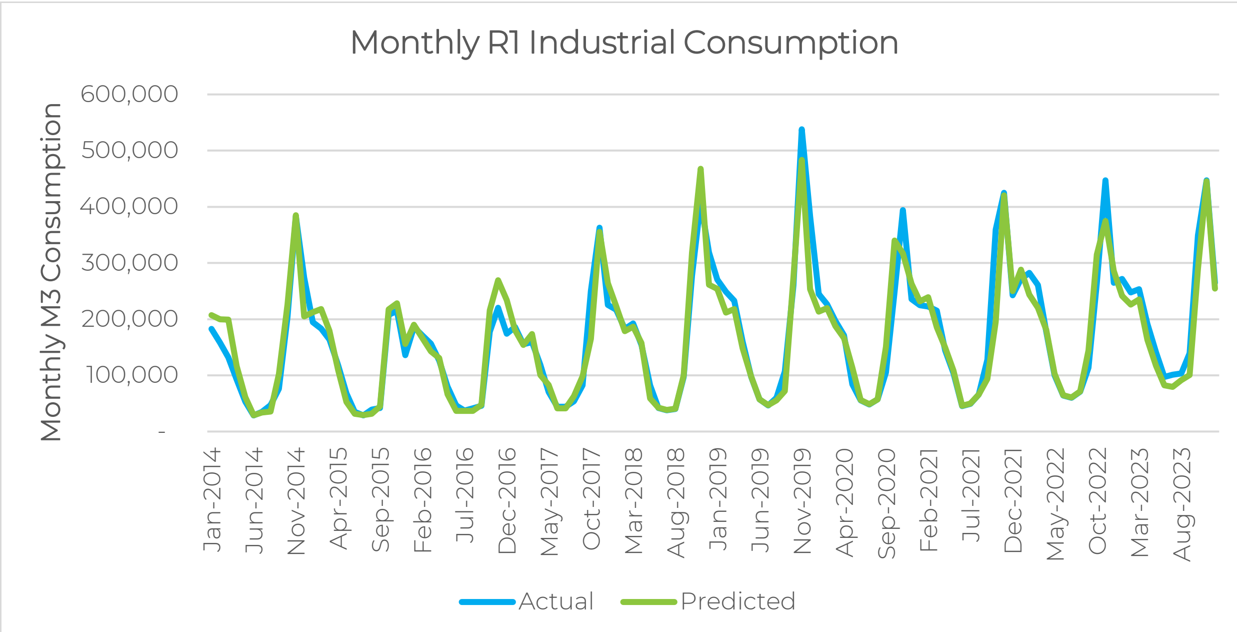
The following table outlines the resulting regression model:

Table 6. R1 Industrial Regression Model

Model 3: Prais-Winsten, using observations 2014:01-2023:12 (T = 120)				
Dependent variable: ExLNR1AverageTrend				
rho = 0.341842				
	coefficient	std. error	t-ratio	p-value
const	1.874	0.256	7.308	4.76E-11
LNHDDJanuary16	0.917	0.066	13.806	1.11E-25
LNHDDFebruary16	0.913	0.068	13.522	4.69E-25
LNHDDMarch16	0.926	0.069	13.455	6.57E-25
LNHDDApril16	0.935	0.073	12.784	2.03E-23
LNHDDMay16	0.927	0.080	11.606	9.23E-21
LNHDDAugust16	1.984	0.388	5.110	1.38E-06
LNHDDSeptember16	1.328	0.116	11.449	2.09E-20
LNHDDOctober16	1.176	0.081	14.599	2.10E-27
LNHDDNovember16	1.103	0.072	15.279	7.37E-29
LNHDDDecember16	0.963	0.069	13.982	4.58E-26
Statistics based on the rho-differenced data				
Sum squared resid	116.6562	S.E. of regression		1.0345
R-squared	0.8626	Adjusted R-squared		0.8499
F(10, 109)	41.6800	P-value(F)		1.01E-32
rho	-0.0328	Durbin-Watson		2.0654

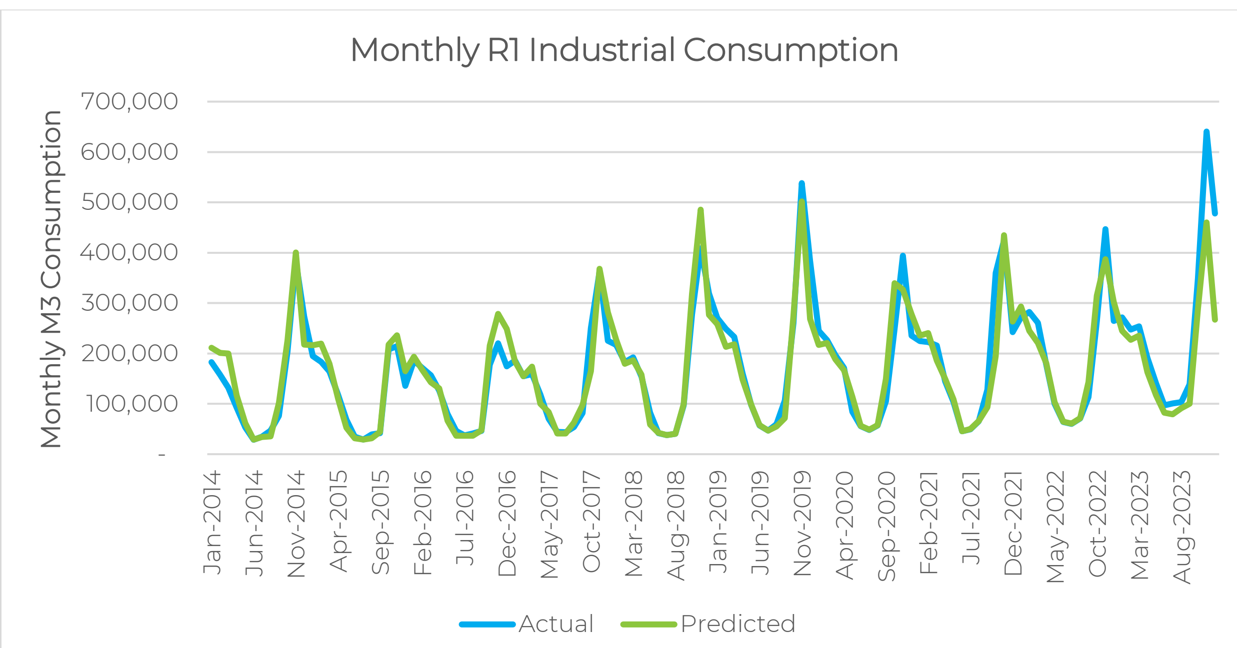
Actual consumption and predicted consumption using the above model coefficients are compared in Figure 2.

Figure 2. R1 Industrial Predicted vs Actual Observations
(with November and December 2023 actuals adjustment)



For reference, the predicted volumes without adjusting for November and December 2023 volumes is provided below.

Figure 3. R1 Industrial Predicted vs Actual Observations



Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 6.0%. The MAPE calculated monthly over the period is 12.6%.

Table 7. R1 Industrial Model Error

	R1 Industrial		Absolute
Year	Actual	Predicted	Error (%)
2014	1,666,209	1,799,840	8.0%
2015	1,430,900	1,511,044	5.6%
2016	1,462,707	1,573,628	7.6%
2017	1,752,123	1,719,182	1.9%
2018	2,050,371	2,072,474	1.1%
2019	2,461,420	2,173,569	11.7%
2020	2,067,358	2,133,667	3.2%
2021	2,226,121	2,034,437	8.6%
2022	2,377,452	2,352,264	1.1%
2023	2,606,905	2,325,035	10.8%
Total	**20,101,567**	**19,695,140**	**2.0%**
Mean Absolute Percentage Error (Annual)			6.0%
Mean Absolute Percentage Error (Monthly)			12.6%

3.3 R1 Commercial

For the R1 Commercial Class consumption the equation was estimated using 120 observations from 2014:01 to 2023:12. The natural logarithm of heating degree days at 18°C for the months from September to June were used, as measured at the London CS weather station.

Several other variables were examined and found to not show a statistically significant relationship to energy usage. Those included alternate reference temperatures, economic indicators of full-time employment and GDP, days in each month, workdays in each month, and a time trend.

A baseload trend was used to remove from 198.0m^3 in 2014 to 239.9m^3 in 2023 from the average consumption variable in each month. This amount is added back to the predicted values.

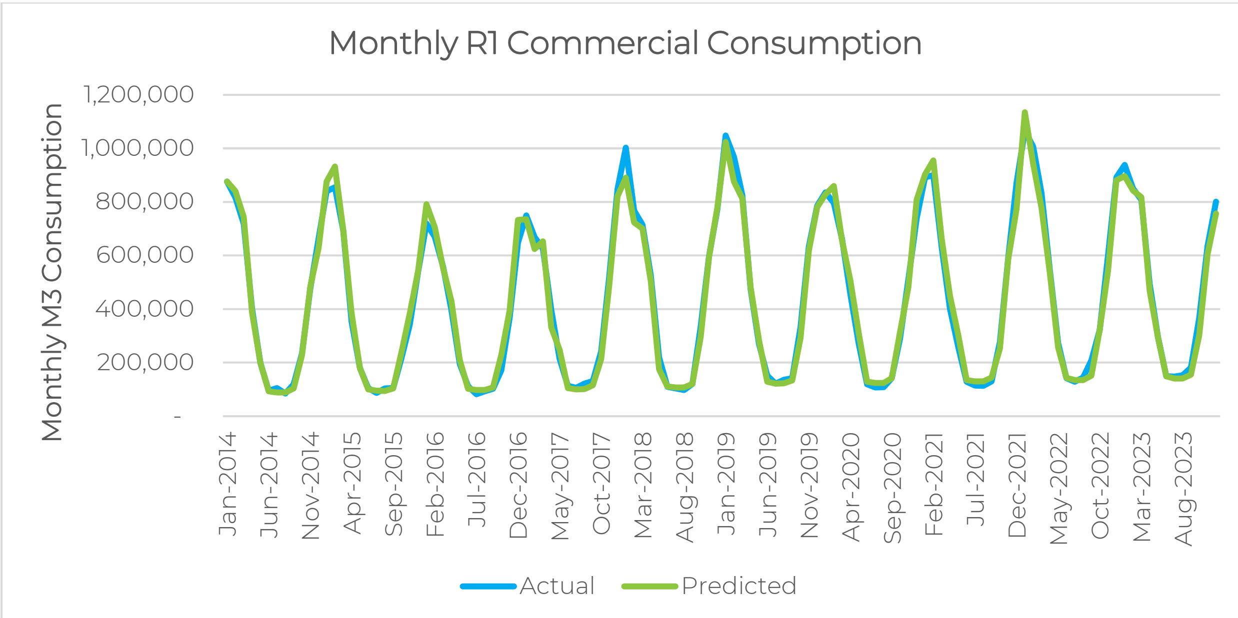
The following table outlines the resulting regression model:

Table 8. R1 Commercial Regression Model

Model 3: Prais-Winsten, using observations 2014:01-2023:12 (T = 120)				
Dependent variable: ExLNComAverageTrend				
rho = 0.315543				
	coefficient	std. error	t-ratio	p-value
const	1.31720	0.2201	5.98	2.8E-08
LNHDDJanuary18	0.91950	0.0532	17.29	5.2E-33
LNHDDFebruary18	0.92001	0.0542	16.99	2.1E-32
LNHDDMarch18	0.91238	0.0553	16.50	2.1E-31
LNHDDApril18	0.88818	0.0593	14.99	3.1E-28
LNHDDMay18	0.85187	0.0674	12.63	4.5E-23
LNHDDJune18	0.40485	0.0904	4.48	1.8E-05
LNHDDSeptember18	0.51957	0.0744	6.98	2.4E-10
LNHDDOctober18	0.80927	0.0617	13.11	3.9E-24
LNHDDNovember18	0.88207	0.0570	15.47	3.0E-29
LNHDDDecember18	0.91448	0.0549	16.66	9.9E-32
Statistics based on the rho-differenced data				
Sum squared resid	73.03951	S.E. of regression		0.819
R-squared	0.89337	Adjusted R-squared		0.88358
F(10, 109)	54.32262	P-value(F)		0.00000
rho	-0.05334	Durbin-Watson		2.10666

Actual consumption and predicted consumption using the above model coefficients are compared in Figure 4.

Figure 4. R1 Commercial Predicted vs Actual Observations



Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 4.1%. The MAPE calculated monthly over the period is 7.1%.

Table 9. R1 Commercial Model Error

Year	R1 Commercial Actual	Predicted	Absolute Error (%)
2014	4,788,282	4,757,288	0.6%
2015	4,420,443	4,624,892	4.6%
2016	4,117,374	4,451,110	8.1%
2017	4,734,213	4,535,876	4.2%
2018	5,363,288	5,107,807	4.8%
2019	5,890,482	5,675,491	3.6%
2020	5,028,438	5,276,100	4.9%
2021	5,306,940	5,419,823	2.1%
2022	6,163,726	5,961,613	3.3%
2023	5,823,050	5,570,130	4.3%
Total	**51,636,234**	**51,380,129**	**0.5%**
Mean Absolute Percentage Error (Annual)			4.1%
Mean Absolute Percentage Error (Monthly)			7.1%

3.4 R3

For the R3 Class consumption the equation was estimated using 120 observations from 2014:01 to 2023:12. The natural logarithm of heating degree days at 20°C for the months from September to May were used, as measured at the London CS weather station. A natural log of a time trend is also included, beginning at ln(10) in January 2014 (increasing to ln(121) in December 2023) is used as this class exhibits declining average consumption over time.

A dummy variable for June was included as consumption in June was typically greater than what was expected based on the weather in that month. A dummy variable for the shoulder months of March, April, May, September, October, and November was also used to reflect lower consumption in those months than could be explained by heating degree days.

Several other variables were examined and found to not show a statistically significant relationship to energy usage. Those included alternate weather variables, economic indicators of full-time employment and GDP, days in each month, and workdays in each month.

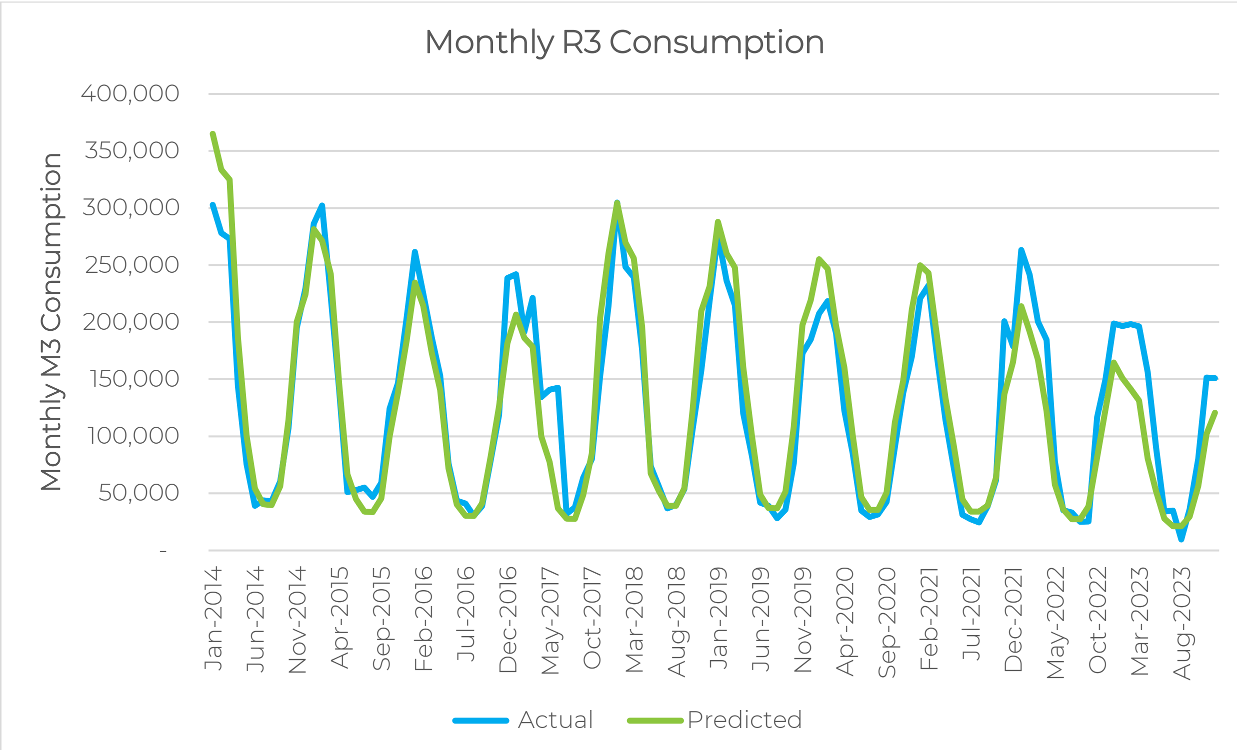
The following table outlines the resulting regression model:

Table 10. R3 Regression Model

Model 4: Prais-Winsten, using observations 2014:01-2023:12 (T = 120)				
Dependent variable: LNContractR3Average				
rho = 0.460215				
	coefficient	std. error	t-ratio	p-value
const	10.10331	0.2616	38.63	1.2E-64
LNHDDJanuary20	0.30081	0.0167	18.06	2.9E-34
LNHDDFebruary20	0.29498	0.0170	17.37	6.3E-33
LNHDDMarch20	0.71034	0.1592	4.46	2.0E-05
LNHDDApril20	0.69684	0.1703	4.09	8.3E-05
LNHDDMay20	0.68227	0.1935	3.53	6.2E-04
LNHDDSeptember20	0.07438	0.0186	3.99	1.2E-04
LNHDDOctober20	0.66846	0.1804	3.71	3.4E-04
LNHDDNovember20	0.69591	0.1650	4.22	5.2E-05
LNHDDDecember20	0.27867	0.0170	16.42	5.2E-31
lnTrend	-0.31692	0.0613	-5.17	1.1E-06
Shoulder	-2.73990	1.0214	-2.68	8.5E-03
June	0.27118	0.0855	3.17	2.0E-03
Statistics based on the rho-differenced data				
Sum squared resid	6.15956	S.E. of regression		0.23993
R-squared	0.92379	Adjusted R-squared		0.91525
F(12, 107)	74.27188	P-value(F)		3.56E-46
rho	-0.07971	Durbin-Watson		2.15382

Actual consumption and predicted consumption using the above model coefficients are compared in Figure 5.

Figure 5. R3 Predicted vs Actual Observations



Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 10.6%. The MAPE calculated monthly over the period is 22.6%. The MAPEs are relatively high for this class but more variance can be expected in a class with only 4 to 6 customers.

Table 11. R3 Model Error

	R3		Absolute
Year	Actual	Predicted	Error (%)
2014	1,792,006	2,040,828	13.9%
2015	1,692,328	1,588,739	6.1%
2016	1,492,346	1,366,848	8.4%
2017	1,653,466	1,438,890	13.0%
2018	1,711,013	1,842,900	7.7%
2019	1,510,164	1,756,983	16.3%
2020	1,361,184	1,600,908	17.6%
2021	1,372,372	1,423,148	3.7%
2022	1,551,993	1,251,421	19.4%
2023	1,335,618	935,681	29.9%
Total	**15,472,490**	**15,246,345**	**1.5%**
Mean Absolute Percentage Error (Annual)			13.6%
Mean Absolute Percentage Error (Monthly)			22.2%

4. WEATHER NORMALIZATION

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells "average" out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. While there are several different approaches to determining an appropriate weather normal, ENGLP has adopted the 10-year trend of 10-year monthly degree day averages.

Various methods were analysed to determine the most appropriate methodology to forecast monthly heating degree days from 2024 to 2028. A 5-year average, 10-year average, 20-year trend, 5-year weighted average, 10-year trend of 5 year averages, 10-year trend of 10-year averages, and the midpoint of the 10-year average and 20-year trend were considered.

Data from 1984 to 2023 was used to evaluate each method's predicted heating degree days against the actual heating degree days for each month since January 2004. Data from Environment Canada's London Airport weather station was used for the period from 1984 to 2002. London Airport's temperature data is only provided until 2002, which is approximately when temperature data for London CS begins. Data from the London A weather station (another London Airport weather station with temperature data as of March 2012) is used in place of London CS when data from that station is unavailable.

Each method was ranked according to the magnitude of the deviations between predicted and actual heating degree days, with 1 being the closest predicted value and 7 being the furthest. The rankings were done on monthly and annual bases. The following table shows the annual rankings, average annual and monthly rankings, and variance of the deviations on monthly and annual bases.

Table 12. HDD Rankings and Variance

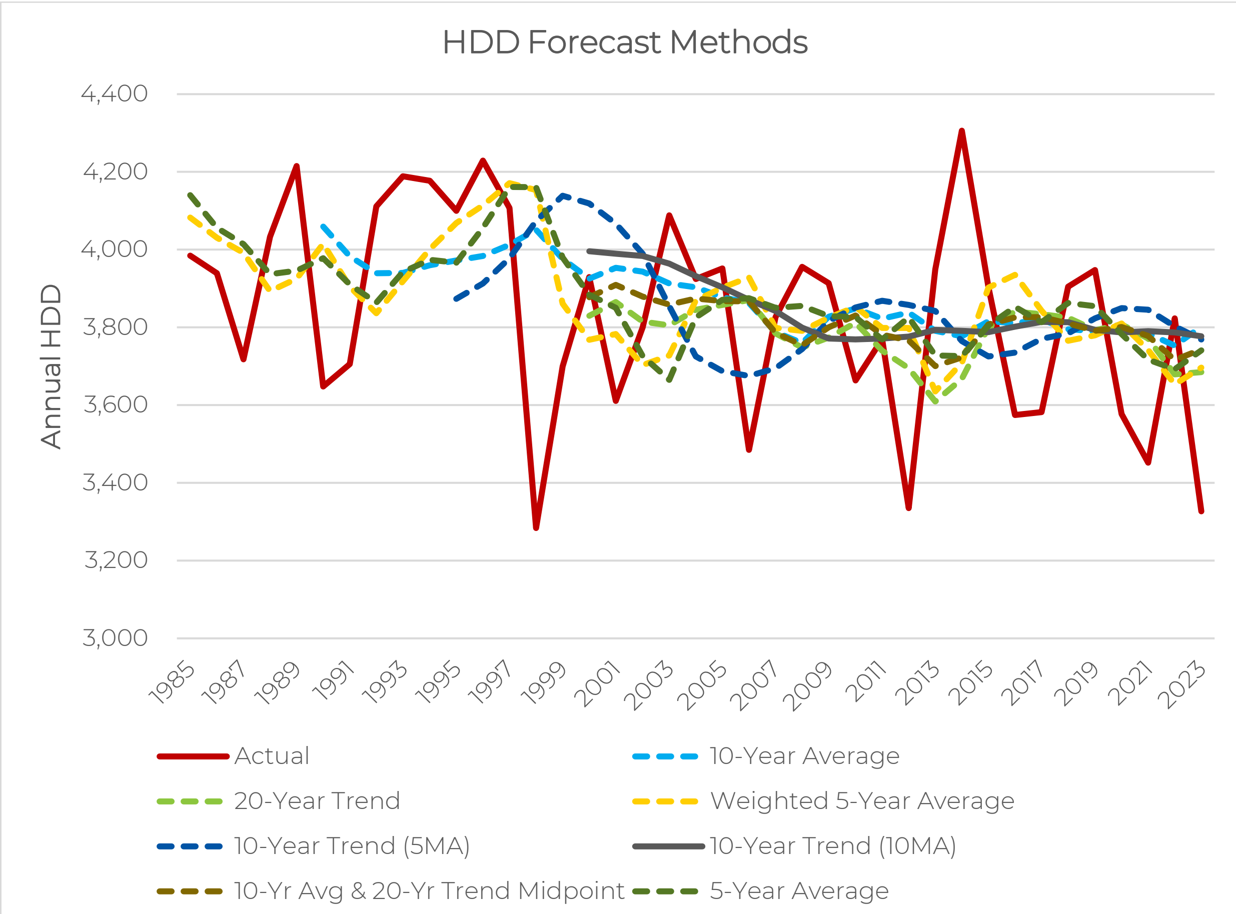
Year	5-Year Average	10-Year Average	20-Year Trend	Weighted 5-Year Average	10-Year Trend (5MA)	10-Year Trend (10MA)	10-Yr Avg & 20-Yr Trend Midpoint
2004	6	2	5	4	7	1	3
2005	4	3	6	2	7	1	5
2006	6	2	4	7	1	5	3
2007	2	4	6	3	7	1	5
2008	1	4	6	3	7	2	5
2009	1	2	6	3	4	7	5
2010	3	5	2	7	6	1	4
2011	1	6	5	4	7	2	3
2012	5	6	1	4	7	3	2
2013	4	3	7	6	1	2	5
2014	4	2	7	6	3	1	5
2015	4	2	5	1	7	6	3
2016	6	3	5	7	1	2	4
2017	2	4	6	7	1	3	5
2018	1	5	2	7	6	3	4
2019	5	7	1	4	2	6	3
2020	1	3	5	6	7	2	4
2021	1	5	3	2	7	6	4
2022	5	3	6	7	1	2	4
2023	3	7	1	2	5	6	4
Average Rank							
Monthly	3.99	3.85	4.19	4.23	3.96	3.85	3.93
Annual	3.25	3.90	4.45	4.60	4.70	3.10	4.00
Variance between Predicted and Actual							
Monthly	3,977	3,642	4,047	4,301	3,886	3,586	3,805
Annual	65,664	67,132	72,586	76,701	72,477	60,791	68,958

The rankings and variance analysis reveals that the 10-year trend of the 10-year average is the best methodology for predicting future heating degree days. On a monthly and annual basis, the predicted heating degree days using this methodology is closest to actual heating degree days and the deviations from actual weather have the lowest variance among the methods analysed.

For clarity, the 10-year trend of the 10-year moving average is the annualized trend of one 10-year period to the next 10-year period. For example, the 2004 predicted value uses the trend from the average heating degree days from 1984 and 1993 to the average from 1994 and 2003.

This method is the best predictive method as it accounts for trends in heating degree days over time without being over-reliant on data of any one year. Simple averages do not consider weather trends over time and typical trend forecasts can be significantly impacted by single data points.

Figure 6. Weather Forecast for Various Methods



In Figure 6, actual HDD and the selected 10-year trend of 10-year moving averages metric are in solid lines and the dotted lines represent the other methods considered.

The monthly predicted and forecast heating degree days are detailed in the following tables for heating degree days at 18°C.

Table 13. Forecast HDD 18°C

18°C	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total	Actual
2014	720	661	543	307	156	31	6	11	68	253	406	633	3,794	4,306
2015	719	667	545	310	151	29	6	10	72	250	416	630	3,804	3,904
2016	722	677	548	313	144	28	7	10	74	249	422	618	3,813	3,575
2017	727	682	547	318	138	28	7	11	74	246	424	611	3,813	3,582
2018	727	676	547	319	133	29	7	11	74	243	424	608	3,798	3,905
2019	732	668	547	325	126	29	7	11	74	241	427	604	3,792	3,947
2020	733	662	549	332	124	29	6	10	73	239	435	601	3,793	3,577
2021	729	655	552	341	126	29	6	10	71	239	437	593	3,789	3,452
2022	722	650	550	348	132	29	5	10	68	237	442	588	3,780	3,829
2023	722	649	552	354	137	29	4	9	65	236	442	584	3,783	3,327
2024	717	639	551	359	143	29	3	9	59	231	443	572	3,754	
2025	715	636	551	363	144	29	3	9	57	229	444	567	3,747	
2026	714	632	551	367	145	29	2	9	55	228	446	563	3,741	
2027	713	629	551	372	146	29	2	8	53	226	448	558	3,734	
2028	712	625	551	376	147	28	1	8	52	224	450	553	3,727	

5. WEATHER-NORMALIZED CLASS FORECASTS

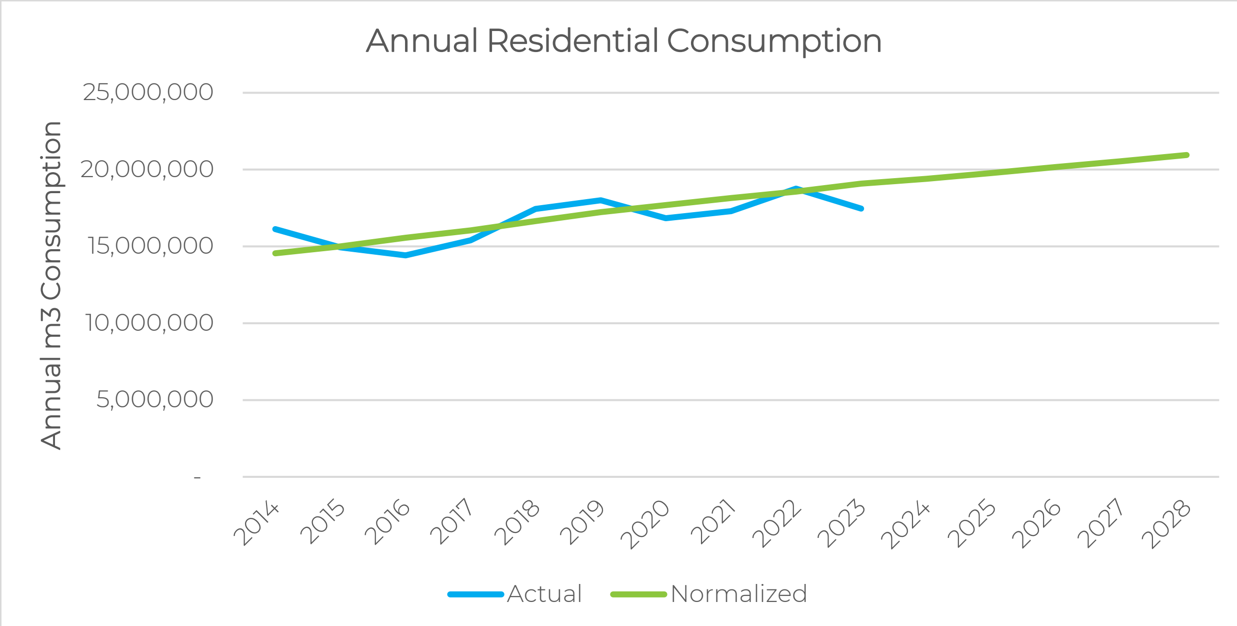
5.1 R1 Residential

Incorporating the normalized and forecast heating degree days the following weather corrected consumption and forecast values are calculated:

Table 14. Actual vs Normalized R1 Residential

R1 Residential						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2014	7,470	2,162	16,150,603	16,127,158	1,950	14,551,718
2015	7,726	1,938	14,974,492	14,948,329	1,942	15,001,278
2016	7,956	1,813	14,425,323	14,417,053	1,959	15,572,288
2017	8,110	1,892	15,347,218	15,400,135	1,973	16,047,138
2018	8,400	2,075	17,426,321	17,442,260	1,982	16,658,300
2019	8,657	2,083	18,035,211	18,000,452	1,994	17,230,177
2020	8,805	1,911	16,828,031	16,837,081	2,009	17,698,028
2021	8,983	1,927	17,311,669	17,299,257	2,022	18,146,276
2022	9,131	2,055	18,768,709	18,760,439	2,033	18,557,330
2023	9,318	1,875	17,474,225	17,466,767	2,049	19,083,780
2024	9,448				2,055	19,394,143
2025	9,578				2,067	19,778,416
2026	9,708				2,079	20,165,775
2027	9,838				2,092	20,556,215
2028	9,968				2,104	20,949,733

Figure 7. Actual vs Normalized R1 Residential



A tiered forecast was produced using actual individual customer data adjusted to weather-normal consumption.

Table 15. Forecasted R1 Residential Tiered Consumption

	R1 Residential		
	Tier 1	Tier 2	Total
2022	18,633,590	126,849	18,760,439
2023	18,914,526	128,998	17,466,767
2024	19,265,019	129,124	19,394,143
2025	19,647,131	131,285	19,778,416
2026	20,032,319	133,456	20,165,775
2027	20,420,578	135,637	20,556,215
2028	20,811,906	137,828	20,949,733

The R1 Residential customer count is forecast to increase by 130 customers per year through the 2024-2028 period.

Table 16. Forecasted R1 Residential Customer Count

Year	Residential Customers	Percent of Prior Year
2014	7,470	
2015	7,726	103.4%
2016	7,956	103.0%
2017	8,110	101.9%
2018	8,400	103.6%
2019	8,657	103.1%
2020	8,805	101.7%
2021	8,983	102.0%
2022	9,131	101.6%
2023	9,318	102.0%
2024	9,448	101.4%
2025	9,578	101.4%
2026	9,708	101.4%
2027	9,838	101.4%
2028	9,968	101.4%

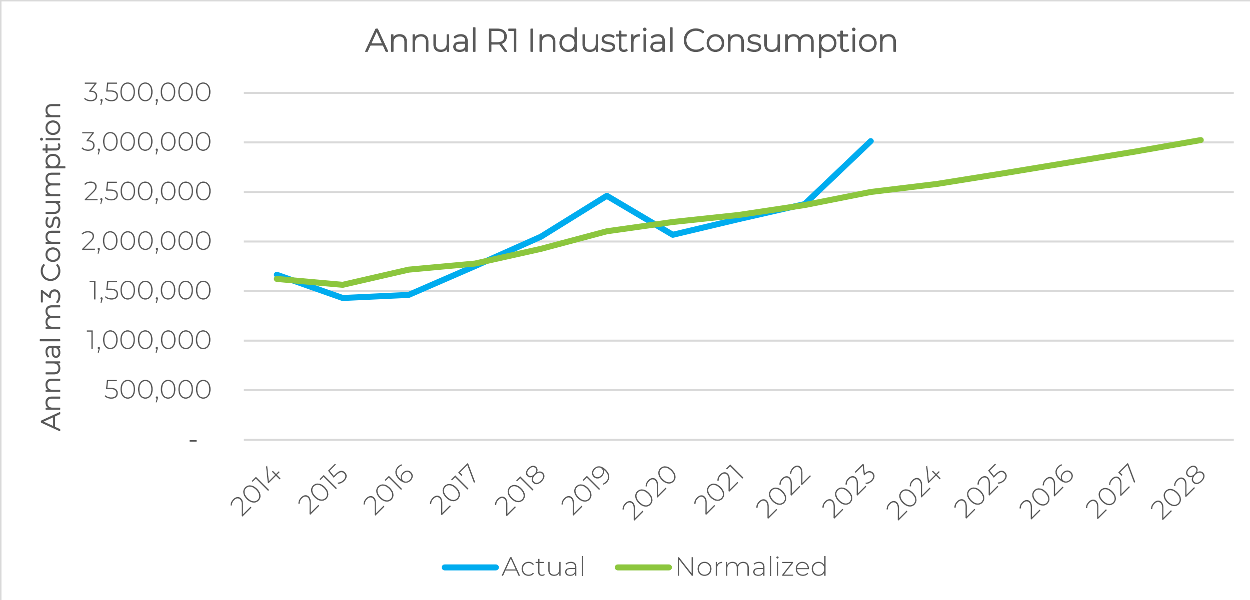
5.2 R1 Industrial

Incorporating the normalized and forecast heating degree days the following weather corrected consumption and forecast values are calculated:

Table 17. Actual vs Normalized R1 Industrial

R1 Industrial						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2014	63	26,306	1,659,456	1,666,209	25,679	1,622,173
2015	62	23,186	1,439,435	1,430,900	25,414	1,564,050
2016	65	22,433	1,461,881	1,462,707	26,264	1,716,903
2017	66	26,620	1,752,499	1,752,123	27,027	1,778,490
2018	68	29,425	2,005,771	2,050,371	27,741	1,927,753
2019	73	33,281	2,440,611	2,461,420	28,530	2,105,215
2020	75	27,629	2,067,592	2,067,358	29,345	2,196,313
2021	75	29,576	2,215,758	2,226,121	30,141	2,267,564
2022	77	31,039	2,384,840	2,377,452	30,893	2,367,134
2023	79	38,124	2,999,059	3,013,707	31,654	2,499,328
2024	80				32,207	2,579,897
2025	81				32,954	2,686,373
2026	83				33,700	2,795,837
2027	84				34,447	2,908,361
2028	86				35,195	3,024,023

Figure 8. Actual vs Normalized R1 Industrial



A tiered forecast was produced using actual individual customer data adjusted to weather-normal consumption.

Table 18. Forecasted R1 Industrial Tiered Consumption

	R1 Industrial		
	Tier 1	Tier 2	Total
2022	561,145	1,816,307	2,377,452
2023	798,103	2,541,872	3,013,707
2024	628,492	1,951,405	2,579,897
2025	658,242	2,028,131	2,686,373
2026	688,855	2,106,981	2,795,837
2027	720,354	2,188,007	2,908,361
2028	752,761	2,271,262	3,024,023

The Geometric mean of the annual growth from 2019 to 2023 was used to forecast the growth rate from 2024 to 2028. The number of customers in this class grew at a higher rate from 2014 to 2019 than since 2019 so the growth rates from these years was excluded as they do not reflect the current customer growth trend.

The following table includes the customer Actual / Forecast customer count on this basis:

Table 19. Forecasted R1 Industrial Customer Count

Year	R1 Industrial Customers	Percent of Prior Year
2014	63	
2015	62	98.4%
2016	65	105.0%
2017	66	101.0%
2018	68	103.5%
2019	73	107.6%
2020	75	102.0%
2021	75	100.1%
2022	77	102.6%
2023	79	102.4%
2024	80	101.8%
2025	81	101.8%
2026	83	101.8%
2027	84	101.8%
2028	86	101.8%

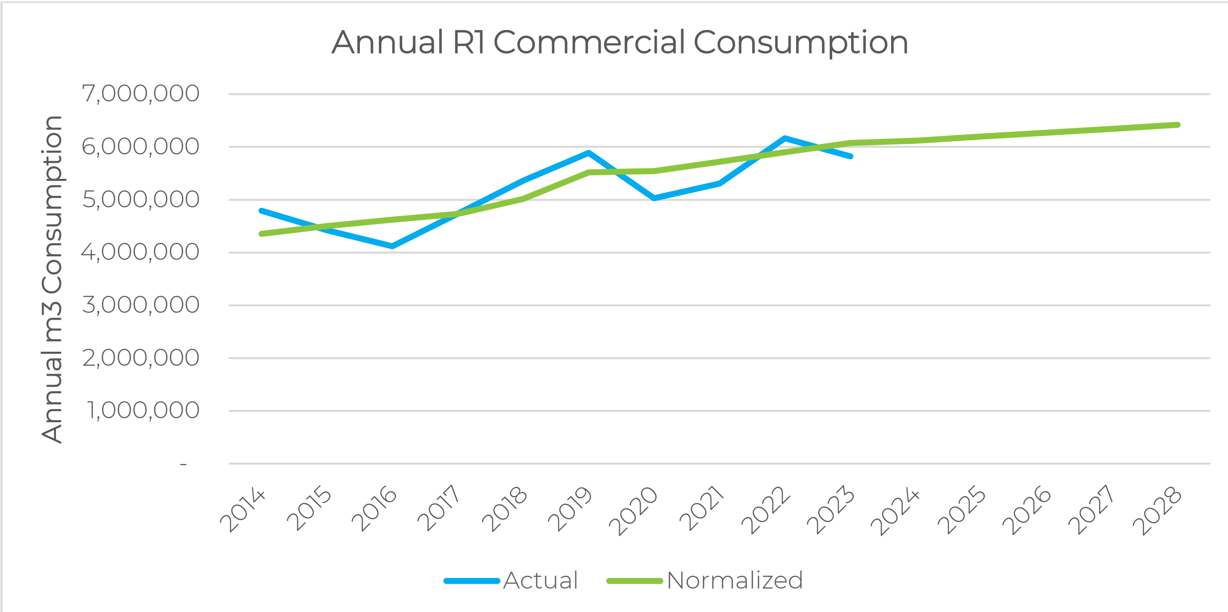
5.3 R1 Commercial

Incorporating the normalized and forecast heating degree days the following weather corrected consumption and forecast values are calculated:

Table 20. Actual vs Normalized R1 Commercial

R1 Commercial						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2014	437	10,964	4,795,706	4,788,282	9,965	4,352,936
2015	445	9,935	4,421,983	4,420,443	10,109	4,500,547
2016	453	9,065	4,102,131	4,117,374	10,172	4,619,881
2017	462	10,219	4,716,893	4,734,213	10,222	4,732,258
2018	487	10,958	5,332,657	5,363,288	10,242	5,017,159
2019	536	10,970	5,880,685	5,890,482	10,279	5,519,688
2020	535	9,378	5,017,149	5,028,438	10,331	5,539,888
2021	552	9,615	5,309,753	5,306,940	10,371	5,719,789
2022	567	10,869	6,157,559	6,163,726	10,402	5,899,372
2023	580	10,024	5,817,409	5,823,050	10,459	6,076,900
2024	585				10,462	6,119,454
2025	590				10,499	6,193,869
2026	595				10,536	6,268,637
2027	600				10,574	6,343,760
2028	605				10,611	6,419,235

Figure 9. Actual vs Normalized R1 Commercial



A tiered forecast was produced using actual individual customer data adjusted to weather-normal consumption.

Table 21. Forecasted R1 Commercial Tiered Consumption

	R1 Commercial		
	Tier 1	Tier 2	Total
2022	2,874,696	3,289,030	6,163,726
2023	3,161,469	3,522,151	5,823,050
2024	2,860,705	3,258,749	6,119,454
2025	2,898,065	3,295,803	6,193,869
2026	2,935,634	3,333,004	6,268,637
2027	2,973,410	3,370,349	6,343,760
2028	3,011,395	3,407,840	6,419,235

The Geometric mean of the annual growth from 2014 to 2023 was used to forecast the growth rate from 2024 to 2028.The following table includes the customer Actual / Forecast customer count on this basis:

Table 22. Forecasted R1 Commercial Customer Count

Year	R1 Commercial Customers	Percent of Prior Year
2014	33	
2015	34	102.5%
2016	35	103.7%
2017	36	101.4%
2018	37	101.9%
2019	37	100.5%
2020	40	110.2%
2021	41	100.6%
2022	42	102.5%
2023	43	104.2%
2024	45	103.2%
2025	46	103.2%
2026	48	103.2%
2027	49	103.2%
2028	51	103.2%

5.4 R3

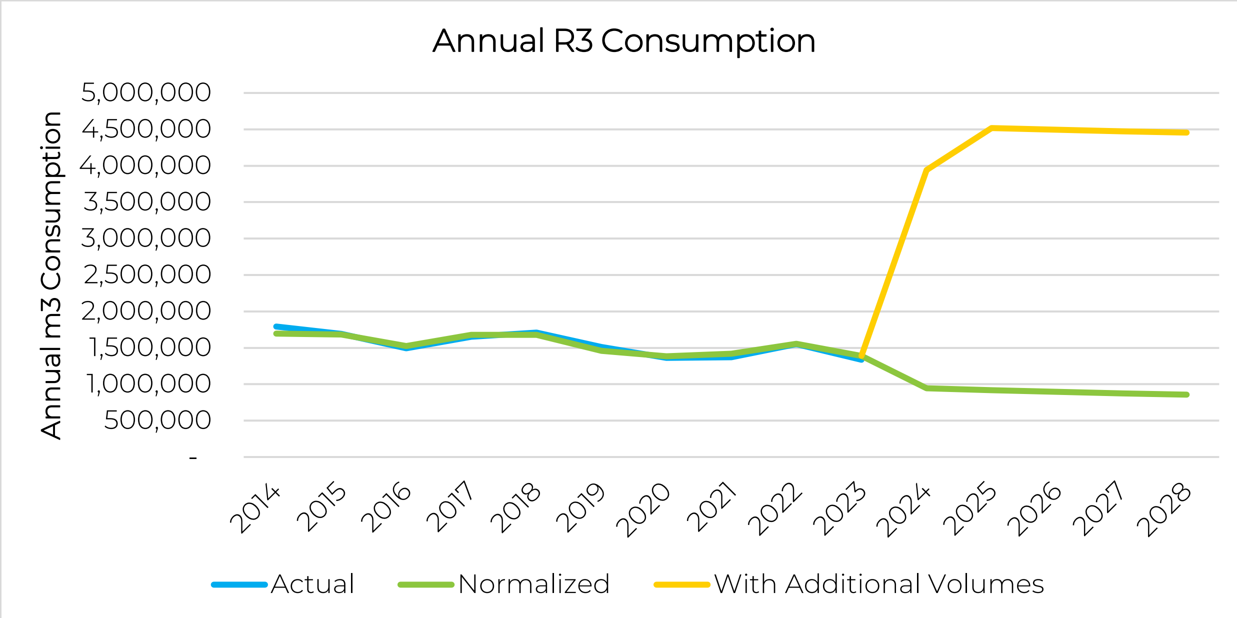
The R3 rate class is gaining one large customer with forecast volumes of 3,000,000m^3 in 2024 and 3,600,000m^3 annual volumes annually beginning in 2025. The R3 forecast is based on forecast volumes of the four customers in the class plus the additional volumes of this customer. Incorporating the normalized and forecast heating degree days, continuing time trend and calendar dummy variables, the following weather corrected consumption and forecast values are calculated:

Table 23. Actual vs Normalized R3

R3							
Year	Cust.	Consumption		Normalized			
		Per Customer	Total / Actual	Per Customer	Total	Additional Volumes	Total w/ Additional
2014	4	448,002	1,792,006	423,716	1,694,865		
2015	4	423,082	1,692,328	420,181	1,680,722		
2016	4	373,087	1,492,346	381,386	1,525,544		
2017	5	375,566	1,690,049	381,871	1,676,985		
2018	6	285,169	1,711,013	279,581	1,677,487		
2019	6	251,694	1,510,164	243,342	1,460,052		
2020	6	226,864	1,361,184	230,677	1,384,060		
2021	6	244,734	1,386,823	253,437	1,420,006		
2022	5	310,399	1,551,993	310,594	1,552,971		
2023	4	333,905	1,335,618	347,477	1,389,910		
2024	5			235,759	943,038	3,000,000	3,943,038
2025	5			229,509	918,036	3,600,000	4,518,036
2026	5			223,900	895,600	3,600,000	4,495,600
2027	5			218,825	875,300	3,600,000	4,475,300
2028	5			214,200	856,801	3,600,000	4,456,801

For clarify, the total normalized forecast excluding the new large customer is the forecast per customer multiplied by the four existing customers.

Figure 10. Actual vs Normalized R3



The R3 class has fluctuated between 4 and 6 customers since 2009. The current count of 4 customers is expected to increase to 1 in January 2024 with one known new customer.

6. NON-WEATHER SENSITIVE CLASS FORECASTS

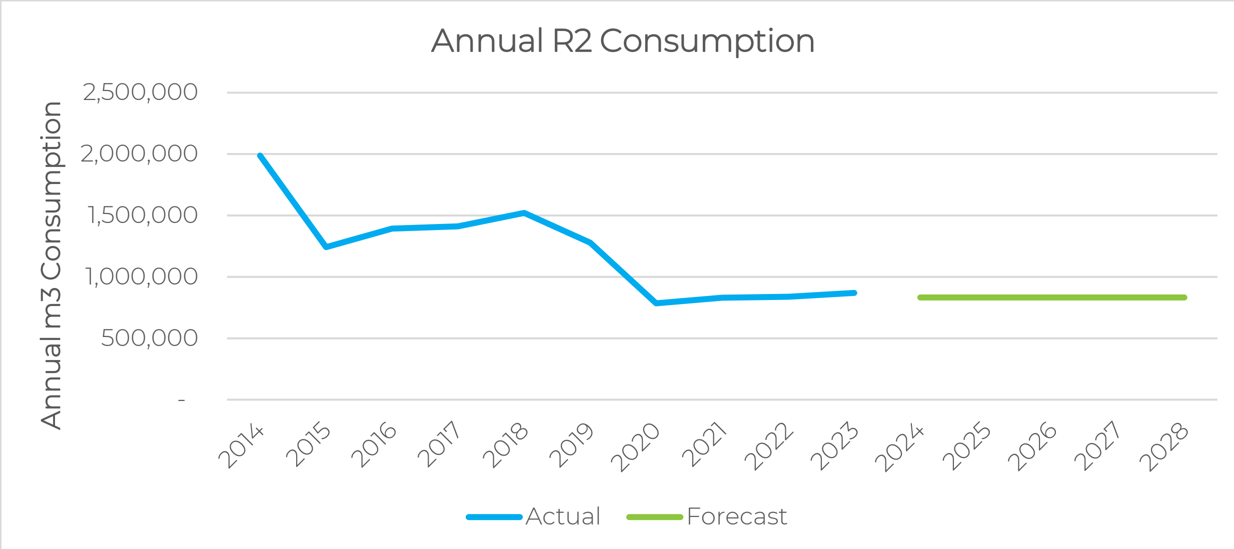
6.1 R2 Seasonal

Monthly consumption is forecast using a three-year average of consumption per customer in each month. The sum of monthly forecast values per customer are used to calculate annual total consumption as follows:

Table 24. Actual vs Normalized R2 Seasonal

R2 Seasonal						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2014	65	30,594	1,980,940	1,988,124		
2015	63	20,017	1,256,038	1,242,867		
2016	59	23,524	1,382,013	1,394,132		
2017	55	26,211	1,435,062	1,410,653		
2018	54	28,488	1,526,500	1,520,647		
2019	49	25,819	1,267,264	1,279,499		
2020	48	16,202	781,723	784,724		
2021	50	16,464	825,967	829,096		
2022	51	16,249	835,459	839,041		
2023	51	16,910	859,570	869,131		
2024	50				16,541	832,281
2025	50				16,541	832,281
2026	50				16,541	832,281
2027	50				16,541	832,281
2028	50				16,541	832,281

Figure 11. Actual vs Normalized R2 Seasonal



An average of tiered consumption shares in 2017 and 2018 was used to forecast tiered consumption in future years. The R2 seasonal class has three tiers with different rates in April to October and November to March. Tier 1 consumption is consumption up to 1,000 m^3, tier 2 applies to consumption between 1,000 m^3 and 25,000 m^3, and all consumption above 25,000 m^3 is considered Tier 3.

Table 25. Forecasted R2 Seasonal Tiered Consumption

	R2 Seasonal						
	April 1 to Oct 31			Nov 1 to Mar 31			
	Tier 1	Tier 2	Tier 3	Tier 1	Tier 2	Tier 3	Total
2022	55,865	466,630	89,145	43,354	172,637	11,411	839,041
2023	57,868	483,364	92,342	44,909	178,828	11,820	869,131
2024	55,415	462,870	88,427	43,005	171,246	11,319	832,281
2025	55,415	462,870	88,427	43,005	171,246	11,319	832,281
2026	55,415	462,870	88,427	43,005	171,246	11,319	832,281
2027	55,415	462,870	88,427	43,005	171,246	11,319	832,281
2028	55,415	462,870	88,427	43,005	171,246	11,319	832,281

The R2 customer count declined from 2014 to 2019 and has been stable around 50 customers since 2019. The number of R2 customers is forecast to remain at 50 from 2024 to 2028. The following table includes the customer Actual / Forecast customer count on this basis:

Table 26. Forecasted R2 Seasonal Customer Count

Year	R2 Seasonal Customers	Percent of Prior Year
2014	65	
2015	63	96.9%
2016	59	93.6%
2017	55	93.2%
2018	54	97.9%
2019	49	91.6%
2020	48	98.3%
2021	50	104.0%
2022	51	102.5%
2023	51	98.9%
2024	50	98.1%
2025	50	*100.0%*
2026	50	*100.0%*
2027	50	*100.0%*
2028	50	*100.0%*

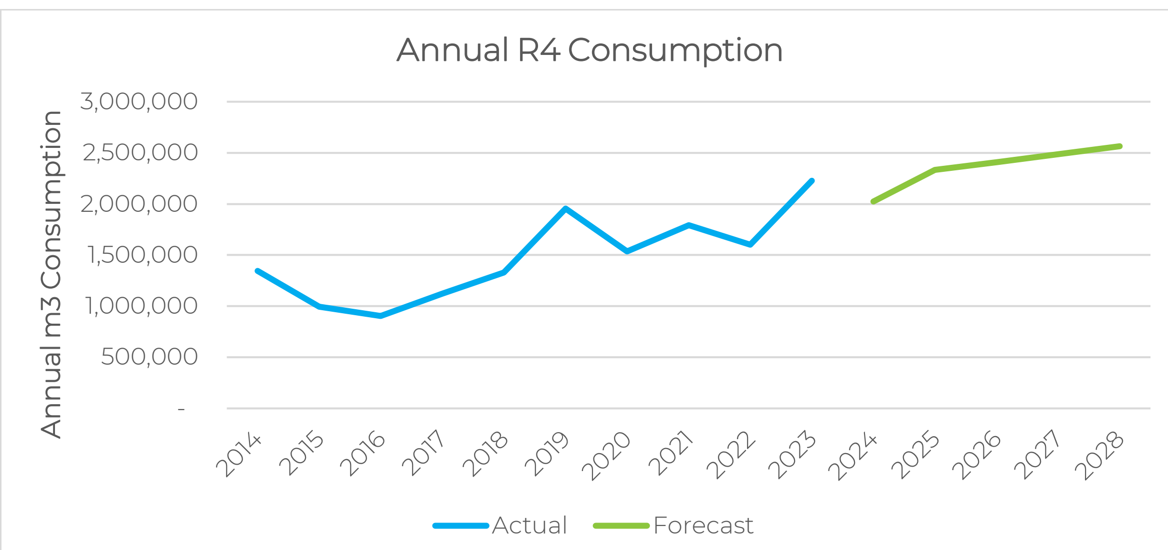
6.2 R4

Monthly consumption is forecast using a three-year average of consumption per customer in each month, with two adjustments. Consumption in November and December 2023 was anomalously high due to high crop yields. The crop yields, and associated grain drying load, is uncharacteristic of typical class consumption and ENGLP's expectations of the class's load in the future so November and December 2023 monthly volumes are excluded from average consumption forecast calculations. Forecast consumption in November and December of each year is calculated based on November and December 2021-2022 volumes. There is one known new customer in 2024 with forecast consumption that is materially higher than the average customer in the class. The increasing in consumption per customer resulting from this additional customer is included in the per customer forecast. The customer is forecast to attach in July 2024 so half of its incremental loads are added in 2024 and the remaining half is added in 2025.

Table 27. Actual vs Forecast R4

R4						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2012	25	23,036	575,898	678,458		
2014	33	39,661	1,318,721	1,345,169		
2015	34	29,232	996,339	994,710		
2016	35	25,140	888,266	904,160		
2017	36	31,238	1,119,348	1,124,029		
2018	37	35,029	1,278,561	1,327,953		
2019	37	50,232	1,841,844	1,953,378		
2020	40	37,145	1,501,271	1,534,283		
2021	41	43,427	1,766,026	1,793,580		
2022	42	37,551	1,564,633	1,601,474		
2023	43	50,688	2,200,708	2,227,329		
2024	45				44,732	2,023,938
2025	46				50,012	2,334,616
2026	48				50,012	2,408,833
2027	49				50,012	2,485,410
2028	51				50,012	2,564,421

Figure 12. Actual vs Normalized R4



An average of tiered consumption shares in 2017 and 2018 was used to forecast tiered consumption in future years. The R4 class has two tiers with different rates in January to March and April to December. Tier 1 consumption is consumption up to 1,000 m^3 and all consumption above 1,000 m^3 is considered Tier 2.

Table 28. Forecasted R4 Tiered Consumption

	R4				
	Jan 1 to Mar 31		Apr 1 to Dec 31		
	Tier 1	Tier 2	Tier 1	Tier 2	Total
2022	25,093	5,080	131,438	1,439,863	1,601,474
2023	34,899	7,065	182,804	2,002,561	2,227,329
2024	31,712	6,420	166,111	1,819,695	2,023,938
2025	36,580	7,406	191,609	2,099,021	2,334,616
2026	37,743	7,641	197,700	2,165,749	2,408,833
2027	38,943	7,884	203,985	2,234,598	2,485,410
2028	40,181	8,135	210,470	2,305,636	2,564,421

The Geometric mean of the annual growth from 2014 to 2023 was used to forecast the growth rate from 2024 to 2028.

The following table includes the customer Actual / Forecast customer count on this basis:

Table 29. Forecasted R4 Customer Count

Year	R4 Customers	Percent of Prior Year
2014	33	
2015	34	102.5%
2016	35	103.7%
2017	36	101.4%
2018	37	101.9%
2019	37	100.5%
2020	40	110.2%
2021	41	100.6%
2022	42	102.5%
2023	43	104.2%
2024	45	103.2%
2025	46	103.2%
2026	48	103.2%
2027	49	103.2%
2028	51	103.2%

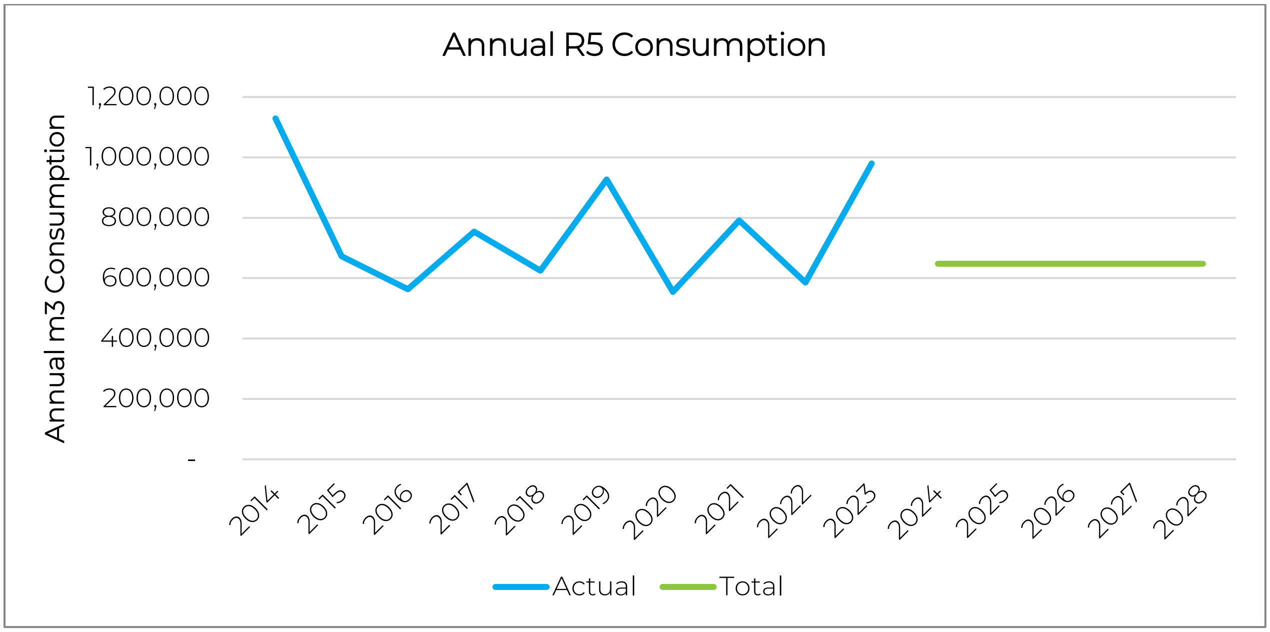
6.3 R5

Consumption per R5 customer has fluctuated considerably since 2014. The 2024 to 2028 forecast is based on a 3-year average from 2021 to 2023, excluding anomalously high consumption in November and December 2023. As described in the forecast for the R4 rate class, consumption in November and December 2023 was anomalously high because of high crop yields. The crop yields, and associated grain drying load, is uncharacteristic of typical class consumption and ENGLP's expectations of the class's load in the future so November and December 2023 monthly volumes are excluded from average consumption forecast calculations. Forecast consumption in November and December of each year is calculated based on November and December 2021-2022 volumes.

Table 30. Actual vs Forecast R5

R5						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2014	5	225,771	1,147,669	1,128,958		
2015	5	134,524	672,622	672,622		
2016	5	112,572	562,860	562,860		
2017	5	186,530	870,472	753,900		
2018	4	149,492	610,424	624,337		
2019	4	231,801	927,203	927,203		
2020	4	138,609	554,438	554,438		
2021	4	197,882	791,530	791,530		
2022	4	146,488	585,954	585,954		
2023	4	245,040	980,160	980,160		
2024	4				161,896	647,586
2025	4				161,896	647,586
2026	4				161,896	647,586
2027	4				161,896	647,586
2028	4				161,896	647,586

Figure 13. Actual vs Normalized Large Use R5



The R5 class had 5 customers from 2014 to 2017 and had 4 customers from 2018 to 2023. The current customer count of 4 customers is forecast to continue through 2024 to 2028.

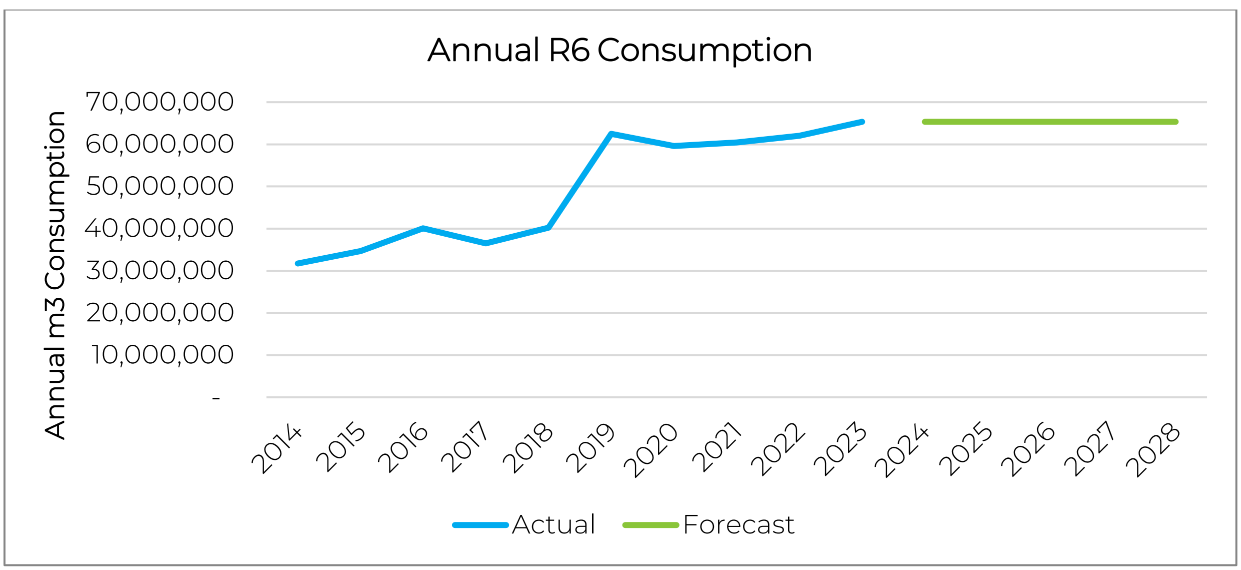
6.4 R6

R6 consumption increased significantly in 2019 over historic volumes. The 2024-2028 forecast uses 2023 consumption as forecast consumption in each year.

Table 31. Actual vs Forecast R6

R6						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2014	1	31,735,774	31,735,774	31,735,774		
2015	1	34,710,609	34,710,609	34,710,609		
2016	1	40,074,176	40,074,176	40,074,176		
2017	1	36,485,139	36,485,139	36,485,139		
2018	1	40,205,243	40,205,243	40,205,243		
2019	1	62,525,354	62,525,354	62,525,354		
2020	1	59,599,950	59,599,950	59,599,950		
2021	1	60,410,748	60,410,748	60,410,748		
2022	1	62,040,423	62,040,423	62,040,423		
2023	1	65,345,852	65,345,852	65,345,852		
2024	1				65,345,852	65,345,852
2025	1				65,345,852	65,345,852
2026	1				65,345,852	65,345,852
2027	1				65,345,852	65,345,852
2028	1				65,345,852	65,345,852

Figure 14. Actual vs Normalized R6



The R6 class has one customer and is expected to persist with one customer through 2028.

7. WEATHER SENSITIVITY

This section provides alternate low forecasts for scenarios with mild winters and high forecasts for cold winters. The low forecast uses the warmest winter in the past 10 years, which was 3,327 HDD (at 18°C) in 2023. The high forecast uses the coldest winter in the past 10 years, 4,306 HDD in 2014. The derived 18°C HDD forecast temperatures from 2024 to 2028 are provided with the normal forecast for reference. Forecast and actual HDDs from 2014 to 2023 are provided in Table 13.

Table 32. Low HDD Forecast

Low Forecast	HDD	3,327.2	3,327.2	3,327.2	3,327.2	3,327.2
	2023 Actual	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
R1 Residential	17,466,767	18,016,051	18,397,611	18,782,792	19,171,595	19,564,019
R1 Industrial	3,013,707	2,408,443	2,515,833	2,626,270	2,739,830	2,856,588
R1 Commercial	5,823,050	5,666,677	5,742,852	5,819,497	5,896,612	5,974,197
R2 Seasonal	869,131	832,281	832,281	832,281	832,281	832,281
R3	1,335,618	3,902,127	4,478,023	4,456,390	4,436,813	4,418,972
R4	2,227,329	2,023,938	2,334,616	2,408,833	2,485,410	2,564,421
R5	980,160	647,586	647,586	647,586	647,586	647,586
R6	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852
Total	97,061,614	98,842,955	100,294,653	100,919,501	101,555,979	102,203,916

Table 33. Normal HDD Forecast

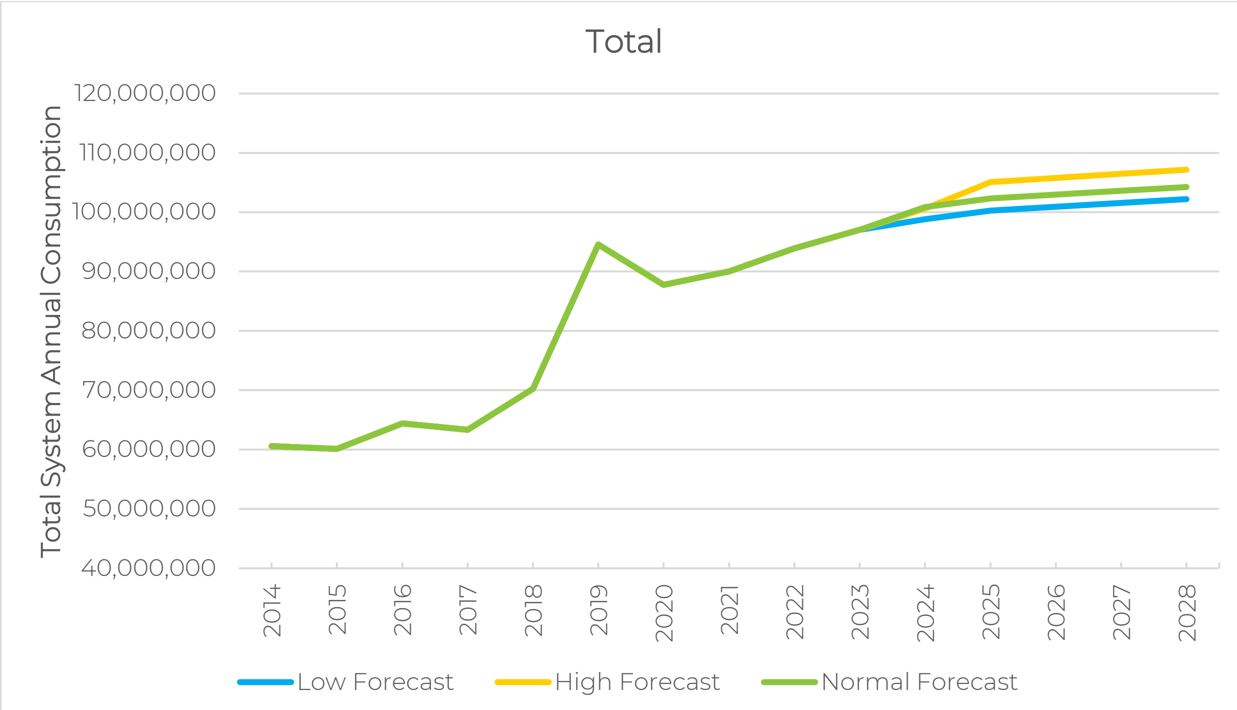
Normal Forecast	HDD	3,754.1	3,747.4	3,740.8	3,734.1	3,727.5
	2023 Actual	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
R1 Residential	17,466,767	19,394,143	19,778,416	20,165,775	20,556,215	20,949,733
R1 Industrial	3,013,707	2,579,897	2,686,373	2,795,837	2,908,361	3,024,023
R1 Commercial	5,823,050	6,119,454	6,193,869	6,268,637	6,343,760	6,419,235
R2 Seasonal	869,131	832,281	832,281	832,281	832,281	832,281
R3	1,335,618	3,943,038	4,518,036	4,495,600	4,475,300	4,456,801
R4	2,227,329	2,023,938	2,334,616	2,408,833	2,485,410	2,564,421
R5	980,160	647,586	647,586	647,586	647,586	647,586
R6	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852
Total	97,061,614	100,886,188	102,337,027	102,960,400	103,594,765	104,239,931

Table 34. High HDD Forecast

High Forecast	HDD	4,306.0	4,306.0	4,306.0	4,306.0	4,306.0
	2023 Actual	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
R1 Residential	17,466,767	21,143,218	21,567,872	21,996,147	22,428,043	22,863,562
R1 Industrial	3,013,707	2,879,826	2,995,562	3,114,494	3,236,698	3,362,254
R1 Commercial	5,823,050	6,700,310	6,785,323	6,870,806	6,956,759	7,043,182
R2 Seasonal	869,131	832,281	832,281	832,281	832,281	832,281
R3	1,335,618	998,650	4,571,969	4,548,022	4,526,352	4,506,603
R4	2,227,329	2,023,938	2,334,616	2,408,833	2,485,410	2,564,421
R5	980,160	647,586	647,586	647,586	647,586	647,586
R6	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852
Total	97,061,614	100,571,660	105,081,060	105,764,021	106,458,981	107,165,740

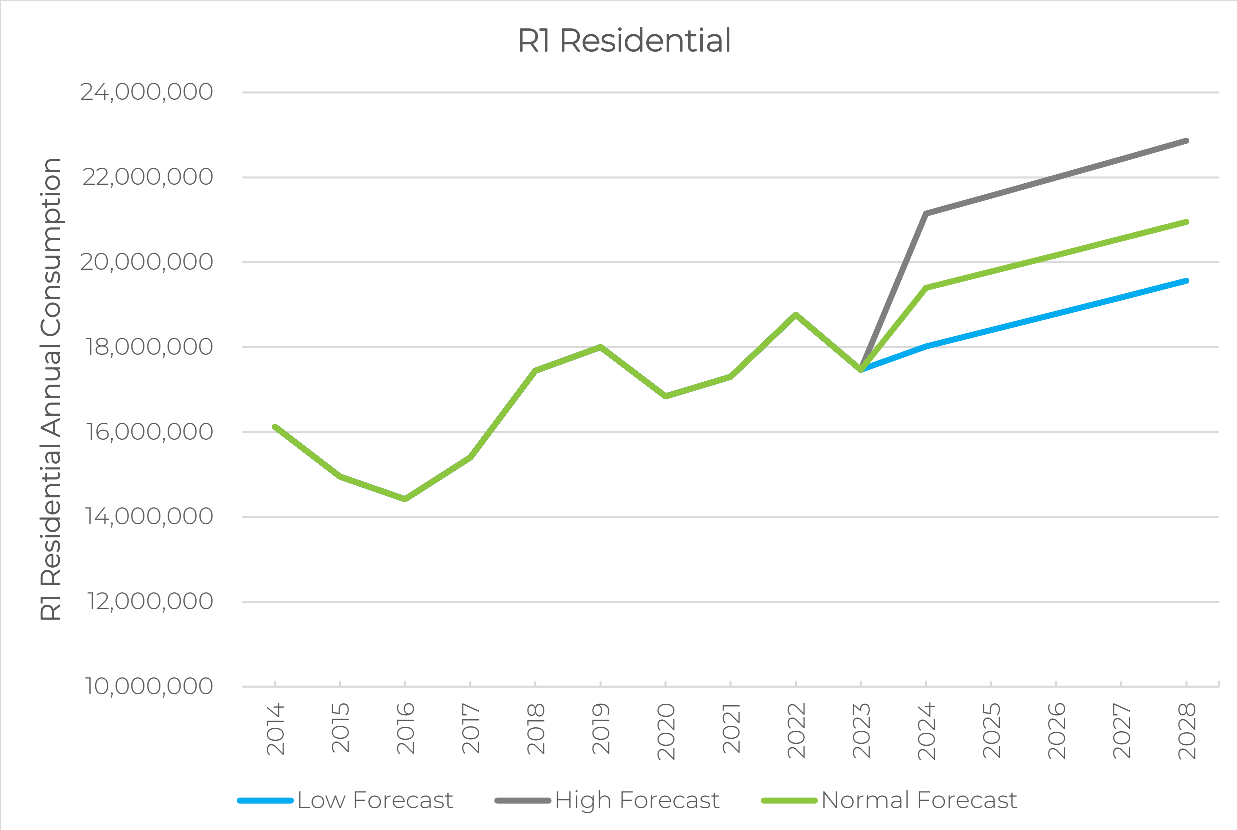
The graph below displays total forecast consumption for the three scenarios. The majority of consumption is not weather-sensitive so the range does not vary considerably on a total consumption basis.

Figure 15. Weather Sensitivity – Total Consumption



Consumption forecasts for only largest weather-sensitive class, R1 Residential, are displayed in the following graph. Note the y-intercept is non-zero in each graph.

Figure 16. Weather Sensitivity – R1 Residential



Appendix F – ENGLP Aylmer Performance Metrics Scorecard

OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	Sample	2021	2022	2023	3-yr Average
1. Cost Effectiveness	Policies & Procedures	Demonstrates consideration of alternate Enbridge rates	Annual rate review	C	C	C	C	n/a
	Price Effectiveness	Demonstrates local production a competitive option	Premium to system gas alternative	+/-%	**Well gas: -5%** **Lake gas: -5%**	**Well gas: -5%** **Lake gas: -5%**	**Well gas: -5%** **Lake gas: -5%**	**Well gas: -5%** **Lake gas: -5%**
OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	Sample	2021	2022	2023	3-yr Average
2. Reliability & Security of Supply	Design Day	Demonstrates ENGPL ability to procure transportation assets required to meet design day demand	1. Acquired assets to meet design day	%	100%	100%	100%	100%
			2. Enbridge Overrun Charges	$	$0	$0	$0	$0
	Coordination	Demonstrates ENGPL ability to invest in capital distribution required to meet design day demand	Monthly meetings between gas supply & engineering operations	12/yr	12	12	12	12
	Communication	Ensure ongoing communications	Communication to ratepayers re material bill impacts	C	C	C	C	N/A
	Diversity	Demonstrate the diversity of the portfolio	1. % Firm local gas flow	%	97%	98.82%	94.87%	97.01%
			2. Local production as % of system gas	%	37.01%	40.95%	37.51%	38.49%
			3. RNG as % of system gas	%	N/A	N/A	4.45%	4.45%
	Reliability	Demonstrate the reliability of the portfolio	1. Days failed to deliver to customers	#	0	0	0	0
			2.Days customer interrupted	#	0	0	0	0
OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	Sample	2021	2022	2023	3-yr Average
3. Public Policy	Supporting Policy	Reports public policy in ENGLP supply plan	1.Community expansion	C	C	C	C	N/A
			2. FCC	C	C	C	C	N/A
			3. RNG	N/A	N/A	N/A	N/A	N/A
			4. DSM	N/A	N/A	N/A	N/A	N/A

Definitions:
1. Years refers to calendar years (January 1st to December 31st)
2. Cost Effectiveness: The gas supply plans will be cost-effect. Cost effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner
3. Reliability and Security of Supply: The gas supply plans will ensure the reliable and secure supply of gas. Reliability and security of supply is achieved by ensuring gas supply to various receipt points to meet planned peak day and season gas delivery requirements
4. Public Policy: The gas supply plan will be developed to ensure that it supports and is aligned with public policy where appropriate