ENGLP AYLMER GAS SUPPLY PLAN: 2020-2024

MAY 2020

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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. ENGLP filed the Supply Plan for the period 2019-2024 as part of the utility's cost of service application, in proceeding EB-2018-0336. In that proceeding, the OEB approved the resulting cost consequences of the plan.

EPCOR Natural Gas Limited Partnership Aylmer ("ENGLP") has developed the following 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.

Guiding Principles for the Assessment of Gas Supply Plans

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, ENGLP developed a demand forecast that reflects its expected annual load profile over the five year rate period starting January of 2020. The demand forecast was used as an input in determining the appropriate mix between supply obtained from the Enbridge Gas 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 Gas.

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 ENGLP'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.

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

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, Renewable Natural Gas, and Community Expansion.

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

ENGLP is presenting this annual update, including upcoming decisions in the Supply Plan, with the aim of being transparent 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." Furthermore, ENGLP understands the Board's clarification in the Framework that "the assessment of the gas supply plans will not result in a decision on the costs or cost recovery. That would be the subject of related applications."[2] Accordingly, ENGLP understands that the Boards assessment of the Supply Plan will not be an assessment of prudency, or an assessment of the cost consequences of the Plan.

1.1. <u>Summary of Service Area</u>

The map below provides a summary of ENGLPs service territory which is current as of January 2020.[3] Key changes, relevant to the Supply Plan, include the addition of the 6 inch steel pipeline connecting off shore natural gas production to ENGLP's distribution system.

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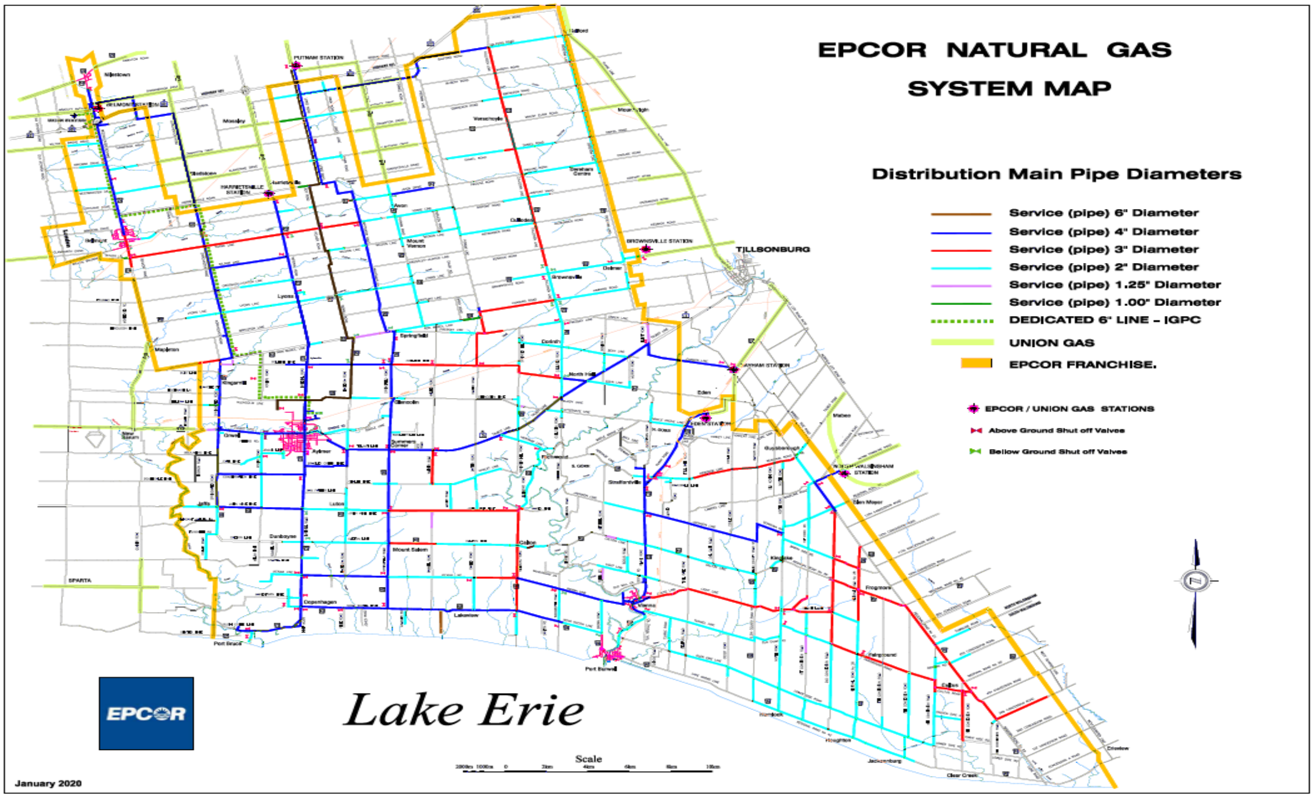
[2] EB-2017-0129, *Report of the Board*, dated October 25, 2018, at page 2.
[3] This map does not include the Village of Salford, a Certificate of Public Convenience and Necessity for this area was granted on January 16, 2020. The Village of Salford is proximate to the northeast corner of ENGLP's distribution system.


EPCOR NATURAL GAS
SYSTEM MAP
Distribution Main Pipe Diameters
Service (pipe) 6" Diameter
Service (pipe) 4" Diameter
Service (pipe) 3" Diameter
Service (pipe) 2" Diameter
Service (pipe) 1.25" Diameter
Service (pipe) 1.00" Diameter
DEDICATED 6" LINE – IGPC
UNION GAS
EPCOR FRANCHISE.
EPCOR / UNION GAS STATIONS
Above Ground Shut off Valves
Bellow Ground Shut off Valves
TILLSONBURG
Lake Erie
EPCOR
Scale
January 2020

1.2. Significant Changes

The introduction of incremental firm gas supply in the Southern area of the distribution system is the most significant change to the previously filed gas supply plan. This section of the Supply Plan will detail how ENGLP determined the parameters for the **new** long-term gas supply contract with Lagasco Inc. This plan will outline (a) Cornerstone Energy Services' ("Cornerstone") assessment of the landed costs of this new natural gas supply compared to alternatives, and (b) ENGLP's risk assessment including forecasting risk, operational risk, commercial and regulatory risk associated with any long-term supply arrangement, and how the utility proposes to address these risks in order to minimize the impact to its ratepayers.[4]

Background

In 2018, ENGLP committed to and engaged Cornerstone to produce a System Integrity Study ("Cornerstone Study"). This Study informed ENGLP on the volume and location of gas that is required to be purchased in order to ensure system integrity. The Study is included in the ENGLP Cost of Service filing, in proceeding EB-2018-0336.

The results of the Cornerstone Study indicated that local production for up to 1030 m3/hr is necessary and the most cost effective manner in which to address the observed system integrity and low pressure issues in the south and southeast area of the system. Cornerstone concludes that "indigenous gas supply from the existing Lakeview station on Gully Road, although less flexible than CNG, offers the most advantageous solution."[5]

It is important to note that there are two distinct agreements in place for local production.

The first agreement pertains to the former NRG wells, located on-shore, in the ENGLP distribution system ("NRG Contract"). These wells were sold by NRG's previous owner and through a series of transactions, including an insolvency filing, and are currently held by Lagasco Inc. ("Lagasco").

ENGLP continues to purchase the on-shore production under terms approved by the OEB. Specifically, those approvals enabled ENGLP to continue to purchase gas under the same terms until the supply contract expires in September of 2020. The OEB in its findings in EB-2010-0018 stated:

> ***"The Board will allow NRG to recover from ratepayers a maximum annual quantity of 1.0 million cubic meters of natural gas at the rate of $8.486 per mcf. Any additional quantities beyond 1.0 million cubic meters that are purchased from NRG Corp. would only be eligible for recovery from ratepayers at current market rates that would be determined quarterly as per the methodology outlined in the Board's Decision of December 6, 2010."***

[4] EB-2019-0288, Decision and Order, dated December 23, 2019, at page 3.
[5] EB-2018-0336, Application and Pre-filed Evidence, Exhibit 2, Tab 3, Schedule 2, pages 18-20.

The second gas supply agreement is in response to the pressure problems identified by Cornerstone in the south and southeast area of the distribution system ("Lagasco Contract"). Between 2011 and 2017 NRG had discussions about additional gas supplies, though no supplier was willing to offer gas at a competitive price.[6] Later, in 2018, Lagasco approached ENGLP with a proposed solution which involved tying in off-shore gas production[7] and offering competitive pricing. ENGLP entered into a new long term contract with Lagasco effective October 3, 2019; however, services and obligations under the agreement commenced on December 1, 2019 and gas volumes began to flow in the latter half of December 2019.

ENGLP also developed a capital and implementation plan in order to tie-in incremental Lagasco production sourced from Lake Erie. The capital plan was approved as part of ENGLP's Cost of Service application (EB-2018-0336).

Description of Project Purpose

ENGLP's natural gas distribution system is currently fed at distribution pressure (80 psig) from the Enbridge Gas' Union South system at seven regulating and metering stations on the northern and eastern edges of the service area. Production from the connected well supply in the south has declined over time and now provides a small fraction of the overall gas supply requirement.

Given the way the system has developed, customer growth (approximately 3%) and the declining well supply (16% per year)in the south, unacceptably low system pressures in the south of the system during periods of peak demand have become a concern. To continue to ensure safe and reliable service to existing customers in the area, support ongoing customer growth and expand access to natural gas, reinforcement of the system is required.

System modelling completed in 2018 as part of the Cornerstone Study showed materially lower operating pressures in the south and southeast part of the system during periods of peak demand. This confirms recent observations by operating staff.

In January 2019, during a period of near record low temperatures and resulting record high natural gas demands, pressures well below the 30 psig minimum design pressure were observed in the south. Pressures in Port Burwell, a small community on the lakeshore, were below 5 psig and the utility was at risk of unplanned customer outages. These concerns will be amplified as demand increases and production from the connected wells continues to decline.

[6] EB-2019-0276, Response to Board Staff Interrogatory 11, filed January 24, 2020.
[7] EB-2018-0336 (Phase 2), Application and Evidence, filed August 1, 2019, at page 12-13, paragraph 5.

Proposed Solution

The purpose of the Cornerstone Study was to undertake a review and identify solutions to the constraints within the Aylmer utility natural gas distribution system that existed in 2018. Cornerstone was asked to:

- Review the distribution system and, given current peak system demands, identify system constraints that are likely to lead to unacceptable low pressure conditions;
- Given forecasted growth, identify system constraints that are likely to lead to unacceptable low pressure conditions through 2024; and
- Identify and evaluate options to address the system constraints and resolve the unacceptable low pressure conditions identified.

The study identified low pressure issues in the southern and southeastern part of the system, confirming recent operating history. The study identified and confirmed options to address these low pressure issues, which included tying to a new natural gas supply from a third-party producer near Lakeview. Additional volumes to the area would boost pressure to ensure reliable supply during peak demand and enable the utility to serve customers it had declined to service in the past.

ENGLP proceeded to address these system issues prior to the 2019 heating season. ENGLP amended its capital plan and negotiated a gas supply agreement with Lagasco. Under the agreement, Lagasco would provide 1200 GJ/d of locally produced gas on a **firm basis** at its Lakeview Compressor Station, located on the lakeshore between Port Bruce and Port Burwell. The initial term of the agreement is 5 years. The pricing provisions balance the need for transparency and adequately compensates Lagasco for the necessary infrastructure investment needed to ensure reliable pipeline quality gas.

Subsequent modelling completed by Cornerstone has confirmed this additional supply has resolved the targeted low pressure issues.

To connect to the new supply, a new regulating and metering station was required at the Lakeview site (downstream of the Lagasco dehydrator equipment) to regulate gas pressure down from the supplied pressure of 350 psig to the 80 psig maximum allowable operating pressure of the ENGLP distribution system. A bypass-type odorizer has been located at the station to add odorant to the gas supplied. The station is located on a sub-lease on the Lagasco compressor station site. This project was not included in the utility's 2019 budget but was included in the Bridge Year of the most recent ENGLP cost-of-service rate filing (EB-2018-0336) at an estimated investment of $357,000.

The current project cost estimate for of $461,000 is $104,000 higher than the estimated cost included in the cost-of-service rate filing. This difference is primarily a result of increasing the pipeline size from 4 inches to 6 inches. As future demands increase and production from the connected wells continues to decline, it is important to ensure safe and reliable service to existing customers and support ongoing development in the area. As a result, although a 4 inch pipeline would be adequate for the firm contracted gas volume of 1200 GJ/d, the 6 inch pipeline infrastructure was sized at the location to accommodate the availability of nearly twice the contracted firm volume during peak demand periods now and in the future.

The new regulating and metering station will be connected to the existing 4 inch Nova Scotia Line pipeline with a new 6 inch PE pipeline, approximately 1300 m long, running parallel to Gully Road. The pipeline will be located in an existing Lagasco right-of-way.

Alternatives Considered

In determining the appropriate solution, ENGLP considered a number of alternatives and evaluated for their: reliability, flexibility, diversity and costs. These alternatives are discussed in detail and a summary matrix is provided below.

Incremental Supply Options: Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Cost ($M)
Lake Side Tie In	↑	↑	↑	↑
CNG	→	↑	↑	↓
Upstream Reinforcement	↓	→	→	→
Existing Wells	↓	↓	↓	↓
3rd Party Production	→	→	↓	↓
Status Quo	↓	↓	↓	→

CNG

ENGLP considered adding trailered compressed natural gas (CNG) on-system storage in the south of the system, to be used to supplement the existing gas supply during peak demands. The capital cost of this option, based on a preliminary engineering estimate, is in excess of $2,500,000, significantly higher than tying in incremental production (then estimated at $375,000). This approach would also have higher ongoing operating and maintenance costs. The reliability of supply would also have to be properly addressed, as peak demands occur in the winter when road conditions can be poor, potentially making it difficult to move CNG trailers when required. As such, this alternative was rejected.

Upstream Reinforcement

A steel pipeline to move gas at a higher pressure from a transfer point from Enbridge Gas' Union South system was also considered at a conceptual level. Capital costs for this option would be expected to be well above $10,000,000 before considering any Enbridge Gas upstream reinforcement costs. Given the high capital cost for this alternative, it was also rejected.

Incremental Production from Existing Wells

ENGLP's consultant GSA Energy indicated that there was significant economic depletion in the remaining production life of NRG Corp wells (now 2661031 Ontario Inc., a subsidiary of Lagasco). In addition, none of these points of supply are located to the south or west of the franchise area where significant new gas supply was required in order to ensure that customers in the Southeast continued to receive reliable service.

Tying incremental lake gas is the only local production capable of delivering to ENGLP gas in the south and southeast of the system where it is needed. Therefore, due to the rapid depletion of existing wells and their location, this option was rejected.

Third Party Production

Since the consolidation of local production within ENGLP's franchise area, options from third party producers are limited. However, ENGLP did engage in discussions with another third party producer and proposed the identical pricing structure as the Lagasco Contract. The feedback received was that the pricing proposed (e.g. discount to the M9 rate) was insufficient to make it economically viable for the producer to invest in the required infrastructure to bring retired or new wells on stream. Therefore, incremental production from other producers was not an option.

Status Quo

ENGLP also considered the consequences of not undertaking the project (i.e. the Lagasco Contract). In January 2019, during a period of near record low temperatures and resulting record high natural gas demands, system pressures in the south were well below system design and the utility was at risk of unplanned customer outages. The situation will only get worse as demands increase and production from the connected wells continues to decline. In order to continue to ensure safe and reliable service to existing customers and support ongoing development in the area, ENGLP determined that reinforcement of the system was required.

Risk Assessment

In making its determination, ENGLP considered the following risk factors: contracting risk, forecasting risk, operating risk, cost consequences and impact on the average residential customer. Each of these risks are discussed in detail below.

Contracting Risk

Historically, ENGLP had solely relied on Enbridge Gas for firm gas requirements. Incremental gas was purchased from local wells; however, due to the declining nature of the local wells the gas was not firm or, in other words, it does not have the same reliability as gas contracted on a firm basis. The gas requirements for the southern part of the franchise were identified as requiring a firm gas solution and, in contracting for firm gas, a contract demand must be established.

Contract Demand attracts a Contract Demand pricing component in order to ensure firm gas deliveries. Based on input from Cornerstone and to accommodate future growth, ENGLP determined that the appropriate level of firm gas required in the southern area was 1,030 gj/day (or 30,785 M3).

At that same time, ENGLP contract demand for system supply has consistently increased due to higher peak day requirements associated with system growth. Enbridge Gas establishes its Contract Demand based on the number of peak days in the previous contract year and adjusts the Contract Demand to ensure there is sufficient capacity to reliably meet those demands.

The example below shows that in the 2017-2018 period, ENGLP's system Contract Demand was 177,234 m3. Enbridge Gas provides for an allowed overage of 3% or, in this instance, the equivalent of 182,551 m3. However, the system experienced high usage in January of 2017 consuming an incremental 25,879 m3 for a total of 208,430 m3. Accordingly, in 2018, the Contract Demand was adjusted upwards to 208,430 m3.

Enbridge Distribution Contracts		Nov 2018-Nov 2019	Nov 2017-Nov 2018
SA1550	System Gas	208,429	177,234
	Contract Demand *103%	214,682	182,551
	OverRun	26,998	25,879
	Peak Requirement on Enbridge system	***241,680***	***208,430***
		116%	112%

In 2019, ENGLP's peak consumption reached 241,680 m3 on January 6th, 2019. Under normal contracting practices, ENGLP's Contract Demand with Enbridge Gas should have increased to 241,680 m3. However, Enbridge Gas indicated that due to a system implementation, ENGLP Contract Demand would not be adjusted upward for the 2019/2020 contract year.

Based on this Enbridge Gas' decision not to adjust Contract Demand upwards combined with the lack of operational experience with the new supplies ENGLP concluded that the current Contract Demand obligation with Enbridge Gas was appropriate in order to ensure system reliability whilst balancing costs.

Early indications demonstrate the Lagasco contract is performing as expected and effectively lower the Contract Demand requirements with Enbridge Gas for the upcoming contract year. With the addition of the Lagasco firm gas volumes the peak day requirement on the Enbridge Gas contract has been reduced to 219,373m3 from 241,680m3. In addition ENGLP's peak day overrun of 4, 691 occurred in November (prior to Lagasco flowing gas) rather than in January further increasing the overall reliability of the Distribution system.

Enbridge Distribution Contracts		Nov 2019-Nov 2020
SA1550	System Gas	208,429
	Contract Demand *103%	214,682
	OverRun	4,691
	Peak Requirement on Enbridge system	***219,373***

ENGLP will continue to monitor its peak day requirements, bearing in mind 2019 was a warmer than normal winter, and work with Enbridge Gas to adjust on an annual basis when required.

Forecasting Risk

As the Lake Erie tie-in is incremental new supply, ENGLP has no historical operating data to rely upon. In order to mitigate this risk, ENGLP maintained (rather than decreasing) its annual obligation to Enbridge Gas with respect to firm gas deliveries via the Enbridge Gas system for the 2019/2020 contract year. ENGLP evaluates its Contract Demand requirements on an annual basis.

ENGLP also initiated a SCADA (Supervisory Control and Data Acquisition) project as part of ENGLP's approved capital plans. A SCADA system will provide for real time remote monitoring of distribution system pressure.

Operating Risk

ENGLP's chief operating risk associated with the Lake Erie gas supply is that of gas quality. ENGLP was specifically concerned about the water content of the gas and the possible effects of freezing/hydrate formation in the distribution system.

In order to mitigate this risk, the Lagasco Contract provides for a gas quality clause. This clause requires that the natural gas be delivered at pipeline quality specifications, specifically the water dew-point, to ensure no freezing/hydrate formation in ENGLP's system.

In order to comply with this clause, Lagasco has invested in a take-off from their Lakeview Compressor Station to supply natural gas to the ENGLP distribution system. Natural gas entering the Lakeview Compressor Station will be compressed to about 350 psig, dehydrated through a conventional TEG dehydrator then piped to the ENGLP take-off where the pressure will be reduced to ENGLP's MAOP, metered, odorized, and delivered into the system. A schematic of this system can be found in Appendix 10.3.

Cost Consequences

The Lagasco Contract is comprised of a Monthly Demand Charge, a Delivery Commodity Charge and a Commodity Charge. The Monthly Demand Charge reflects typical industry practice of contracting for firm gas supply. In keeping with the principles of transparency, all prices are at or below the current OEB approved M9 rate. For greater clarity, a typical winter invoice is provided below.

Enbridge vs Lagasco Monthly Sample Cost Comparison-February Volumes
(assuming Contract Demand of 1,200 GJ's/day or 30,785 m3)

Enbridge-OEB Approved M9 Rate			
Description	Unit Cost	Units	Invoice Amount
Monthly Demand Charge	$0.24360	30,785	$7,499.17
Delivery Commodity Charge	$0.00136	755,327.7	$1,023.47
Gas Supply Commodity	$0.11731	755,327.7	$88,609.00
Total			$97,131.64

Lagasco			
Description	Unit Cost	Units	Invoice Amount
Monthly Demand Charge	$0.24360	30,785	$7,499.17
Delivery Commodity Charge	$0.00136	755,327.7	$1,023.47
Gas Supply Commodity *	$0.11145	755,327.7	$84,178.55
Total			$92,701.19

* Commodity in the Lagasco contract is priced at a 5% discount to Enbridge's OEB QRAM

The Lagasco Contract is priced below the Enbridge Gas system supply but the delta will fluctuate depending on the quantity of gas purchased in any given month. This pricing mechanism provides incentive for ENGLP to source local production on a preferential basis to Enbridge Gas' gas supply. Our operational team adjusts pressures and flows accordingly.

Residential Bill Impacts

ENGLP engaged Aiken & Associates to perform a residential bill analysis, which is summarized in the table below.

ANNUAL BILL IMPACT-NO LOCAL PRODUCTION C	
01-Jan-20	
With No Local Production (C)	
Average Residential Consumption	1,780.0
Monthly Charges	$210.00
Delivery Charges	$238.19
Total Commodity Charges	$248.54
Total Customer Charges	$696.73
RATES USED (1)	
01-Jan-20	
With No Local Production (C)	
Monthly Charge	17.50
Delivery Charge	0.133814
Total Commodity Charge	0.139629
(1) Rates shown do not include any rate riders.	

ANNUAL BILL IMPACT- With LOCAL PRODUCTION (C)	
01-Jan-20	
With Local Production (C)	
Average Residential Consumption	1,780.0
Monthly Charges	$210.00
Delivery Charges	$238.19
Total Commodity Charges	$245.88
Total Customer Charges	$694.07
RATES USED (1)	
	01-Jan-20
	0
Monthly Charge	17.50
Delivery Charge	0.133814
Total Commodity Charge	0.138135
(1) Rates shown do not include any rate riders.	

The introduction of the Erie Lake Gas Supply production results in a modest $2.66 reduction to the average annual residential bill**.**

2. Demand Forecast

To develop a natural gas supply portfolio, ENGLP 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 Elenchus on April 17, 2020 for purposes of this gas supply plan. Please refer to the end of this section of the forecast methodology.

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),
- **Seasonal Customers:** Rate 2, and
- **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).

General Service Customers

General Service customers (residential, commercial, and industrial) are forecasted to make up approximately 29.2% of ENGLP's demand profile in 2020.

Residential customers make up the majority (64.4%) of the General Service demand profile. While the residential segment is expected to have the highest growth in terms of customer numbers (from 8,663 to 8,929), demand is expected to remain relatively flat in 2020 compared to 2019 weather-normalized demand. Commercial customers make up approximately 21.1% of the General Service demand profile. In 2020, 552 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 14.5% of the General Service demand profile. There are 75 non-interruptible and 37 interruptible industrial customers in the ENGLP natural gas system forecasted for 2020.

Contract Customers

Contract customers are forecasted to make up approximately 69.5% of ENGLP's demand profile in 2020. There are currently 11 customers under this classification and no change in customer numbers are forecasted in 2020. 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 2.5% of ENGLP's demand profile by volume.

Seasonal Customers

Seasonal customer are forecasted to make up the remaining 1.3 % of ENGLP's demand profile in 2020. There are 44 customers under this rate class and that consist mainly of tobacco framing and curing customers (non-interruptible).

The following Tables provide ENGLP's Customer Connection Forecast and Annual Customer Service Demand Forecast by Rate Class. The forecasted 2020 values are provided by Elenchus Research Associates Inc. ("Elenchus") in their Weather Normalization and Distributions System Load Forecast (EB-2018-0336, Exhibit 3, Tab 2, Schedule 1) and updated for purposes of this gas supply plan. The updated Elenchus report can be found in Appendix 10.2.

Table 3-1
Forecast of Customer Connections

	2019 Actual	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast
R1 Residential	8663	8929	9204	9488	9780	10081
R1 Industrial	73	77	82	86	90	95
R1 Commercial	537	552	568	584	600	617
R2 Seasonal	49	47	46	44	42	41
R3	6	6	6	6	6	6
R4	37	40	41	42	43	45
R5	4	4	4	4	4	4
R6	1	1	1	1	1	1
Total	**9,370**	**9,656**	**9,952**	**10,255**	**10,566**	**10,890**

Table 3-2
Forecast Annual Customer Service Demand, by Rate Class

	2019 Actual	2019 Normal	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast
R1 Residential	18,006,476	17,605,176	17,521,080	18,114,687	18,728,136	19,362,081	20,017,199
R1 Industrial	2,461,420	2,369,312	2,230,507	2,388,524	2,556,992	2,736,573	2,927,968
R1 Commercial	5,890,510	5,766,774	5,739,519	5,952,003	6,171,885	6,399,414	6,634,844
R2 Seasonal	1,279,499	*1,279,499*	1,166,433	1,124,687	1,084,435	1,045,624	1,008,202
R3	1,510,164	1,465,408	1,579,434	1,507,691	1,444,418	1,388,075	1,337,485
R4	1,953,378	*1,953,378*	1,734,530	1,946,379	2,184,104	2,450,862	2,750,202
R5	927,203	*927,203*	757,096	757,096	757,096	757,096	757,096
R6	62,525,354	*62,525,354*	62,525,354	62,525,354	62,525,354	62,525,354	62,525,354
Total	**94,554,003**	**93,892,105**	**93,253,953**	**94,316,421**	**95,452,420**	**96,665,079**	**97,958,351**

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 removed from the regression.

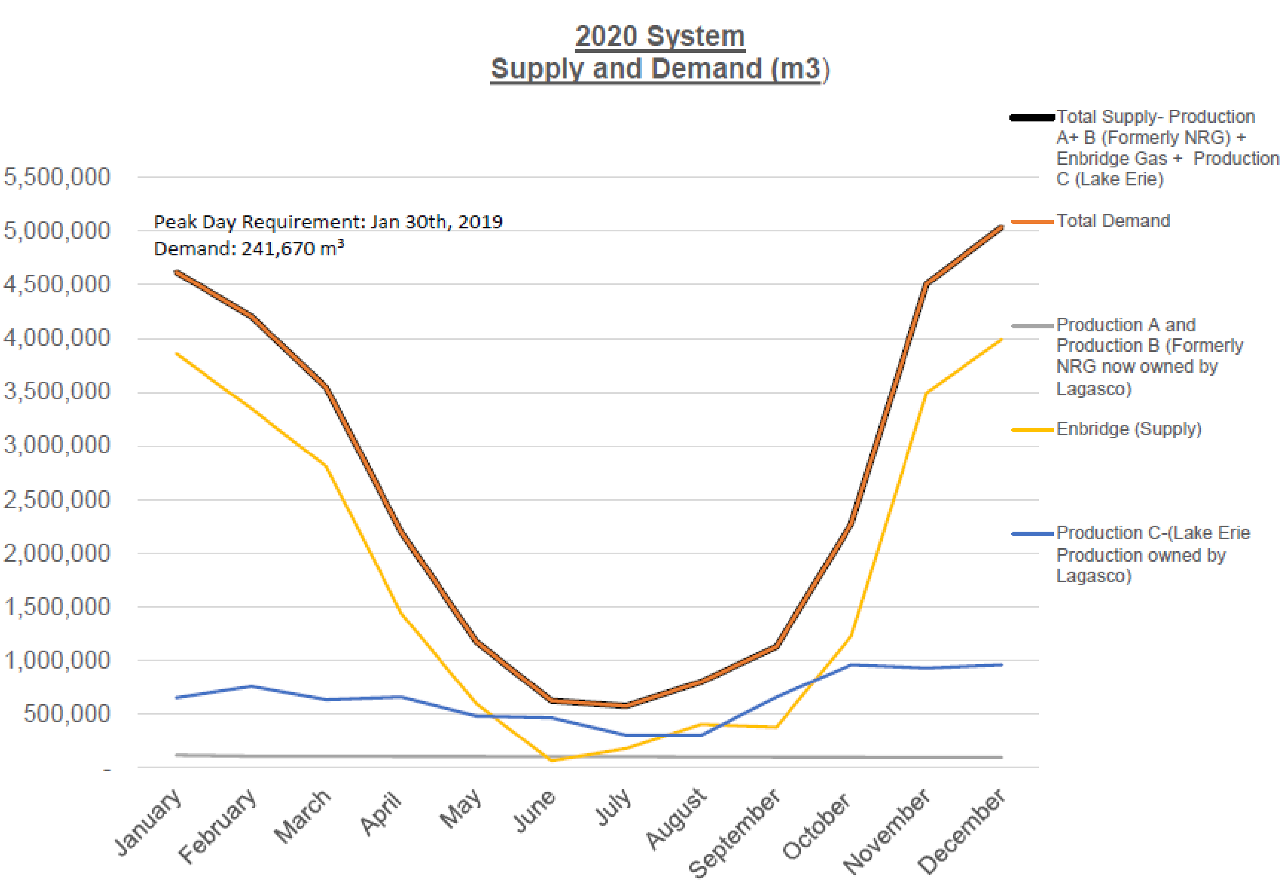
Consumption of the remaining four rate classes (R2 Seasonal, R4, R5 and R6) were not weather-sensitive and did not exhibit sensitivity to the explanatory variables. Total and monthly volumes fluctuate from year-to-year and as such, a 5-year rolling average was used to forecast monthly consumption for 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 2009 to 2019 to the 2019 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 2020 calendar year, including incremental local production.



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

ENGLP 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 ENGLP 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 9747 m^3/h, thus all loads had to equal that number.

This work provided ENGLP 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.

Actual & Forecast Demand Requirements

			Lakeside CD =1200 GJ/day		
			30,856 HV= 38.89		
Year	Actual and *Forecast* Peak Demand (Cornerstone)*	Actual and *Forecast* CD (Enbridge)	Lakeview CD		
2016	186,589	177,234		177,234	
2017	197,278	177,234		177,234	
2018	208,650	208,429		208,429	
2019	241,670	208,429	*30,856*	239,285	
2020	*246,504*	*215,648*	*30,856*	*246,504*	
2021	*251,434*	*220,578*	*30,856*	*251,434*	
2022	*256,463*	*225,607*	*30,856*	*256,463*	
2023	*261,592*	*230,736*	*30,856*	*261,592*	
2024	*266,824*	*235,968*	*30,856*	*266,824*	
Note: * Assume 2% growth YOY as per Cornerstone					

3.1.2 Weather

ENGLP retained Elenchus to provide a Weather Normalized Distribution System Load Forecast. A copy of this report is provided in Appendix D.

3.1.3 Commodity

ENGLP receives the majority of its commodity under the bundled M9 rate which is based on Enbridge Gas' OEB approved WACOG application. ENGLP currently has three M9 Large Wholesale Service Contracts; SA1550 (System Gas) with a contract demand of 208,429 m^3, SA25050 (Direct Purchase) with a contract demand of 13,366 m^3 and SA8936 (IGPC) with a contract demand of 208,800 m^3.

The balance of ENGLPs commodity requirements are sourced from local production.

3.1.4 Transportation

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

ENGLP currently contracts for an annual Contract Demand in the amount of 208,429 m^3 for its System Gas customers. ENGLP evaluates its Contract Demand requirements with Enbridge Gas on an annual basis and will balance the need to maximize its usage and minimize over run charges under this contract.

3.1.5 Storage

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

3.1.6 Daily Balancing Management

ENGLP is not required to Daily Balance its gas supply as that service is provided by Enbridge Gas under the M9 service agreement.

3.1.7 Direct Purchase Program

ENGLP has Direct Purchase Customers in its system whereby these customers arrange for gas supply and/or upstream transmission services directly with Enbridge Gas or ENGLP's distribution service to deliver gas to end-user locations. Currently, approximately 1.% of ENGLP customers are on direct purchase compared to system sales and represent approximately 62% of ENGLP's demand profile by volume.

ENGLP relies on the Direct Marketer to deliver the volumes to Enbridge Gas. In accordance with the Bundled T-Service Receipt Contract between ENGLP 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 ENGLP harmless with respect to the excess of any costs and expenses incurred by ENGLP in acquiring such Gas and transportation capacity.

3.1.8 Long-Term Contracts

As previously noted, ENGLP signed a long-term (5 year) gas supply agreement with Lagasco on October 3, 2019, and the services commenced on December 1, 2019. This supply agreement will ensure there is sufficient gas supply in the Southeast area of the distribution system where ENGLP has historically suffered from low pressure issues that undermine security of supply. The pricing terms of this contract are benchmarked to pricing available to ENGLP, specifically the M9 rate. This will ensure ENGLP's customer rates are not negatively impacted.

This long-term ***firm*** supply contract will ensure any capital improvement projects identified in the capital plan that are undertaken to address system pressure issues are optimized.

3.1.9 Diversity of Supply

Diversity of supply is identified as a key consideration to the Gas Supply Plan. The introduction of incremental local production diversifies the portfolio as demonstrated in the analysis below:

Supply Source Breakdown-Forecast

	Enbridge	Production A & B	Production C	Total
2024	73.4%	1.8%	24.8%	100%
2023	72.3%	2.2%	25.5%	100%
2022	71.1%	2.6%	26.2%	100%
2021	69.9%	3.2%	26.9%	100%
2020	70.9%	3.9%	25.2%	100%

Supply Source Breakdown-Historical

	Enbridge	Production A & B	Production C	Total
2019	94.9%	4.6%	0.5%	100%
2018	96.5%	3.5%	0.0%	100%
2017	94.3%	5.7%	0.0%	100%
2016	94.5%	5.5%	0.0%	100%
2015	92.4%	7.6%	0.0%	100%

3.1.10 Alternative Rate Consideration

In evaluating alternative rate options offered by Enbridge Gas, ENGLP evaluated the economics of the M9 or Large Wholesale Service rate versus alternative rate offered, considering the predecessor to ENGLP's previous experience following the winter of 2014 and the subsequent financial penalties. In addition, ENGLP examined the resources necessary to manage rate alternatives.

The M9, or Large Wholesale Service, Rate service offers supply and transportation services including, Commodity Supply (Rate approved by the OEB), Seasonal Storage Services, Daily Balancing and a nomination service. ENGLP completed a two year analysis of the premium associated estimated with the M9 service examining the M9 price versus buying gas directly at Dawn. ENGLP concluded that the utility incurs a 9% premium or approximately $375,000 annually for this service.

In order to replicate this service, ENGLP would require investment in a number of resources including, but not limited to:

1. A minimum of two employees to manage gas supply including nominations, upstream transportation contract capacity, seasonal storage contracting, daily balancing contracting and market surveillance;
2. Load forecasting IT systems;

3. Smart meters and, potential, SCADA enhancements; and
4. Credit support for long-term upstream transportation contracting.

Additionally, in order to meet ENGLP's heat load or human needs peak day requirements, load management tools embedded in the distribution system itself are required. These critical tools, currently not embedded in ENGLP's system, include incumbent storage and end-use industrial interruptible customers.

4. Gas Supply Plan Recommendations

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

ENGLP is also developing the Southern Bruce natural gas franchise and as ENGLP 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. ENGLP 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 ENGLP.

ENGLP will complete this re-evaluation prior to the filing of the next major gas supply plan.

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), ENGLP will evaluate its current demand, its forecasted growth and direct purchase demand. This will help establish the annual Contract Demand with Enbridge Gas under each of the M9 contracts (System Gas Customers, Direct Purchase Customers and IGPC). ENGLP 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 Gas.

ENGLP 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 ENGLP has to operate within the limits set by Union. ENGLP will also establish an annual review (including 2019) 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 ENGLP will continue 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.

ENGLP did complete a review of the Residential accounts at the end of December 2019 and re-classified those customers that should have classified as commercial or industrial

5.2 Evaluation of Procurement Process and Policies

ENGLP purchases the majority of its commodity from Enbridge Gas. ENGLP 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.

ENGLP procures a number of other gas related services including consulting services such as those provided by ECNG Energy LP. These other services are initiated through a Request for Proposals (RFP) process provided through a Shared Services Agreement with EPCOR Water Services Inc. (EWSI), an Edmonton-based corporation. The RFP process is governed by a Procurement Document which provides guiding principles; non-competitive procurement procedures; approvals and limits; roles and responsibilities; and compliance.

As part of its Annual Distribution Capital Planning Process[8], ENGLP 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.[9] 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.

These plans are reviewed annually and subject to oversight by EPCOR Utilities Inc.'s Board of Directors.

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.

5.4 Description

The risks identified are:

1. M9 Rate no longer being offered by Enbridge; and
2. Accelerated depletion of local gas production wells.

5.5 Evaluation

M9 Rate no longer being offered

ENGLP is aware that Enbridge Gas has an approved new M17 rate designed to provide transmission service to embedded distribution utilities. ENGLP's view is that this new rate is unfavorable as compared to the M9 rate and does not intend to subscribe to this service. The OEB recently ruled that any embedded distributor who elects to move to an M17 rate will be precluded from returning to its former M9 rate. However, as the Board indicated in its decision on Enbridge's M17 application, ENGLP understands that Enbridge will continue to offer the M9 rate to ENGLP (Aylmer). As discussed in this Gas Supply Plan,

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[8] This process is subsumed within the "Utility System Plan" evidence of the EB-2018-0336 Cost of service rate filing.
[9] EB-2018-0336, Application and Pre-filed Evidence, Exhibit 2, Tab 3, Schedule 1, at page 2.

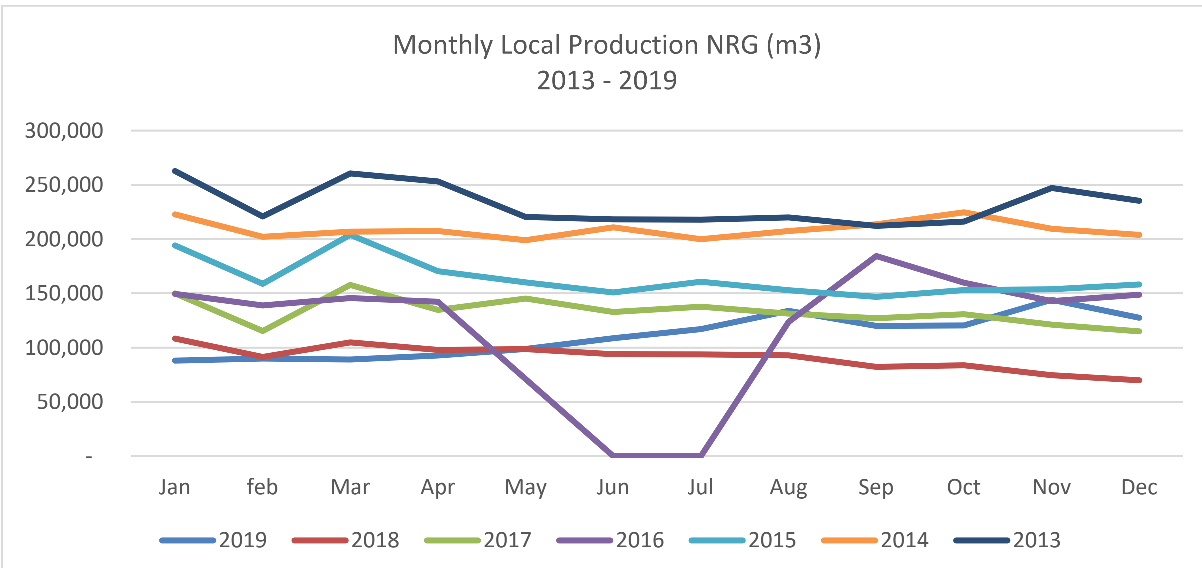
ENGLP (Alymer) intends to stay on the M9 rate.

5.6 Accelerated depletion of local gas production wells

ENGLP retained GSA Energy to identify the remaining production life of the former NRG Corp. wells, as part of its acquisition of NRG. GSA Energy's review identified the significant economic depletion in the remaining production life of NRG Corp.'s wells.

The graph below shows the monthly local production volumes since 2013.

Figure 1 – ENGLP Aylmer Monthly Local Production



The graph illustrates a year over year decline of approximately 16%. ENGLP consulted with Lagasco in order to determine production levels over the planning period. Lagasco confirmed production will continue to decline from these wells.

As discussed earlier, in order to address the risk associated with production decline, ENGLP has contracted for incremental lake gas in order to mitigate potential gas shortages in the South area of the franchise.[10] To further secure reliability of supply, incremental production has been contracted on a firm and not interruptible basis. ENGLP will continue to monitor performance of this incremental supply source.

6. Public Policy Objectives

6.1. Renewable Natural Gas (RNG)

ENGLP understands and supports the development of an RNG market and facilitates inclusion of RNG in its gas supply portfolio. ENGLP recognizes the importance of Greenhouse Gas (GHG)

[10] EB-2018-0336, Application and Pre-filed Evidence, Exhibit 2, Tab 3, Schedule 1, page 15-16.

abatement across the province, as well as the role that ENGLP plays in supporting the achievement of GHG emission reduction targets.

At this time, ENGLP does not hold any RNG supply in its Supply Plan. However, ENGLP has had initial discussions with customers capable of providing RNG into the natural gas distribution system. ENGLP will update the Supply Plan as strategies of a RNG solution are developed and finalized.

6.2. Demand Side Management

ENGLP does not currently offer Demand Side Management in its natural gas distribution system.

6.3. Community Expansion

ENGLP has been actively working to bring secure, reliable and affordable natural gas to unserved communities. A number of customers have requested service and ENGLP has pro-actively responded to those requests.

In 2020, ENGLP received approval from the OEB to serve the community of Salford[11] and to serve three individual ex-franchise customers lying along traversing pipelines.[12,13] ENGLP applies the guidelines as set out in EBO 188 to ensure there is no cross-subsidization between existing and potential new customer connections.

6.4. Federal Carbon Pricing Program

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,* with the following features:
For larger industrial facilities, an output-based pricing system for emissions-intensive trade-exposed ("EITE") industries applied in January 2019. This will cover 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.
As part of ENGLP's compliance requirements with respect to the FCPP, the utility filed its 2019 FCPP application (EB-2019-0101) with the Board on March 8, 2019. The application was approved on July 18, 2019. Similarly, ENGLP has similar applications before the Board to update for 2020 adjustments to FCPP rates.

7. <u>Current and Future Market Trends Analysis</u>

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

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[11] EB-2019-0232, Decision and Order, dated January 16, 2020.
[12] EB-2017-0108, Decision and Order, dated August 15, 2019.
[13] EB-2017-0108, Decision and Order, dated September 13, 2019.

In summary, the Current and Future Market Trends Analysis, concludes there are no major changes expected in the North American natural gas market over the planning period that will shift the fundamental supply and demand dynamics to a degree that will impact the viability of the Supply Plan and its ability to deliver on the guiding principles of cost-effectiveness and reliability and security of supply.

8. Performance Metrics

ENGLP has drafted a performance metric scorecard in order to measure the effectiveness of the Supply Plan.

Performance Metrics-EPCOR Natural Gas LP

OEB Guiding Principle

1. Cost Effectiveness	Performance Categories	Intent of Measures	Measures	Sample	2020	2021	2022	2023	2024
	Policies & Procedures	Demonstrates consideration of alternate Enbridge rates	Annual rate review	C					
	Price Effectiveness	Demonstrates local production a competitive option	Premium to system gas alternative	+/-%					
2. Reliability & Security of Supply	**Performance Categories**	**Intent of Measures**	**Measures**	**Sample**	**2020**	**2021**	**2022**	**2023**	**2024**
	Design Day	Demonstrates ENGPL ability to procure transportationassets required to meet design day demand	Acquired assets to meet design day	1. 100% 2.% Enbridge Overrun Charges					
	Coordination	Demonstrates ENGPL ability to invest in capital distribution required to meet design day demand	Monthly meetings between gas supply & engineering operations	12/yr					
	Communication	Ensure ongoing communications	Communication to ratepayers re material bill impacts	C					
	Diversity	Demonstrate the diverity of the portfolio	1. Firm local gas flow 2. Local production as % of system gas	%					
	Reliability	Demonstrate the reliability of the portfolio	1. Days failed to deliver to customers 2.Days customer interrupted (1)	#					
3. Public Policy	**Performance Categories**	**Intent of Measures**	**Measures**	**Sample**	**2020**	**2021**	**2022**	**2023**	**2024**
	Supporting Policy	Reports public policy in ENGLP supply plan	Plan addesses 1.Community expansion 2. FCC 3. RNG	C					

Notes : C= Compliant

Definitions:

1. Cost Effectivness: 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

2. 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 reciept points to meet planned peak day and season gas delivery requirements

3. Public Policy: The gas suply plan will be developed to ensure that iit supports and is aligned with public policy where appropriate

9. Continuous Improvement Strategies

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

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

ENGLP expects to commence 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 ENGLP believes that at this time, this opportunity is beyond the scope of this gas supply planning period.

10. Appendices

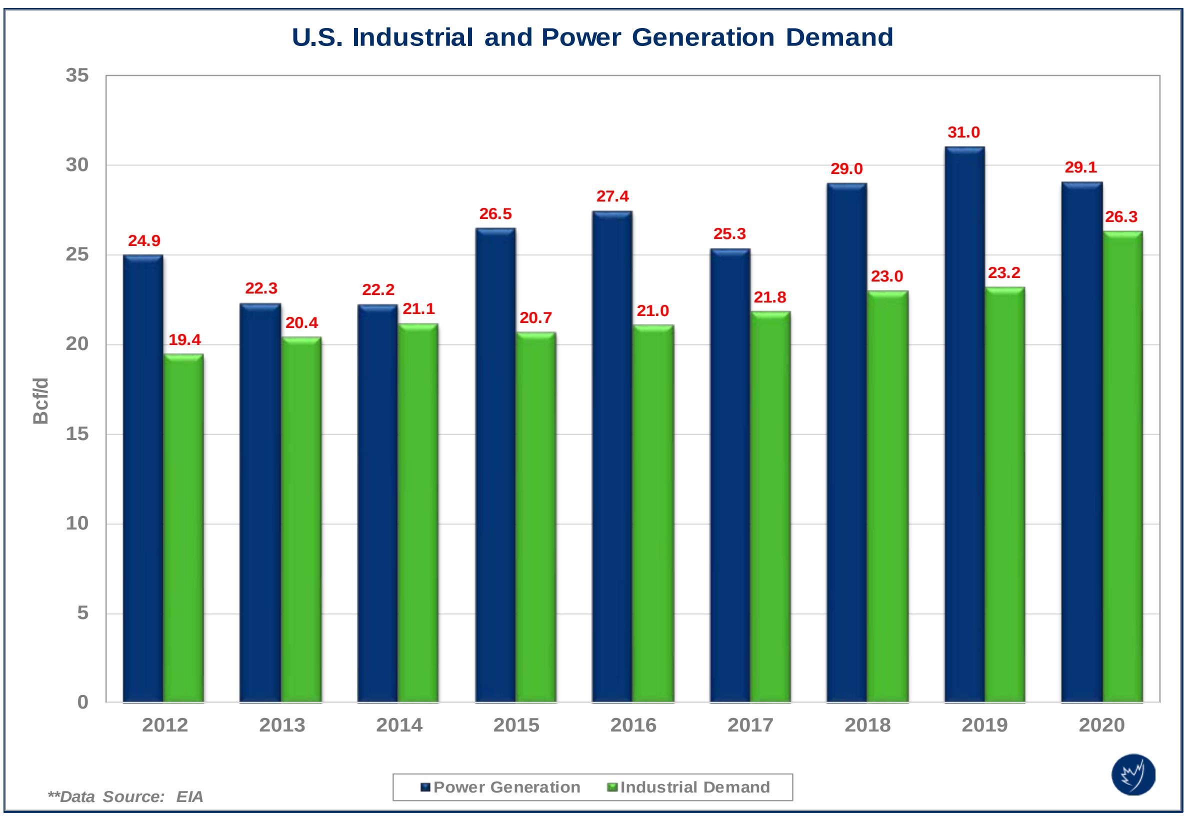
APPENDIX A: CURRENT AND FUTURE MARKET TRENDS ANALYSIS

Current and Future 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 fundamental drivers for natural gas are demand, supply, storage and in a more limited/indirect way crude oil and underlying currency foreign exchange.

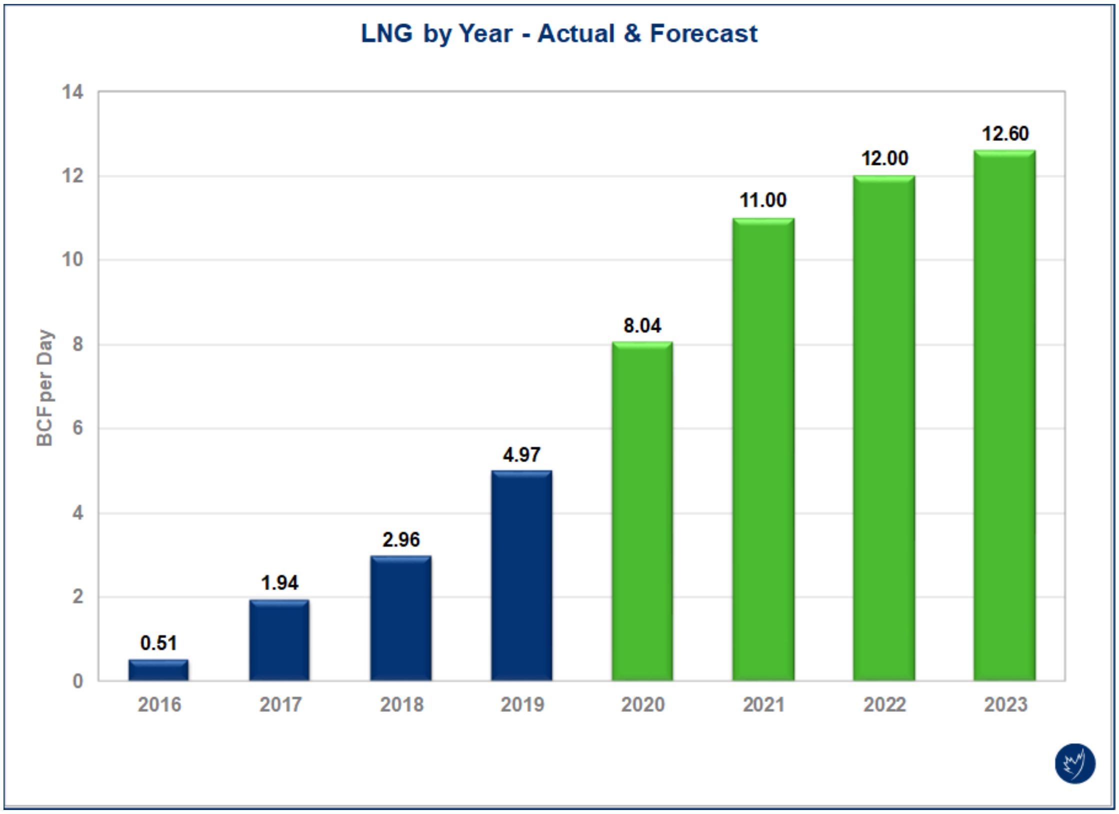
Demand: Impact on pricing - Near term Mildly Bullish, midterm Mildly Bullish

While a mild winter across most of North America resulted in lower demand in the residential and commercial sectors, medium and long term demand growth continues to be seen. United States (U.S.) Industrial demand has grown on average +3% per year over the last 10 years. U.S. gas fired power generation demand shows much more growth (albeit erratic) has averaged 5.6% over the same 10-year period. This is expected to increase in the medium term as jurisdictions are running more baseload hours on natural gas pushing out coal and backing up wind (see figure below).



LNG exports are increasing by 3 Bcf/day from 5 Bcf/day in 2019 to 8 Bcf in 2020. The chart below shows U.S. LNG

Exports since January 2016 when no natural gas was exported. The blue columns are actual volumes while the green columns are figures are an average of 3 LNG export forecasts prepared in January 2020 (see figure below).



Supply: Impact on pricing – Near-term Mildly Bearish (NYMEX) and Mildly Bullish (AECO); Longer-term Mildly Bearish (NYMEX) and Bearish (AECO)

While year over year U.S. dry gas production (supply) growth has been impressive the last two years (12% and 10%), the U.S. Energy Information Administration (EIA) is only forecasting 2020 growth of 3%.

Production in the Marcellus and Utica basins is expected to continue to grow in the three scenarios provided by the EIA keeping supply strong to fill Rover and Nexus pipelines feeding into Ohio, Michigan and Ontario and Tennessee, Empire and National Fuel Gas Pipelines at Niagara and Chippewa. See Figure ZZ, “East” portion of the growth curve as provided by the EIA in its Annual Energy Outlook 2020 released in January 2020. The “East” or the Appalachian region has been the key driver of gas production in U.S. over the last 10 years and is expected to continue for years to come.

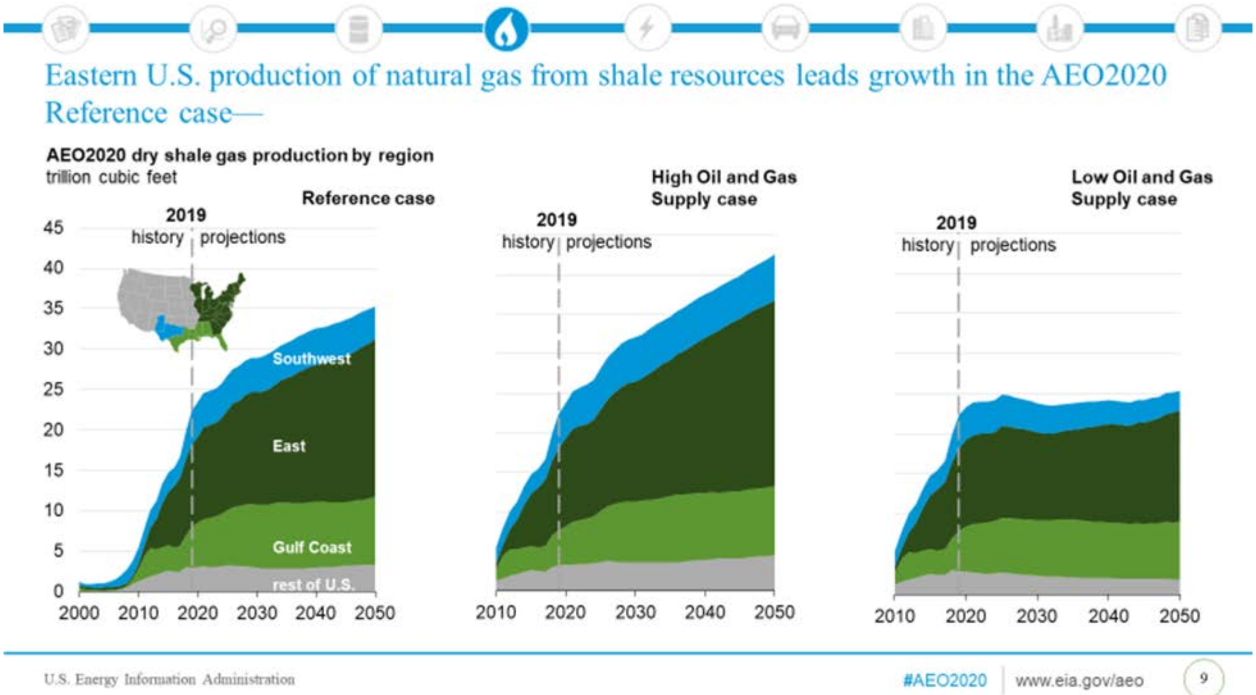


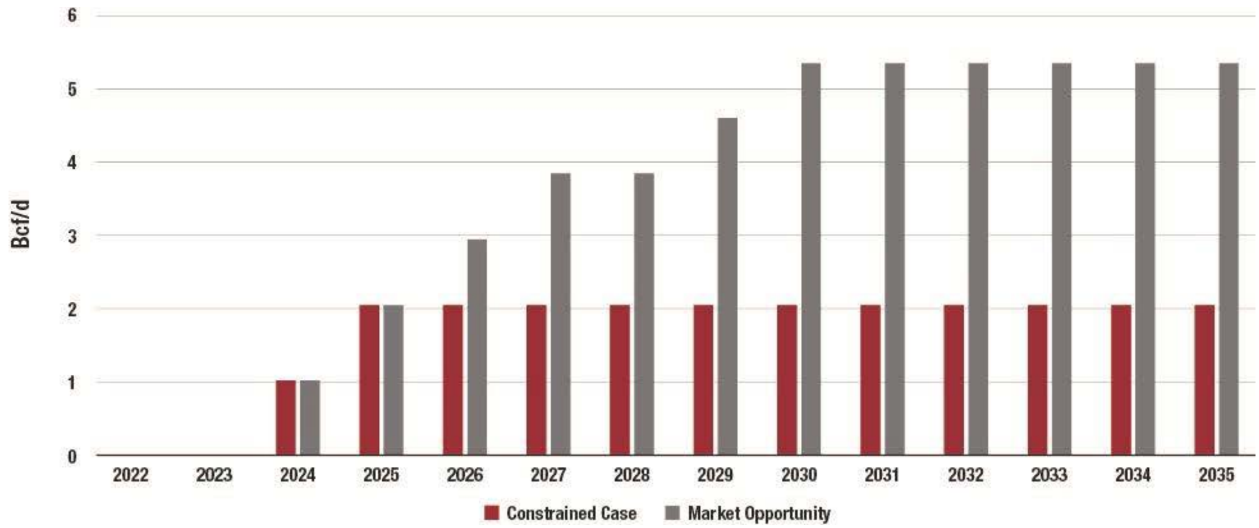
Figure ZZ: EIA Supply Forecasts at January 2020

The Western Canadian Sedimentary Basin (WCSB) production has stagnated due to lack of demand growth or lack of economic access to North American (or world LNG) markets in the last decade however it is poised to grow to meet increased demand primarily via TransCanada Energy's (TCE) Mainline. Like in the U.S., WCBS shale reserves are prolific with deposits in North Montney and Duvernay in NE BC and NW AB resulting in supply that is connected to the Aeco Market via the Nova Gas Transmission Ltd. (NGTL), TCE's gathering and transmission network of pipelines in NE BC and Alberta including its most recent North Montney Mainline Project which gradually has come on-line during this past winter and in spring 2020. In total on NGTL, TCE is implementing a renovation and expansion program at a cost of $6.7 billion scheduled for completion in April 2022 which includes restoring capacity to Empress to primarily facilitate the refill of unused capacity at NGTL's Eastern Gate (TCE's Mainline inlet at Empress and Northern Border's Pipeline's inlet at McNeil).

The Canadian Association of Petroleum Producers (CAPP) in February 2020 released a report titled Canadian Natural Gas: Demand and Production Forecast and Scenario Modelling which identifies their view of WCSB capability to meet their Market Opportunity case to 2035 show significant confidence in growing production, see Figure WW.
The 'Market Opportunity' case utilizes the same outlook for Canadian natural gas demand but incorporates

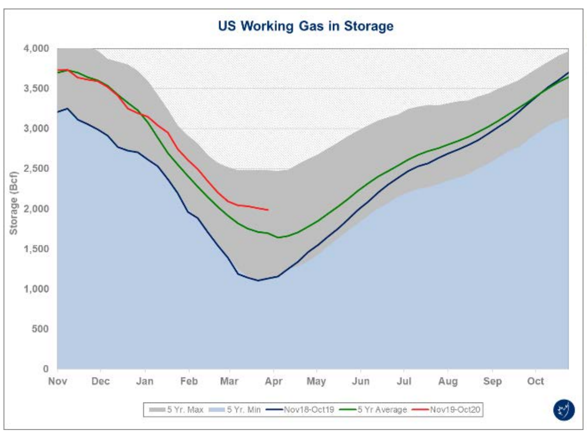
a higher level of net exports to the U.S., that results from a more efficient regulatory framework being implemented that avoids protracted transportation bottlenecks and depressed prices.

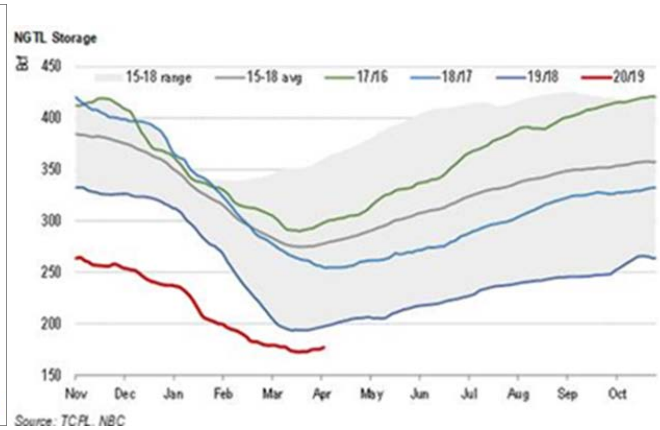
Figure WW – Canadian Natural Gas Production Forecast and Scenario Modelling

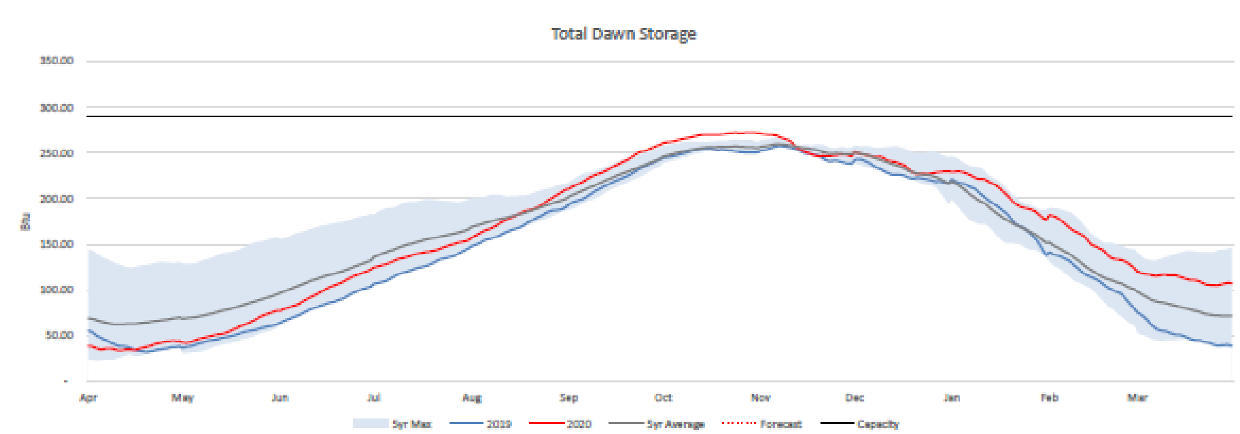


Storage: Impact on pricing – Near term Mildly Bearish (NYMEX and Dawn), Bullish (AECO)

Total U.S. working inventories at March ending fell just below 2.0 Tcf, 14% higher than the five-year average. In EIA's forecast, inventories rise by a total of 2.1 Tcf during the April through October injection season to reach 4.0 Tcf at October 31, which would be the highest end-of-October inventory level on record. In Canada, storage at winter's end in Alberta is setting the 5 year low, whereas storage at Dawn is closer to the 5 year high (see graphs below)

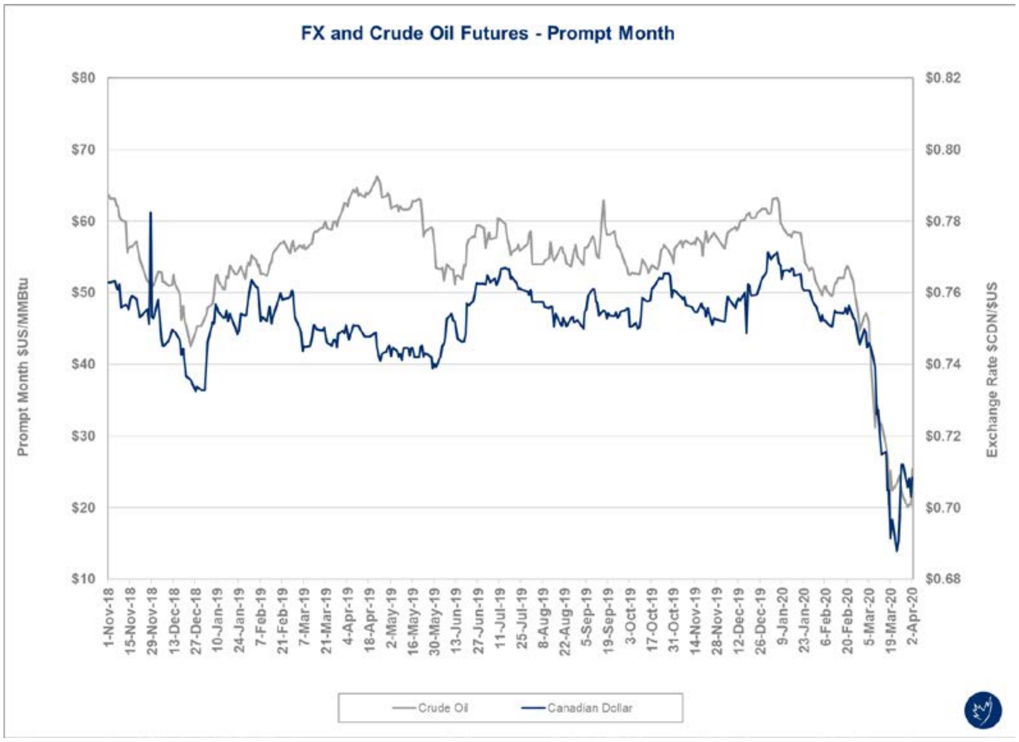


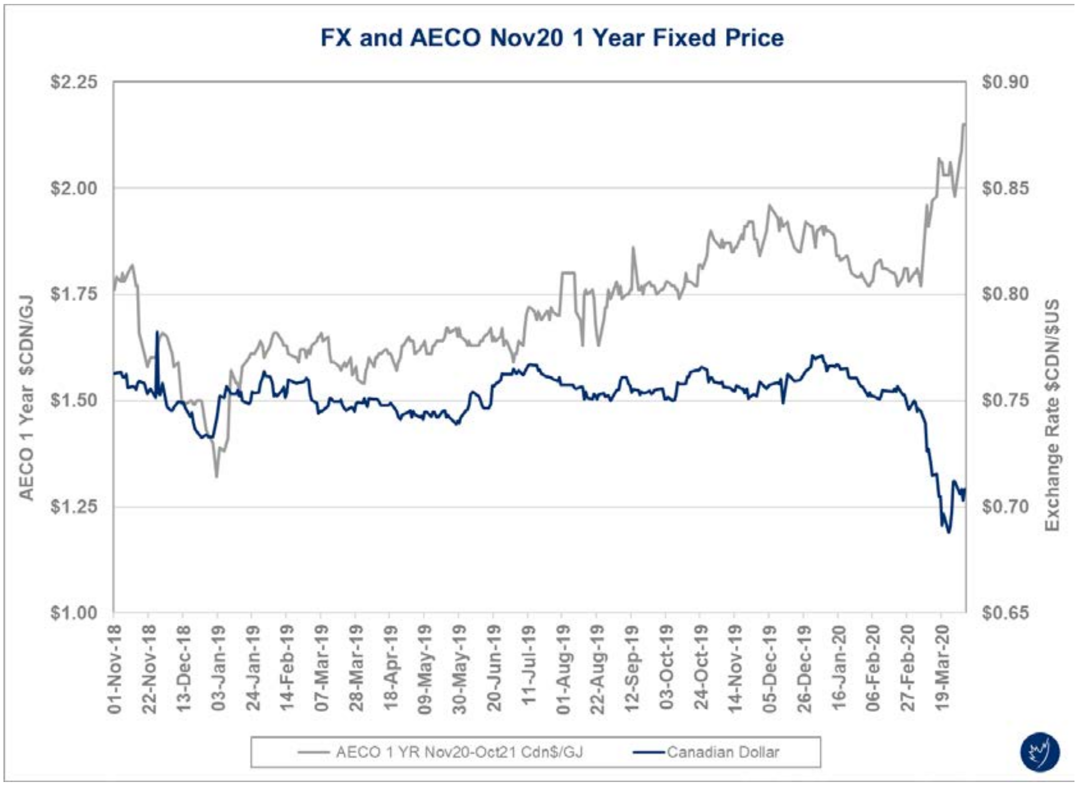




Crude Oil and Foreign Exchange: Impact on pricing – Near-term Mildly Bullish, Longer-term Neutral

The low oil pricing due to oversupply battle between Russia and Saudi Arabia should it continue throughout the summer will impact oil capital programs in the U.S. leading to lower associated gas supply. Also, for the Canadian buyer is to reduce its buying power and thus makes this price impact more bullish. The next two graphs show the impact of crude price drop on the U.S./Canadian foreign exchange and then the impact of the foreign exchange on the price of gas in the WCSB. Mid to long term the influence on natural gas pricing is expected to be minimal in the longer term as crude oil pricing has difficulty finding equilibrium in the $20-$30 U.S./MMBtu price levels.



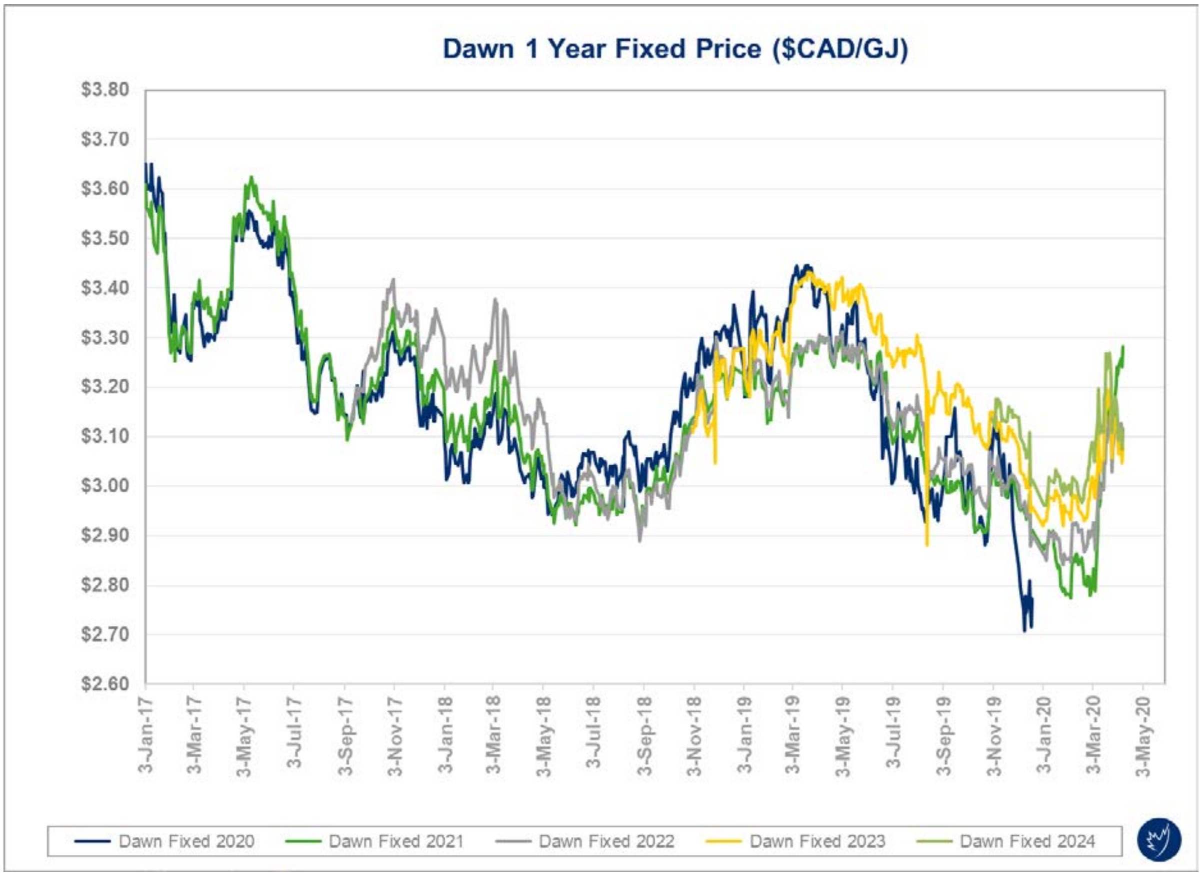


Short Term Summary – Neutral / Bearish (NYMEX and Dawn), Bullish (AECO)

In the U.S., slowdowns in LNG exports, higher inventories (at Dawn as well) at winter's end, and strong shale supplies make NYMEX and Dawn price outlooks favourable in the near term. In the overall context of historical natural gas pricing, AECO term prices are strong which should continue to support investment in gathering and delivery infrastructure as well as supply exploration and development capital expenditures.

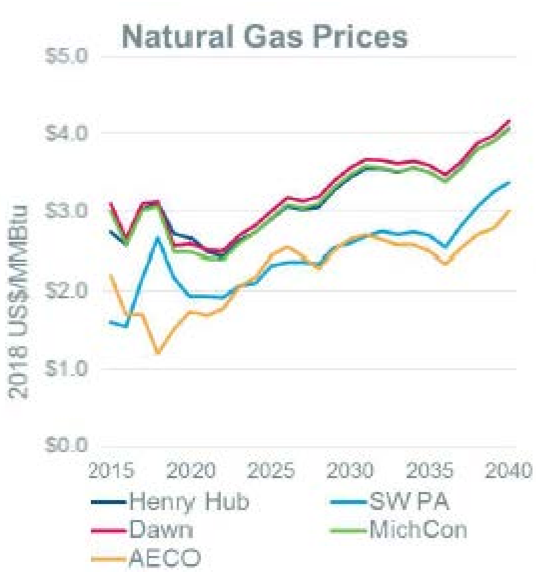
Long Term Summary – Mildly Bullish (NYMEX and Dawn), Mildly Bearish (AECO)

With the expectation of strong LNG exports, continued growth in gas-fired power generation and slowdown of shale gas growth we expect pricing to move modestly upward. This view does not expect the COVID-19 economic slowdown to be long lasting. The landed cost of gas at Dawn is between $2.90 and $3.20 CAD/GJ for the next 4 gas years. This is good value and in a couple of years we do expect prices to be higher (up to 25%) unless U.S. natural gas production reverses its recent trend.



We are looking for AECO prices have the potential to fall as we head into 2021 with increased capacity infrastructure in WCSB on NGTL and TCE Mainline.

As presented in August 2019 at Enbridge's Annual Customer Meeting (found on its website) the below graph shows a forecast of various prices out to 2040 (in $US/MMBtu). It is interesting to note that Henry Hub (NYMEX) and Dawn are expected to follow closely downward in the early 2020's then upward from that point. AECO follows a similar trend post 2020.

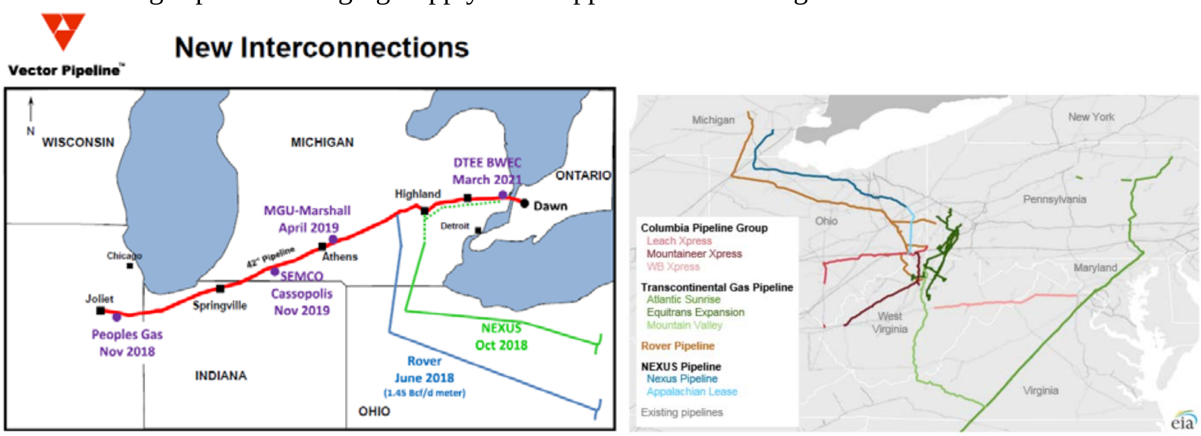


Dawn Market Hub Discussion

Natural gas primarily flows into the Dawn Hub ("Dawn") from the WCSB and from the United States (U.S.) the Marcellus and Utica shale plays in the Appalachian region as well as from the Chicago Citygate (a market Hub with excess supply from WCSB and other U.S. supply regions).

Driven by its robust supply economics and proximity to the U.S. Northeast and Eastern Canadian markets, Appalachian supply now fulfills most of the gas demand in the U.S. Northeast, and had displaced most of the WCSB supply into that region, and in the last few years has made large inroads in Eastern Canada as well. The latter displacements primarily come from the reversal of the TCE's Niagara/Chippewa (N/C) export points in 2012 and 2015 respectively. This accounted for a greater than 2.0 Bcf/d swing in Ontario hydraulics changing from 1.0 Bcf/d of exports at N/C to over 1.0 Bcf/d of imports at N/C. In 2017 the expansion of the Vector pipeline (0.45 Bcf/day of incremental summer capacity) at Dawn has further increased capability to supply into Eastern Canada. This facilitated new pipeline projects such as Rover (3.25 Bcf/d) and Nexus (1.5 Bcf/d) in 2018 and 2019 respectively continue to bring new supplies into the U.S. Midwest and Dawn (See Figure XX)

XX - Existing Pipelines Bringing Supply from Appalachia to Michigan

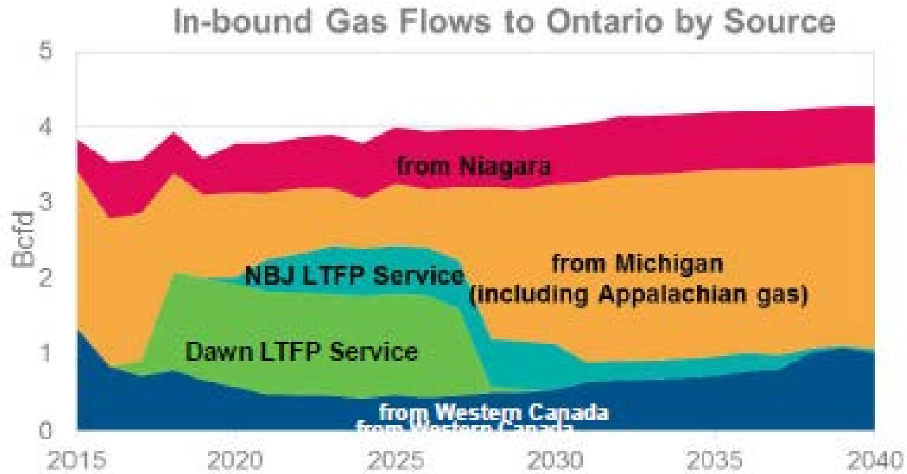


Source: EIA

The caveat to these pipeline developments is that Vector pipeline capacity is not increasing. The last expansion on Vector in 2017, pushed winter and summer capacity to 1.75 Bcf per day. Rover and Nexus will add incremental supply from the U.S. (displacing WCSB gas coming via Chicago supplied by Alliance Pipeline) that will have the potential to add further downward pressure on the Dawn gas price.

Historically, the WCSB has been the major gas supplier to markets in Eastern Canada, but the emergence and rapid development of Appalachian shale supply has significantly increased U.S. supply into Eastern Canada, displacing WCSB gas, however this trend has been dampened.

Effective November 1, 2018 and November 1, 2019 (predominantly) as a result of TCE's first successful Long Term (10 years) Fixed Price (LTFP) Empress to Dawn Open Season of 1.5 Bcf/day of new gas supply came into effect improving Dawn as a source of reliable and reasonable cost supply. Shortly thereafter TCE held another successful LTFP from Empress this time via North Bay Junction as it increased the access of WCSB gas by another 0.3 Bcf/d by 2022. The graph below shows the capacity being used to serve Eastern Canadian markets changing significantly between 2017 and 2019 and then in 2022 and beyond.



The significant aspect of this graph shows that there is excess capacity available to serve the Eastern Canadian markets.

Given the above market outlook and future trends analysis, there are no major changes expected in the North American natural gas market over the planning period that will shift the fundamental supply and demand dynamics to a degree that will impact the viability of the Supply Plan and its ability to deliver on the guiding principles of cost-effectiveness and reliability and security of supply.

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 CV's

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.

APPENDIX B: 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
2024	55,556	54,816	54,085	53,364	52,652	51,950	51,257	50,574	49,900	49,234	48,578	47,930	619,895
2023	65,266	64,396	63,537	62,690	61,854	61,030	60,216	59,413	58,621	57,839	57,068	56,307	728,237
2022	76,673	75,651	74,642	73,647	72,665	71,696	70,740	69,797	68,866	67,948	67,042	66,148	855,514
2021	90,073	88,872	87,687	86,518	85,365	84,227	83,104	81,995	80,902	79,823	78,759	77,709	1,005,036
2020	112,437	103,976	103,013	101,639	100,284	98,947	97,628	96,326	95,042	93,775	92,524	91,291	1,186,882
												Decline Rate	16%

Enbridge (Supply)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2024	4,183,359	3,822,450	2,928,128	1,763,862	675,742	171,115	284,677	480,461	436,346	1,466,377	4,206,738	4,620,864	25,040,119
2023	4,019,729	3,670,024	2,812,393	1,679,624	657,584	144,680	258,689	461,728	420,855	1,403,971	4,017,639	4,456,208	24,003,123
2022	3,860,894	3,521,944	2,699,456	1,597,125	637,867	117,535	231,977	442,556	405,388	1,342,987	3,835,964	4,296,292	22,989,985
2021	3,706,555	3,377,904	2,589,059	1,516,068	616,435	89,419	204,275	422,691	389,707	1,283,157	3,661,157	4,140,790	21,997,217
2020	3,859,267	3,346,901	2,806,945	1,436,145	593,099	60,036	175,282	401,845	373,540	1,224,194	3,492,663	3,989,380	21,759,298

Production C-(Lakeside Production owned by Lagasco)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2024	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104
2023	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104
2022	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104
2021	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104
2020	647,327	755,328	630,790	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	7,725,788

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

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2024	5,195,699	4,741,458	3,938,997	2,473,146	1,206,786	686,024	635,767	830,867	1,142,166	2,472,395	5,181,236	5,625,578	34,130,118
2023	5,041,779	4,598,612	3,832,715	2,398,234	1,197,830	668,670	618,736	820,973	1,135,395	2,418,594	5,000,627	5,469,299	33,201,464
2022	4,894,351	4,461,787	3,730,882	2,326,691	1,188,924	652,191	602,549	812,184	1,130,174	2,367,719	4,828,926	5,319,224	32,315,602
2021	4,753,412	4,330,968	3,633,530	2,258,507	1,180,192	636,605	587,211	804,519	1,126,529	2,319,765	4,665,836	5,175,283	31,472,357
2020	4,619,030	4,206,205	3,540,748	2,193,704	1,171,776	621,943	572,742	798,003	1,124,502	2,274,752	4,511,107	5,037,455	30,671,968

DEMAND FORECAST ANALYSIS

Total Demand

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2024	5,195,699	4,741,458	3,938,997	2,473,146	1,206,786	686,024	635,767	830,867	1,142,166	2,472,395	5,181,236	5,625,578	34,130,118
2023	5,041,779	4,598,612	3,832,715	2,398,234	1,197,830	668,670	618,736	820,973	1,135,395	2,418,594	5,000,627	5,469,299	33,201,464
2022	4,894,351	4,461,787	3,730,882	2,326,691	1,188,924	652,191	602,549	812,184	1,130,174	2,367,719	4,828,926	5,319,224	32,315,602
2021	4,753,412	4,330,968	3,633,530	2,258,507	1,180,192	636,605	587,211	804,519	1,126,529	2,319,765	4,665,836	5,175,283	31,472,357
2020	4,619,030	4,206,205	3,540,748	2,193,704	1,171,776	621,943	572,742	798,003	1,124,502	2,274,752	4,511,107	5,037,455	30,671,968
											Weather Normalized Growth Rate- 3%		

APPENDIX C: 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 ENGLP 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 ENGLP 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 ENGLP 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 ENGLP until September 30, 2020.
Production C	Local gas production wells located offshore in Lake Erie. ENGLP entered into a 5 year term contract effective October 3, 2019 in order to purchase firm gas deliveries from these wells
Rate 1– General Service Rate:	Includes residential, commercial and industrial customers that constitute majority of the customer base in the ENGLP 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 D: ELENCHUS WEATHER NORMALIZED DISTRIBUTION SYSTEM THROUGHPUT FORECAST: 2020-2024 (ATTACHED PDF REPORT)

APPENDIX E: LAGASCO OPERATING SYSTEM AT LAKEVIEW TIE-IN STATION