EPCOR Natural Gas Limited Partnership

2023-2025 Gas Supply Plan

Southern Bruce

EB-2023-0111

Contents

Table of Figures

1. Administrative Information

1.1. Introduction

On October 25, 2018, the Ontario Energy Board ("Board" or "OEB") 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. In June 2020, EPCOR Natural Gas Limited Partnership ("EPCOR" or "ENGLP") filed a three-year Southern Bruce Supply Plan for the period 2020-2023 (EB-2020-0106). In the Staff Report "Review of 2022 Annual Update to EPCOR Natural Gas Limited Partnership's Natural Gas Supply Plan" (EB-2022-0141), OEB staff recommended that EPCOR Southern Bruce continue with a three-year Gas Supply Plan cycle and file its next three-year Gas Supply Plan in 2023 for the 2023-2025 period.

EPCOR has developed the following three-year Southern Bruce 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.

In addition to the Board's guiding principles above, a key consideration in this Supply Plan continues to be **flexibility** and obtaining competitive prices vis-à-vis alternative fuels. Southern Bruce is still a relatively new operation with little historical data; therefore, supply planning in the period covered by this plan is done with limited historical data and consumption profiles based on customers' gas usage in their first few years of service. Thus, there continues to be a considerable focus how the plan can be flexible in cost effectively providing reliable supply to Southern Bruce customers in cases when actual demand deviates from the forecasted demand profile used for planning purposes. This must be balanced with the need to provide a burner tip rate which attracts new customers.

To satisfy the Framework requirements, EPCOR developed a demand forecast that reflects its expected annual load profile over the three year rate period starting April 1st 2023 and ending March 31st 2026. The demand forecast was used as an input in determining the appropriate mix of gas supply purchases given contracted storage and transportation assets.

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 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 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 3-year plan, including upcoming decisions in the 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."

1.2. Significant Changes

This section outlines changes to the 2020 3-year Supply Plan (EB-2020-0161). They are discussed in each section below in detail. The following table summarizes the changes within each section:

Section	Significant changes
3.2. Demand Forecast	Changes to demand forecast using latest available information
5.1. Review of Procurement Execution of Supply Option C (2020-2022)	Review of Supply Option C (2020-2022) against market
Appendix E – EPCOR Southern Bruce Performance Scorecard	Added 3-year average view to scorecard

1.3. Process, Resources, Governance

EPCOR developed an annual supply plan review process which is the starting point for the development of this Supply Plan. A number of variables were considered during this review process, including:

- Gas purchase performance;
- North American natural gas price drivers;
- Consumption pattern (consumption and peak demand) and connection counts;
- Demand driver such as weather and economic conditions; and
- Historical asset utilization rate (storage balance, M17 contract demand utilization, LBA balance).

This Supply Plan was a coordinated effort between EPCOR and ECNG Energy Group, a third-party consultant ("ECNG"). EPCOR procured ECNG for the following scope of services:

1. Develop a customer demand forecast (Demand Forecast)

2. Develop a strategy to acquire the necessary services to meet the Demand Forecast, including:

    a. Natural gas procurement strategies;

   b. Determine and advise on storage and transportation asset requirements;
   c. Ensure the Supply Plan is consistent with the Framework;
   d. Ensure the Supply Plan is consistent with the OEB's Consultation to Review Natural Gas Supply Plans (EB-2019-0137) and the Final Staff Report to the OEB issued on March 26, 2020; and

3. Annually, prepare an update to the Supply Plan (Annual Plan Update) for filing with the OEB.

In addition, EPCOR has also contracted ECNG to execute gas supply procurement, including:

1. Ongoing annual natural gas commodity procurement strategy and execute on a cost effective and reliable basis.
2. Nomination services for its natural system gas portfolio as well as for contract (Rate 16) customers.

Biographies of key ECNG personnel are included in Appendix C and Appendix D.

Gas supply procurement strategies and processes developed for this Supply Plan will be executed by EPCOR and ECNG in a cost-effective manner. In addition to the development of this Supply Plan, there will also be an annual review of the plan, processes, and strategies to identify room for improvements. This review process is aimed for Q1 of every calendar year, and would consider the following:

- Review historical demand, and revise forecasted demand for the upcoming planning period to review and revise forecasting procedures where needed;
- Utilization of storage and transportation assets, and forecast utilization rates in the planning period and identify if existing assets are sufficient to meet deliverability

requirements, and if additional storage or transportation assets are needed to meet future needs;

- Existing purchases and cost consequences of executed supply plans, and review whether existing supply plans are cost effective, flexible, and reliable in meeting demand;

- Review processes and procedures related to procurement and management of gas supply, and identify areas of improvement; and

- Supply plan risk assessment, including supplier performance and credit review.

The review process will aim to identify if additional supply, storage and transportation assets are required to serve projected demand over the planning period. The reviews are assessed against the OEB guiding principles of cost-effectiveness, reliability and security of supply, and public policy. OEB Results of this annual review process is then applied to the supply plan for the upcoming period. If additional resource requirements are identified to serve the changes in gas demand, the review will kick start the procurement process.

In addition to the monthly review, supply purchase decisions are made throughout the year to match changes in demand that deviate from the Supply Plan - for example, connection counts that deviate from the assumptions made in this Supply Plan, weather-related impacts, etc. To address these changes, actual and forecasted price, supply, demand, storage and LBA imbalances for Southern Bruce are reviewed on a monthly basis to determine any adjustments that need to be made in the implementation of the Supply Plan. Improvement to the procurement processes are also flagged in these meetings. EPCOR and ECNG has also developed a number of operational triggers that aim to minimize fees and maximize deliverability.

Lastly, EPCOR has developed operational guidelines and processes for supply planning and procurements that align with organization-wide policies that manages financial risk exposures, credit risk exposures, and contract execution authorities. These governance pieces act as additional layers of assurance to ensure the supply planning and procurement processes are executed in a cost-effective manner that limits risks to the rate payers.

2. Market Overview

2.1. Description of Gas Supply and Asset Options

Construction of the Southern Bruce expansion requires significant distribution and upstream asset investment for security and balancing demand with supply. EPCOR required upstream firm transportation (from Dawn) and balancing from Enbridge Gas Inc. ("Enbridge"), as it is the only service provider that can deliver such services. The EB-2019-0183 proceeding resulted in Enbridge providing M17 firm transportation and balancing services to EPCOR. EPCOR is planning to continue to serve the Southern Bruce franchise area through the M17 firm transportation service provided by Enbridge for the period covered in this Supply Plan.

2.1.1. Supply Option

The options related to gas supply require availability at Dawn by suppliers or for EPCOR to consider reaching beyond Dawn to either supply basins or other market hubs like Chicago. At this time, the supply availability is abundant at Dawn as described in the Market Outlook section below. The connectivity of the Dawn hub to the vast majority of supply basins has resulted in a low basis (difference) between NYMEX Henry Hub – benchmark price for the North American gas market at large – and Dawn (i.e Dawn is a discount to NYMEX Henry Hub). Therefore, obtaining supply in supply basins or market hubs beyond Dawn is not necessary to achieve supply reliability for customers. Price diversity is achieved by contracting options discussed in Section 5.

Three types of physical contracts at Dawn were considered for the Supply Plan: fixed price term purchase, index price term purchase, monthly (spot) and daily "cash"[1] transactions.

---

[1] "Cash" transactions are physical delivery contracts for gas for one to three days at a fixed price. Cash prices reflect market conditions closely at the time of transaction.

Fixed price term purchases are physical delivery contracts where a fixed volume of gas is procured for one or more months, and the price per GJ is constant throughout the term of the contract. For this Supply Plan only fixed price forward period contracts with terms one year or less are contemplated.

Index price term purchases are physical delivery contracts where a fixed volume of gas is procured for one or more months. The price per GJ does change on a monthly or daily basis due to market conditions and how the index is made. The following four indices are considered for the Supply Plan:

- ICE NGX Union Dawn Day Ahead Index (DDAI) in $CAD/GJ converted from $US/MMBtu[2];
- Gas Daily Dawn Daily Index in $CAD/GJ converted from $US/MMBtu;
- Canadian Gas Price Reporter (CGPR) AECO Daily Index 5A plus Fixed Basis[3] in CAD/GJ; and
- CGPR AECO Monthly Index 7A plus in CAD/GJ Fixed Basis.

For this Supply Plan, EPCOR has chosen to transact with ICE NGX Union Dawn Day Ahead Index.

NGX index DDAI is the preferred choice for the following reasons:

- All suppliers contracted with EPCOR use the NGX electronic trading platform which creates the index (ECNG's informal survey of other suppliers at Dawn also predominantly use this platform/index);

[2] Foreign exchange rate are as specified in the contract terms (do we want to say this?). Conversion from MMBtu to GJ based on the SI standard of 1.055056 GJ per mmBtu

[3] Fixed Basis is the fixed price transportation value between Alberta AECO and Dawn markets for the term of the contract at the time of transaction.

- The data is readily available through subscription by EPCOR; and
- The trading data is deeper than Gas Daily (more transactions, more volume used to arrive at the daily index market price).

2.1.2. Transportation Options

Upstream transportation to Dornoch has been secured under the M17 rate for 10 years (EB-2019-0183 proceeding). This is sufficient to access the Dawn hub for supply for the first 10 years of its franchise development. Upstream transportation to Dawn follows the same rationale as the Gas Supply Options section above. For the time horizon of this Supply Plan, there is no cost advantage to contract additional upstream firm transportation in order to secure supply versus buying at the Dawn hub from suppliers directly. Investment in gas supply and associated upstream transportation are not required to serve the franchise in this Supply Plan's time horizon as discussed in the Market Outlook section.

There were no changes considered for transportation options for the past year, and no changes considered for the period covered in this Supply Plan Update.

2.1.3. Storage Options

As an outcome of the EB-2019-0183 proceeding, EPCOR was not offered cost-based storage and related daily balancing for T3 or M9 services, which are available to other embedded parties served by Enbridge in Ontario. The option made available to EPCOR for daily balancing was a no-notice service at market price with +/- 12.5% deliverability on 25,000 GJ of space or the same LBA service offered by TCPL to Enbridge in the TCPL delivery areas WDA, NDA, NCDA, and EDA. Either service was paired with a ten year term 100,000 GJ of seasonal storage service space at market price. EPCOR selected the LBA daily balancing for two reasons. The first is that the service is a regulated service with oversight from the Canadian Energy Regulator (CER). The second is that by actively managing the daily delivery requirement coupled with fact that there are no demand charges associated with the service, it is possible to achieve similar operating flexibility at lower costs versus the alternative balancing option offered by Enbridge.

Regarding seasonal storage, EPCOR desired a storage offering at Dawn that included the ability to make multiple nominations daily either within firm contract parameters or for overrun quantities in attempts to reduce daily imbalances, having more options to balance besides buying and selling gas. There are no storage operators at Dawn other than Enbridge to provide this type of storage service. To acquire storage service in Michigan (the closest market for similar storage services) requires dealing with foreign exchange, import-export rules and additional transportation contracts on at least another pipeline to/from Dawn. Accessing storage and associated transportation to/from Michigan adds additional cost and the longer chain of nominations, which makes intra-day nominations more difficult especially for overrun in the winter. These additional items to manage were considered at this time not appropriate in exchange for the added storage service diversity as the franchise needs for storage for the period covered in this Supply Plan.

There were no changes considered for storage options for the past year, and no changes considered for the period covered in this Supply Plan Update. The existing storage contract have sufficient capacity for the gas supply planning period and EPCOR will not need to contract for additional storage for the period covered in this Supply Plan.

2.1.4. Market-Based Commodity Solutions

From time to time, a scenario may arise where a unique, short term need cannot be resolved through a standard offer. The resolution of these issues often requires solicited or unsolicited non-standard offers.

An example of such a scenario is a winter peaking service, which allows EPCOR to secure additional availability of gas from a supplier for a reservation fee during the winter to nominate additional gas in order to meet demand (at a discount up to the daily reserved volume). In some cases, the cost of such a service can be more economical than holding upstream capacity or purchasing additional deliverability from storage. A second example is where EPCOR contracts for a storage service gas is purchased in the summer and nominates it to a supplier at Dawn in return for a redelivery pattern in the late winter to reduce the amount of day to day gas needed.

As the focus of this Supply Plan is based on serving a new and growing market with significant transportation capacity and storage capacity available relative to current market size expectations, the need for market based solutions is unlikely during the time horizon of this plan and are not taken into consideration for gas supply planning at this time.

In the last three years (2020 to 2022), no market-based commodity solutions were required or deployed.

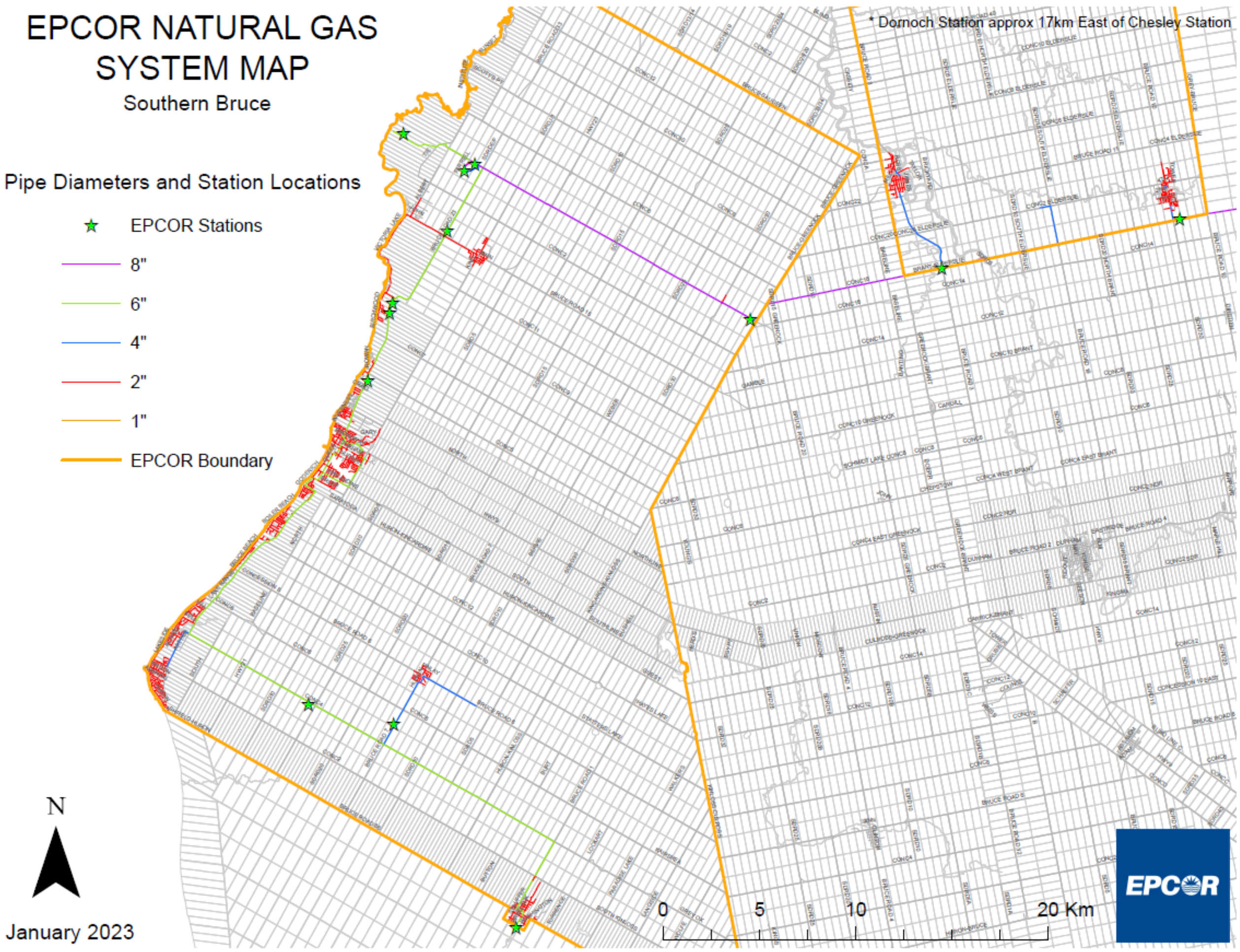
2.2. Market Outlook

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 indirectly crude oil and foreign exchange. ECNG provided the market trending analysis (see).

3. Rate zone Description

The Southern Bruce distribution system is serviced from a single meter interconnect with Enbridge at Dornoch. It comprises approximately 75 km of NPS 8 to 6-inch steel high pressure (“HP”) pipe, 45 km of NPS 6-inch medium density polyethylene (“MDPE”) pipe and 178 km of NPS 4 and 2 MDPE distribution piping (the “Project”) in the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss (collectively, the “Southern Bruce Municipalities”). In December 21, 2022, EPCOR filed notice to the OEB of the completion of the final phase of construction of the Southern Bruce Project which included an in-service date of December 13, 2022 [4]

Figure 1 – Southern Bruce Distribution System Map



The utility will serve two main classes of customers: General Service and Contract Customers. Contract Customers contract for their own natural gas supplies and storage assets to manage fluctuations in demand. As such, the consumption profile of Contract Customers is not included in the demand forecast and Supply Option Analysis.

---

[4] Re: EPCOR Natural Gas Limited Partnership ("ENGLP") Southern Bruce Project Leave to Construct Application – Conditions of Approval (EB-2018-0263): letter dated December 21, 2022

In 2021, EPCOR added a third Contract Customer to the Southern Bruce distribution system. This additional Contract Customer makes up an additional 3.9% of the total M17 capacity bringing the capacity available to system gas customers to 58%. The M17 capacity allocated to the Contract Customers have not changed since the addition of the contract customer in 2021, and is not expected to change for the period covered in this Supply Plan.

An option for Direct Purchase has not been taken into consideration in this Supply Plan for other rate classes as Direct Purchase is currently not offered. On September 1, 2020, EPCOR received an 3-year exemption pursuant to subsection 44(6) of the Ontario Energy Board Act, 1998 (“OEBA”) and Rule 1.5.1 of the Gas Distribution Access Rule (“GDAR”) for an order or orders exempting ENGLP from compliance with Rules 3 and 4 of GDAR. in proceeding EB-2020-0068. In February 2023, EPCOR filed a request for extension with the OEB for to defer the Direct Purchase further program to July 1, 2025.

General Service customers make up the rest of EPCOR’s natural gas system, and are comprised of residential, commercial, and agricultural customers.

In 2022, residential customers made up 75% of EPCOR SOUTHERN BRUCE’s General Service demand profile, and commercial customers made up 16%. 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).

Seasonal agricultural customers, account for the remaining 9% of General Service demand, are expected to use natural gas for production purposes, and as such, their natural gas usage is expected to vary year-on-year depending on crop yield, making it more challenging to forecast demand due to a lack of historical data.

In February 2022, EPCOR received conditional approval for Municipal Franchise Agreements with each of the Municipality of Brockton, the Municipality of West Grey, and the Township of Chatsworth and Amendments to the Certificates of Public Convenience and Necessity for each of the Municipality of Brockton, the Municipality of West Grey, and the Township of Chatsworth (EB-2021-0269. At the time of preparation of this Supply Plan, EPCOR has yet to file the Leave to Construct Application for this project– as such the Supply Plan does not consider the demand associated with the Brockton expansion.

3.1. Annual Demand

3.1.1. Customer Connection Forecast

The forecast captures year-on-year demand growth as more customers connect to the Southern Bruce distribution system. The 2020 Supply Plan assumed the annual increase in consumption volumes were based on the level of customer attachments the utility committed to during the Common Infrastructure Plan ("CIP") process. In June of 2019, EPCOR entered into a design build agreement with AECON Utilities to perform the design, engineering, procurement, construction, testing, purging, substantial completion and final completion of the Southern Bruce Facilities. This included a revised customer connection forecast which compressed the initial three year customer connection forecast into two years (note that the connection forecast is essentially the same as those in the Common Infrastructure Plan (CIP) process by the end of 2021).

Over the past year, EPCOR has observed that the pace of gas-consuming customer additions on the Southern Bruce system has been relatively consistent in the past two years (2021 and 2022). EPCOR has also received customer applications that are expected to drive the growth of system demand at a similar place into mid-2025. The pace of customer additions in 2022 confirms the adjustment made to the customer connection forecast in the 2022 Annual Update. Table 1 shows the changes in customer connection forecasted in the previous three Supply Plans and Update, actual connections in 2021 and 2022, and the adjusted customer connection forecast underpinning the demand forecasts this Supply Plan.

In 2022, the actual customer connections forecast was relatively similar to 2021. In December of 2022, EPCOR officially completed the construction of the Southern Bruce Project[5], and customer attachments are expected to decline as a result in 2024.

Table 1 – Calendar year end Customer connection forecast comparison

Year	2020 GSP (2020-2023) (EB-2020-0106)				2021 GSP Update (EB-2021-0146)				2022 GSP Update (EB-2022-0141)				2023 GSP (2023 to 2025) (EB-2023-0111)			
	Rate 1	Rate 6	Rate 11	**Total**	**Rate1**	**Rate 6**	**Rate 11**	**Total**	Rate 1	Rate 6	Rate 11	**Total**	Rate 1	Rate 6	Rate 11	**Total**
2020	2,249	34	2	**2,285**	179	-	1	**180**	179	-	1	**180**	179	-	1	**180**
2021	3,616	56	5	**3,677**	2,614	40	3	**2,657**	1847	7	1	**1,858**	1847	7	1	**1,858**
2022	4,248	78	5	**4,331**	3,703	56	6	**3,765**	3,112	21	6	**3,139**	3,388	21	5	**3,414**
2023	4,795	87	5	**4,887**	4,792	71	6	**4,869**	4,878	34	7	**4,919**	4,911	27	7	**4,945**
2024					5,039	91	6	**5,136**	5,829	34	7	**5,870**	5,604	32	7	**5,643**
2025									5,829	34	7	**5,870**	5,800	36	7	**5,843**

3.1.2. Demand Forecast

To develop a natural gas supply portfolio, EPCOR first constructed a demand forecast that reflects its expected customer profile throughout the year over a three-year horizon from Planning Year 2023 to 2025 (April 2023 to March 2026). This first step ensures that EPCOR procures an efficient volume of natural gas commodity and storage assets. As EPCOR's customer base have rapidly expanded since operations began in 2020, the demand forecast must continue to be sufficiently flexible to mitigate risks associated with a scenario where actual demand growth significantly deviates from the forecast.

Since the 2022 Supply Plan Update, a number of aspects of customer demand have significantly deviated from both the assumptions made in the CIP as well as the 3-year Supply Plan filed in 2020:

[5] Re: EPCOR Natural Gas Limited Partnership ("ENGLP") Southern Bruce Project Leave to Construct Application – Conditions of Approval (EB-2018-0263): letter dated December 21, 2022

- Significant deviations in customer connection number and pace over the last 3 years, particularly for Rate 1 residential, Rate 1 commercial and Rate 6 large commercial customers,
- Significant deviations in average customer consumption, especially for residential customers, and
- Rate 11 grain dryer with significantly different consumption pattern.

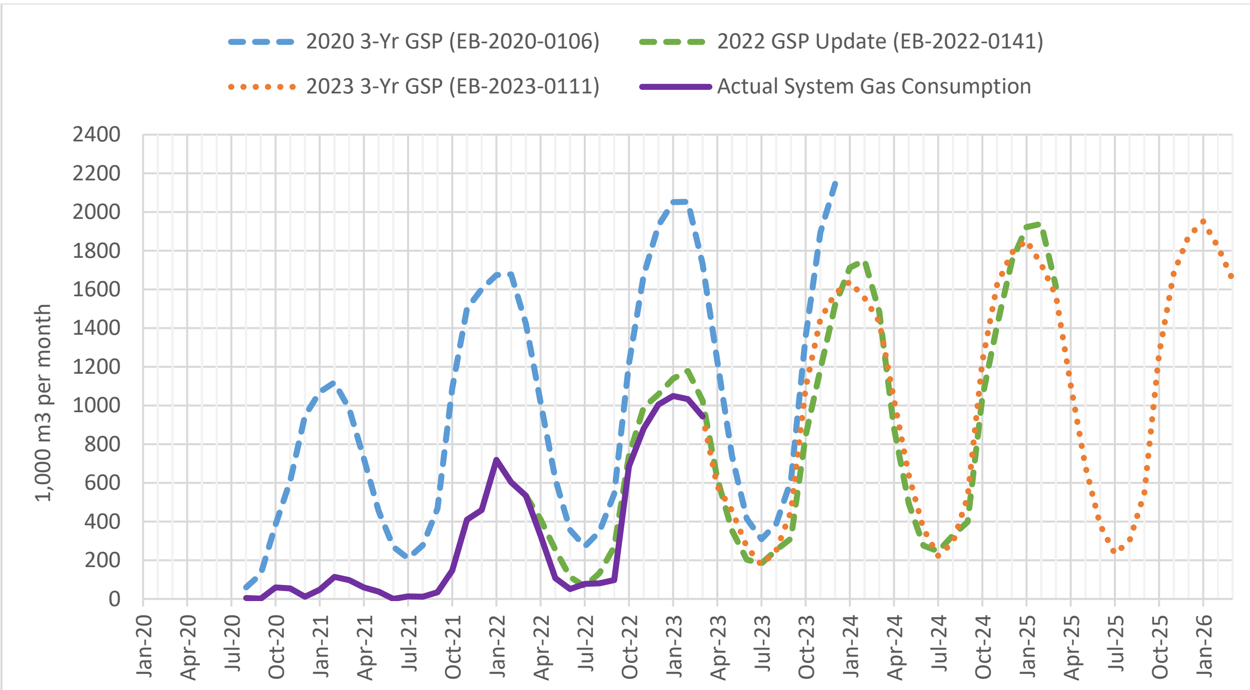
Southern Bruce customers are categorized into four rate classes:

- General Firm Service Rate 1
- Large Volume General Firm Service Rate 6
- Large Volume Seasonal Service Rate 11, and
- Contracted Firm Service Rate 16

As Rate 16 contract customers procure their own supply and manage their own storage, the focus on the Demand forecast is Rates 1, 6 and 11.

The 3-year forecast customer conversion in this Supply Plan reflects the customer applications received up to February 2023, as well as the forecasted pace of daily customer conversions as discussed above. As shown in Figure 2, demand forecast in this update does not deviate significantly from the forecast in the 2022 Annual Update.

Figure 2 – Demand Forecast Comparison

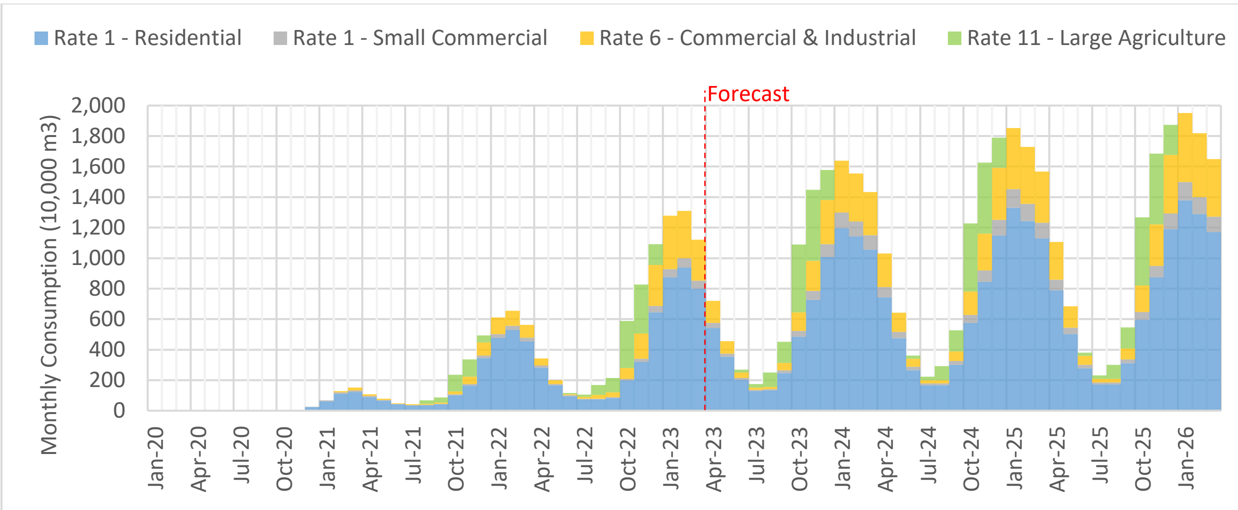


EPCOR will continue to review customer consumption patterns and expand on these findings in future Supply Plan Update filings.

For residential and commercial customers, the annual forecast was further adapted to monthly volumes by applying the monthly percentage of annual CIP-based usage from the OEB Calculator. For large agricultural customers and grain dryers, monthly breakdown was determined through a consultative process, where the annual CIP-based usage was broken down to monthly profiles based on information received by customers on their existing energy needs. The actual and forecasted average day volume per month broken down by each customer type is shown in Figure 3.

As actual consumption in 2022 did not deviate significantly from the consumption forecast in the 2022 Supply Plan Update (which used the assumptions highlighted above), this Supply Plan continues to use the assumptions highlighted above in the monthly breakdown.

Figure 3 - Forecast Monthly General Service Demand, by Customer Type



At current times the demand forecast in this 3-year Supply Plan does not include potential impacts of future Demand Side Management ("DSM") programs. As per the OEB Staff Report for the Review of the 2022 Annual Update, OEB Staff expects EPCOR to submit its first DSM proposal for Aylmer in its next cost of service filing. EPCOR plans to develop its DSM program for the Aylmer franchise prior to developing a DSM program for the Southern Bruce Franchise.

3.1.3. Design Day Demand

EPCOR's Contract Demand under the M17 was based on the expected capacity required to meet peak day conditions in EPCOR's Year-10 gas flow, which is 141,072 m^3 per day (or 5,486 GJ per day) for General Service customers. An additional 86,827 m^3 per day (or 3,377 GJ per day) is currently reserved for Contract Customer that supplies their own gas and manages their own storage).

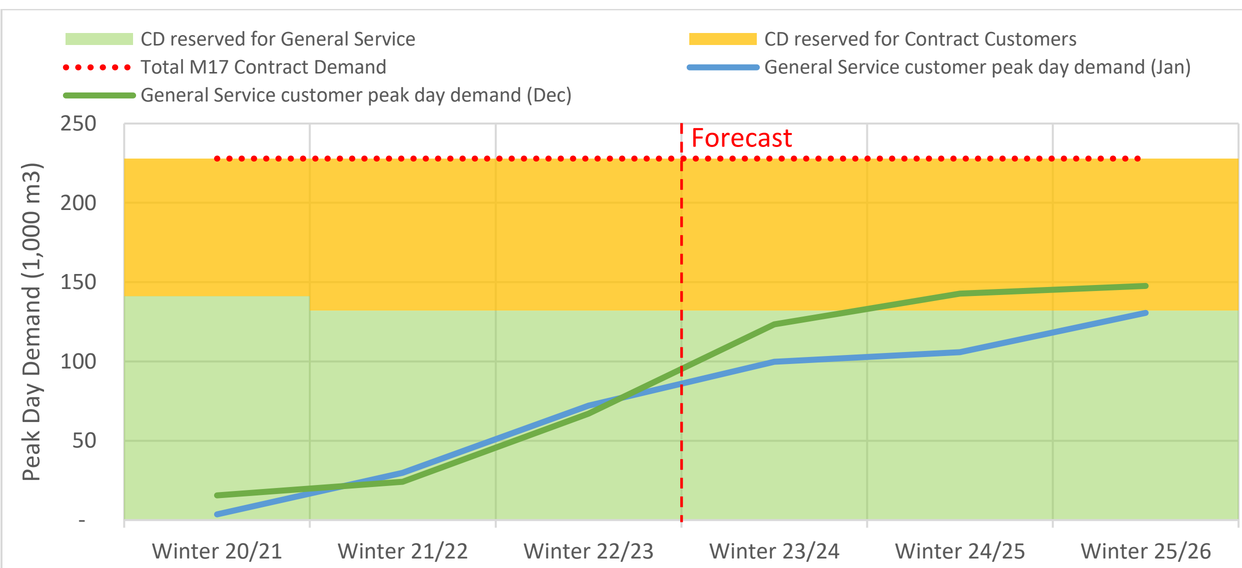
In December 2021, an additional Rate 16 Contract Customer was added to the Southern Bruce distribution system, and a further 8,997 m3/d, or 3.95%, of the overall M17 capacity is now reserved for Contract Customers.

The analysis for Design Day demand in this Supply Plan update follows the methodology used in the 2022 Update, which Board Staff agreed was appropriate in their Review of the 2022 Annual Update.

While design day peak for General Service customers is not expected to exceed the M17 capacity reserved for General Service customers in January for the period covered in this Supply Plan, there is a risk that if each dryers were to run on the same day during a cold day before December 15th, the General Service daily consumption for that day could exceed the capacity allocated to this group of customer.

Figure 4 below shows the expected January and December peak day demand in compared against the M17 contract demand, and the portion of that contract demand apportioned to General Service customers. For general service customers that are not grain dryers, December peak day is modeled to be 0.72% of average annual consumption.

Figure 4 – January and December Forecast Peak Day Consumption vs M17 Contract Demand



Based on the peak January demand forecast shown in Figure 4, EPCOR is not expecting to make full use of the Contract Demand in the three-year planning horizon covered by this Supply Plan Update. By 2026, January peak day demand for General Service customers is expected to be approximately 98.9% of the contract demand reserved for General Service customers. However there is a risk by December 2024 that grain dryer consumption could push single day general service demand above the M17 capacity reserved for General Service customers, given the number of existing Rate 11 grain drying customers and forecasted additions in the next 3 years. EPCOR will continue to monitor consumption during the drying season. Furthermore, contracted storage assets with 1,200 GJs of firm withdrawal rights during the winter period, as well as the LBA agreement with allows for an additional +/- 2,111 GJs of daily imbalance between supply and consumption, are more than sufficient to address any concerns related to deliverability and reliability of supply during peak days within the planning period.

Note that the risk of a General Service Customer peak day in December remains low. In order for this situation to occur, heating degree days prior to December 16th (i.e. before EPCOR can interrupt grain dryer customer consumption under Rate 11) would need to be near-peak day demand, and all grain dryers on the system would have to be running at full capacity on the same gas day. Based on this low risk, it is not cost effective for EPCOR to contract for capacity for a relatively unlikely event. EPCOR has proactively initiated discussions with Enbridge on options for procuring additional firm deliverability during the grain drying season. Further, as Board Staff noted in their Review of 2022 Annual Update, EPCOR can insure deliverability through M17 overrun during the grain drying season.

At current times the Design Day Demand in this 3-year Supply Plan does not include potential impacts of future Integrated Resource Planning ("IRP") projects. As per the OEB Staff Report for the Review of the 2022 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 Southern Bruce for the period covered by this Supply Plan.

4. Current Portfolio

4.1. Commodity Portfolio

EPCOR plans to procure all supplies at the Dawn Hub for Southern Bruce as per ECNG's recommendation as part of the market outlook analysis. Southern Bruce's system supply needs are a small fraction of the Dawn market. For the period covered by this Supply Plan, Southern Bruce's winter system gas demand is expected to average less than 3,000 GJ/d – this represents approximately 0.003 Bcf/d of demand relative to the Eastern Canadian market demand of approximately 4 Bcf/d – EPCOR's portion then represents less than 0.1% of overall Eastern Canadian market demand.

The supply and demand dynamics at Dawn are expected to make it a viable source of supply for EPCOR's base supply and balancing supplies for the following reasons:

1. Dawn has excellent connectivity to the large and small basins of supply in North America;
2. The stable outlook for supply in Appalachia and Western Canadian Sedimentary Basin (WCSB);
3. There is excess capacity to Dawn to access these supplies; and
4. EPCOR's demand for supply will have no material impact on the Dawn market overall.

Based on the above, the Supply Plan will have the ability to deliver on the guiding principles of cost-effectiveness, reliability and security of supply. Further analysis is provided in Section 6.

4.2. Transportation Portfolio

EPCOR's M17 contract with Enbridge is the only Transportation Asset relevant for Southern Bruce during the period covered by this Supply Plan. EPCOR has contracted 227,912 m^3 per day of capacity to deliver gas from Dawn to the Dornoch Interconnect, which is sized to meet peak day demand in Year 10 (2028). EPCOR expects the transportation capacity to be more than enough to reliability meet gas demand to all Southern Bruce customers within the planning horizon.

The M17 transportation contract includes a provision for daily balancing which is facilitated by a separate Load Balancing Agreement (M17 LBA) contracted service, which is described in Section 4.4. EPCOR considers the M17 LBA another tool that can be used in the Supply Plan to ensure reliability and cost-effectiveness of supply. See Section 3.1.3 on EPCOR's approach to addressing potential dryer peak day demand for the period covered in this Supply Plan.

4.3. Storage Portfolio

EPCOR has contracted for storage from Enbridge as a key tool to manage price risk and ensure supply reliability to customers by managing variances between supply and demand. In order to avoid the situation occurring where large volumes of gas need to be purchased from the cash market, EPCOR forecasts Baseload and month-to-month purchase requirements in coordination with estimated storage withdrawal targets each month, such that the maximum deliverability from storage could be maintained until the beginning of March given a normalized weather scenario.

EPCOR has contracted for 10 years of seasonal storage service (LST) with a maximum storage balance (MSB) of 100,000 GJ (100 TJ), a standard offering to its unregulated terms and conditions which includes no firm injections in September and October and no firm withdrawals in April and May. Daily firm injection deliverability is 0.75% of MSB (750 GJ/d) when inventory is below 75% full, then the daily firm rights drop down to 0.5% of MSB (500 GJ/d) when inventory is above 75%. Similarly, daily firm withdrawal ability is 1.2% of MSB (1,200 GJ/d) when inventory is above 25%, then the daily firm rights drop down to 0.8% of MSB (800GJ/d) when inventory drops below 25%. The impact of these firm deliverability rights on the Supply Plan is noted below in the Description of the Supply Options section.

When supply exceeds demand, EPCOR will store the excess supply in its contracted storage account on a planned basis and in the M17 LBA on an unplanned basis described in the section below. Conversely, when demand exceeds supply, EPCOR will use this stored supply to service the deficiency. Storage also enables EPCOR to procure gas at times of the year (typically in the summer) when the price of gas is typically lower and/or less volatile. It should be noted that seasonal storage is not allocated to Contract Customers.

Given the supply/demand modeling conducted as part of this Supply Plan, EPCOR has assessed that the 100,000 GJs of seasonal storage in combination with baseload and month to month firm supplies is sufficient to meet deliverability required within the planning horizon. The current contracted storage will cover approximately one-third of expected winter demand for the threes winters covered in this Supply Plan. Given EPCOR's current and proposed Supply Option (purchasing 50% of expected winter demand as seasonal fixed priced contracts), the current storage contracted translates to an exposure of approximately 15% of system gas winter demand (December to March) at either prompt month purchase of index price purchase. Having a portion of expected winter demand not covered by storage or term purchases allows for additional flexibility in gas procurement – for example, in winters where actual demand is lower than forecast, it will still allow EPCOR to maximize the use of storage withdrawal for the winter season.

4.4. Daily Balancing Management

The M17 transportation contract includes a provision for daily balancing which is facilitated by a separate M17 LBA contracted service. The M17 LBA enables EPCOR to manage daily mismatches between supply (confirmed nominations) and demand (measurement estimate) at the Dornoch Interconnection Point and eliminate the accumulated imbalance on the next earliest gas day to the best of its ability. EPCOR considers the M17 LBA another tool that will be used in the Supply Plan to ensure reliability and cost-effectiveness of supply.

The three Supply Options reviewed in Section 5 assume that on a daily planned basis when purchased gas exceeds consumed gas, the planned excess gas first maximizes the use of the firm injection rights. Excess gas remaining after confirmed storage injection is captured as an injection into the M17 LBA as a daily imbalance and is added to the cumulative imbalance. Demand in excess of planned purchased gas and maximum allowed amount withdrawn from storage is captured as a daily imbalance and a withdrawal from the M17 LBA cumulative imbalance. If in case storage injection and withdrawal rights are not sufficient in bringing the M17 LBA into balance, spot purchases and sales are then considered. Contract customers, are apportioned a share of the M17 LBA and are responsible to manage their own supply-consumption imbalance.

Also available is the HUB service offered by Enbridge. While this pay-per-use service is interruptible, it can be useful during low interruption risk periods of the year. For HUB injections, the low risk periods are December through August. For HUB withdrawals the low risk periods are May through January. The HUB will likely be used on a short term basis only to pack and draft at minimal cost within a month or from one month to another, either in the middle of the summer or winter, to complement the use of the M17 LBA avoiding larger balancing costs during those short term periods.

4.5. Unutilized Capacity

During the period covered under this Supply Plan, EPCOR expects M17 transportation capacity will not be fully utilized in winter until the last winter covered in this Supply Plan (Winter 2025/26). As EPCOR does not currently have the ability to assign its excess transportation capacity to another party (EPCOR is the only party that will be taking the gas at the Dornoch Interconnect), EPCOR will have unutilized transportation capacity for which costs will not be fully recovered from the in the planning period. In its rates application (EB2018-0264) EPCOR applied for and was granted a Storage and Transportation Variance Account for Rates 1, 6 & 11 (“S&TVA Rates 1, 6 & 11”). This account provides for EPCOR the ability to defer the recovery of the additional capacity EPCOR was required to contract with Enbridge initially in order to provide service to its customer base in future years. Accordingly, this under recovery will accrue in the S&TVA Rates 1, 6 & 11 account.

EPCOR does not expect any unutilized storage capacity during the period covered in this Supply Plan. The Supply Plan takes into account the full 100,000 GJs of contracted storage capacity and will utilize storage to its fullest capacity to ensure deliverability and supply cost stability.

5. Supply Option Analysis

5.1. Review of Procurement Execution of Supply Option C (2020-2022)

In EPCOR's 2020 3-year Supply Plan (EB-2020-0106), EPCOR presented three Supply Options and chose Option C as the most appropriate Supply Option based on the results of the risk mitigation analysis. Option C was chosen for the planning horizon due to superior price risk management compared to the other two Options presented in the 2020 Supply Plan, especially in scenarios like the Winter 2013/2014 polar vortex where Dawn Day Ahead Index saw very severe price spikes. Option C also allows for a good level of flexibility in the ability to adjust supply to actual demand – baseload volumes are relative to seasonal demand, meaning that they are low during low consumption months in the summer reducing the risk of over contracting. Higher baseload in the winter time also have a lower risk of over contracting as storage withdrawals can be readily adjusted down if demand is lower than expected – for example, due to warmer than normal temperatures.

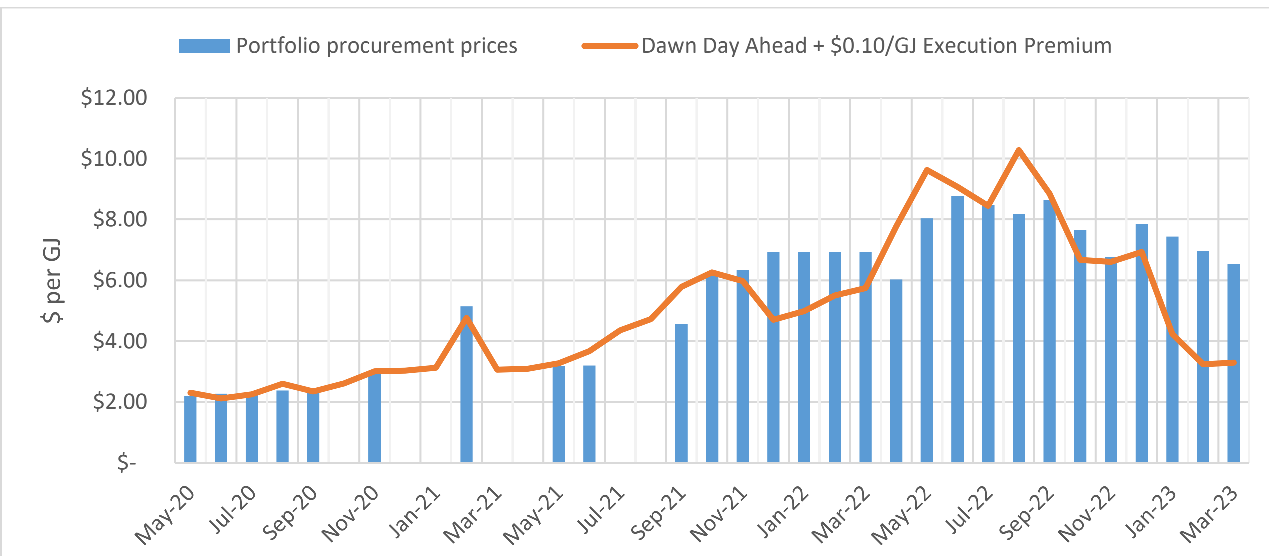
In the execution of the procurement plan, a number of adjustment had to be made over the past three years due to delays in customer connections as well as lower average consumption compared to what was contemplated under the CIP:

a) Reduction in procurement volume compared to
b) A shift away from purchasing gas at AECO
c) A shift away from purchasing gas at Dawn Day Ahead Index

In Board Staff's review of EPCOR's 2022 Annual Update to the Supply Plan, there were no concerns with the adjustments EPCOR made to its procurement plan. Board Staff asked for a comprehensive evaluation of the price difference between forward fixed-priced purchases EPCOR made compared to alternative procurement options available at the time.

The following section compares EPCOR's monthly actual portfolio rate ($ per GJ) to the Dawn Day Ahead Index plus a 10 cents per GJ execution premium. The Dawn Day ahead index is indicative of what EPCOR would have purchased at market without entering into fixed priced contracts.

Figure 5 – Portfolio Commodity Rate compared against Dawn Market Prices



In comparing EPCOR's portfolio costs to the Dawn spot price, the portfolio costs track the spot price quite closely with the exception of this past winter. Market views shifted significantly from over the winter period and a summary is provided in Table 2 below.

EPCOR would note that had prices spiked as in the winter polar vortex of 2013/2014, the portfolio methodology would have protected consumers from these spikes which aligns with EPCOR's initial strategy in selecting Option C and its guiding principles of cost-effectiveness and reliability and security of supply.

Table 2 – Market Outlook changes over Winter 2022/23

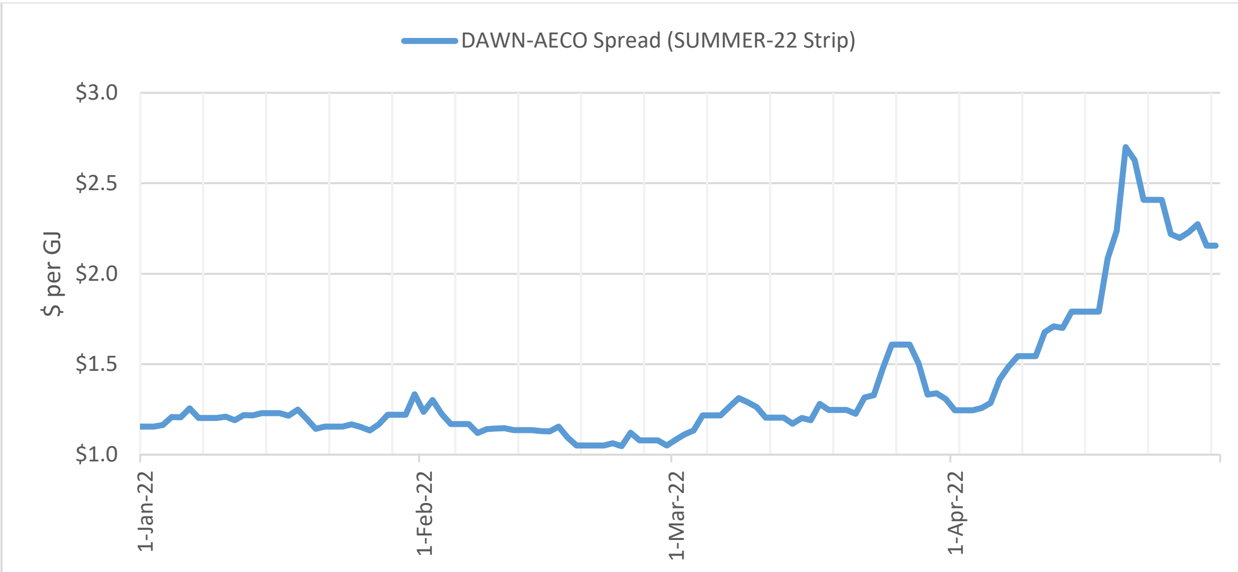
Indicator & Key Drivers	Market View @ November 2022	Market View @ March 2023
US Storage (vs 5 yr avg)	Modest surplus (0-50 Bcf) heading into winter	Large surplus ~350 Bcf at mid-March
US Weather vs Normal	3.3% colder vs 21/22 winter; 2.8% colder vs last 3 winters	January & February warmest in US in 17 & 10 years respectively
Freeport LNG Restart	Expected by end of 2022	Now expected sometime in April (diff of 175-255 Bcf)
US Supply (& Canadian)	Choppy growth started to arrive ~97 Bcf/d; CDN supply strong 17-18 Bcf/d	Few freeze-off events and sustained 97-98 Bcf.d US; CDN supply 18+ Bcf/d

Source: ECNG

As noted above, EPCOR's gas procurement execution deviated from the Supply Plan in the last three years due to the exclusion of AECO purchases. In Option C of the Supply Plan, AECO summer seasonal strips was planned for 50% of the expected summer demand (including storage injection). EPCOR has opted to fulfill summer strip purchases at Dawn fix instead due to the lower Dawn Prices at the time as well as to avoid high volatility of AECO prices.

Additionally, in order for EPCOR to incorporate AECO 5A index pricing into its portfolio, EPCOR would need to fix a portion of the price above the 5A index price, based on the price difference between AECO and Dawn price for the contracted term at the time of contract, reflecting the notional value of transportation. Due to uncertainty in EPCOR's system demand, EPCOR deemed that fixing this notional transportation value introduced unnecessary risk to the portfolio.

Figure 6 – Dawn AECO Spread for Summer 2022 (May 2022 to September 2022)



5.2. Design Day Analysis

As described in Sections 3.1.3 and 4.2, EPCOR ensures there are sufficient transportation assets to serve Southern Bruce's winter (January) peak day demand within the planning horizon. While a portion of the transportation capacity from Dawn to Dornoch is reserved for the Rate 16 Contract Customers, EPCOR has included unauthorized over-run charges in its Rate 16 tariff to protect deliverability to its General Service customers during peak days. In addition, the M17 LBA agreement provides an additional safeguard to ensure availability of supply.

5.3. Average Day Requirement

This section focuses on procurement options and strategies EPCOR has contemplated and evaluated to meet Southern Bruce's expected average day demand for the planning horizon. The following operating assumptions apply for each Supply Option considered:

1) Between April and September of each year, supply would be procured to meet both monthly demand and maximize firm injection rights to fill contracted storage by

September 30th (last day of firm injection right given EPCOR's storage contract). To fill the contracted storage requires 150 days to fill (100 days of 750 GJ/d plus 25 days of 500 GJ/d). EPCOR elects to start firm injections in May instead of April, as a colder than normal April can increase market prices, resulting in higher weighted average value of gas in storage.

2) October and November months have no firm injection rights, so only month to month or spot gas are purchased to satisfy demand in the previous 3-year gas supply plan. Given that EPCOR has some consumption history in the 2022 shoulder season, EPCOR will plan to have some strip purchases covering a portion of forecasted demand in these months. EPCOR will continue to utilize storage withdrawals and the M17 LBA to supplement supply as needed on days with higher than expected demand (for example, during higher consuming days when Rate 11 grain dryers are consuming gas).

3) Commencing December 1st, firm withdrawal rights from storage are fully utilized to meet winter demand when baseload supply and month to month supply are insufficient to meet daily demand. In order to maintain highest deliverability in January and February, the plan assumes an average day withdrawals of 1,000 GJ/d during those months and maintaining MSB (please define) just above the 25% level at March 1 each year. This maintains maximum deliverability from storage for January to March in the event of a persistently cold January and February. If either colder weather or customer connections do not materialize, month to month purchases will decrease accordingly.

ECNG worked with EPCOR to build a customer commodity portfolio tracking model that tracks and forecasts demand, supply and resulting storage positions (net of fuel requirements), and potential triggers for LBA balancing requirements due to daily supply-demand mismatch. The inputs will include anticipated future connections by rate class, ongoing regression analysis for heat sensitive demand forecasting, near term weather forecasts to estimate demand plus known supply acquired, planned supply base scenarios, and resulting storage and LBA positions.

Option C from the 2020 3-Year Supply Plan performed well from the perspective of meeting the guiding principles of cost-effectiveness and reliability and security of supply. Additional consideration include flexibility and burner-tip price competitiveness in order to address the start- up nature of the utility and to attract new customers. . For this Supply Plan, EPCOR introduces 3 additional options to compare to Option C:

Option 1 (previously Option C): A mix of month to month index purchases and seasonal baseload purchases (mixed of AECO index and Dawn fixed price), with AECO 5A+ seasonal strip covering 50% of forecasted system gas and storage injection summer demand (May to September), and Dawn fixed priced seasonal strip covering 50% of forecasted total winter demand (December to March).

Option 2: Same as Option 1, but summer seasonal strips are also purchased at Dawn fixed price.

Option 3: Same as Option 1, with an additional annual baseload Dawn fixed price purchases.

Option 4: Same as Option 3, but summer seasonal strips are also purchased at Dawn fixed price.

Each of these options are analyzed below. It is important to note that all three options maximize contracted storage both by achieving firm storage injection in the summer and protecting maximum deliverability in the winter. EPCOR's learning and experience in executing gas procurement over the last three years are also considered when comparing these options. Generally all three options take the same approach to procurement and volume risk (by relying on the contracted storage and LBA) and focuses on managing price risk. All four options also aim to maximize storage utilization by leaving a small portion (~15%) of winter demand to be met by prompt, index, or spot purchases.

5.4. Summary Supply Option 1 (previously Option C)

Option 1 (previously Option C): This option consists of month to month purchases within 90 days prior to the start of the month, with procurement volume based on conservative average day demand forecast, taking into consideration storage withdrawal available during winter months, and injection requirements to fill storage during the summer months. Note that the purchasing window was increased from 7-14 days in the 2020 3-year Supply Plan, which risked transacting month to month fixed price contracts at higher prices during a rising price environment.

In October and November, the same purchasing strategy is used only there are no storage injections planned. For the December through March months, procurement volumes are made on a month-to-month basis to satisfy expected average day demand after considering storage withdrawal, with cash/spot purchases to fill the monthly demand shortfall and peak day demands not met by planned monthly storage withdrawals or drafting gas from the M17 LBA. Note that the purchasing window was increased from just November in the 2020 3-year Supply Plan, which risked transacting month to month fixed price contracts at higher prices during a rising price environment.

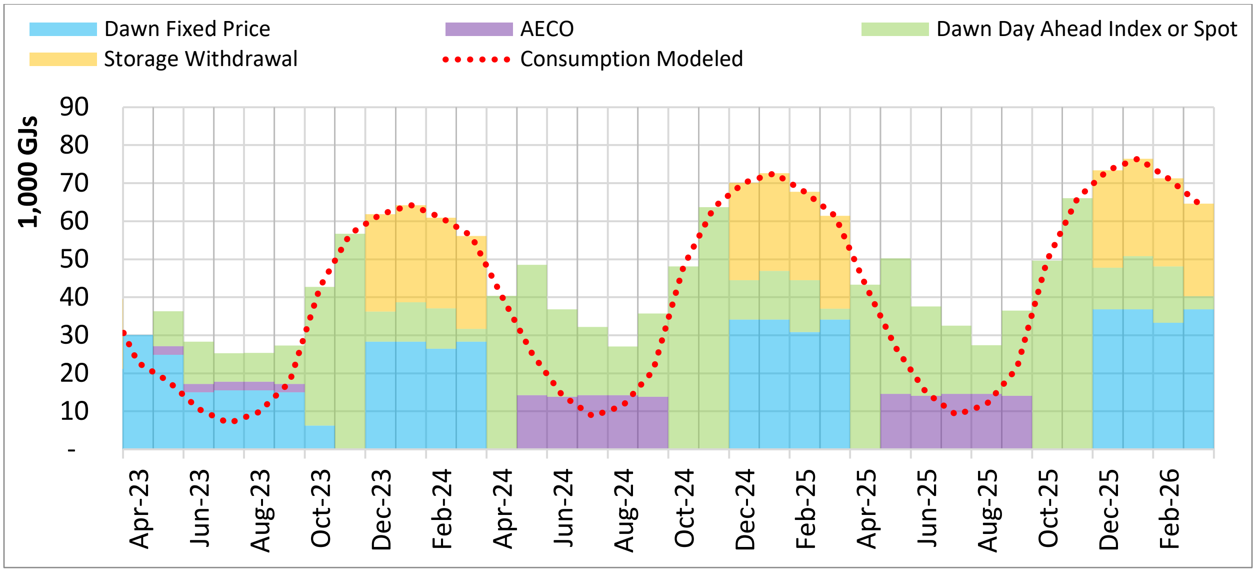
Planned procured volume for each month is the same as Option A, with up to 50% of each season's average consumption contracted prior to the start of the season at 5A Index plus a fixed basis to Dawn:

1) 50% of average consumption between May and September contracted in March or April at 5A Index plus a fixed basis to Dawn, and

2) 50% of average consumption between December to March priced using fixed priced at Dawn contracted in October or November each year.

Remaining monthly forecasted demand and peak day demand shortfall is met by planned monthly storage withdrawals, month-to-month purchases, and daily cash purchases.

Figure 7 – OPTION 1 (50% Seasonal Baseload Procurement @ 5A+ & Dawn Fixed) – Consumption vs. Delivery (GJ/Day)



Risks	Opportunities
Cost: Alberta market price dynamics may be different than Dawn leading to higher costs. Risk of fixed Dawn prices higher than index settles in the winter (low risk). Lower than forecasted winter demands in combination of low market prices may cause average weighted portfolio cost to be higher than market.	**Cost:** Cost risk reduced with a higher baseload quantity in the winter period. **Diversity:** Increased price diversity through setting of Fixed Basis in the summer. **Reliability:** Winter baseload quantity committed to in advance of winter months.

Option 1 incorporates price diversity into the portfolio by pricing indexing a subset of gas supply transactions at AECO 5A+. This arrangement also mitigates the price risk in a cost effective manner. This option may be less flexible as a certain level of procurement volume is committed ahead of time. However, this flexibility risk may be mitigated in that:

- There are two decision points through the planning year on setting these fixed volume term purchases, giving EPCOR more flexibility in adjusting these term volumes based on storage and LBA balance at the start of injection season, more up to date seasonal outlook, and customer connection forecast; and

- The flexibility in the contracted storage and the LBA to absorb the mismatch between forecasted and actual gas requirements for both winter and summer.

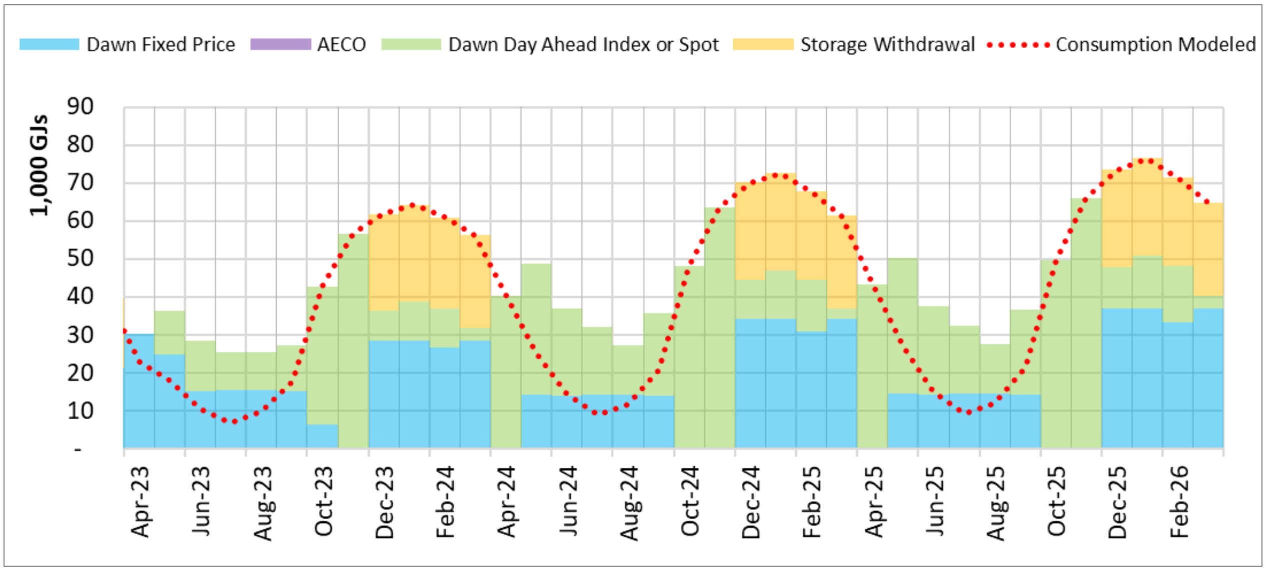
In the 2020 3-year Supply Plan, over-procurement was identified as a risk where EPCOR would need to sell the over-procured volume to remain within contracted parameters of storage and the LBA. EPCOR's experience over the last three years have shown that for this Supply Option, storage and the LBA combined are flexible enough to manage significant procurement and demand mismatches, even in the initial years of the plan where consumption was much lower than what was forecasted in the 2020 3-year Supply Plan (see Figure 2). In the past three years, EPCOR have successfully adjusted the procurement volumes through frequent and scheduled reviews and adjustments to the near-term demand forecasts by incorporating information from near term weather forecasts, actual customer additions to the system, actual storage and LBA balance, and adjusting long-term demand forecasts by adjusting assumptions on customer average customer consumption and rate of customer additions onto the system.

Option 1 provides additional price stability by procuring a portion of its winter supply at fixed price, which reduces the risk of spikes in index prices driving up EPCOR's WACOG. However, introduction of the 5A index in the summer also introduces price risk in the sense that weighted average cost of storage gas can become less predictable given that storage gas prices for the upcoming winter are driven by both AECO and Dawn market dynamics for the preceding injection season. One way EPCOR have mitigated price risk when transacting fixed priced contracts is through layering fixed price purchases over the procurement window – this provided additional flexibility in adjusting final procurement volumes to better match consumption as EPCOR has a better forecast of demand (more information) closer to the delivery date without having to commit to a single fixed price for the entire delivery volume within a narrow procurement window.

5.5. Summary Supply Option 2

Option 2: Same as Option 1, except 50% of average consumption between May and September contracted in March or April will also be fixed priced Dawn contract

Figure 8 – OPTION 2 (50% Seasonal Baseload Procurement @ Dawn Fixed) – Consumption vs. Delivery (GJ/Day)



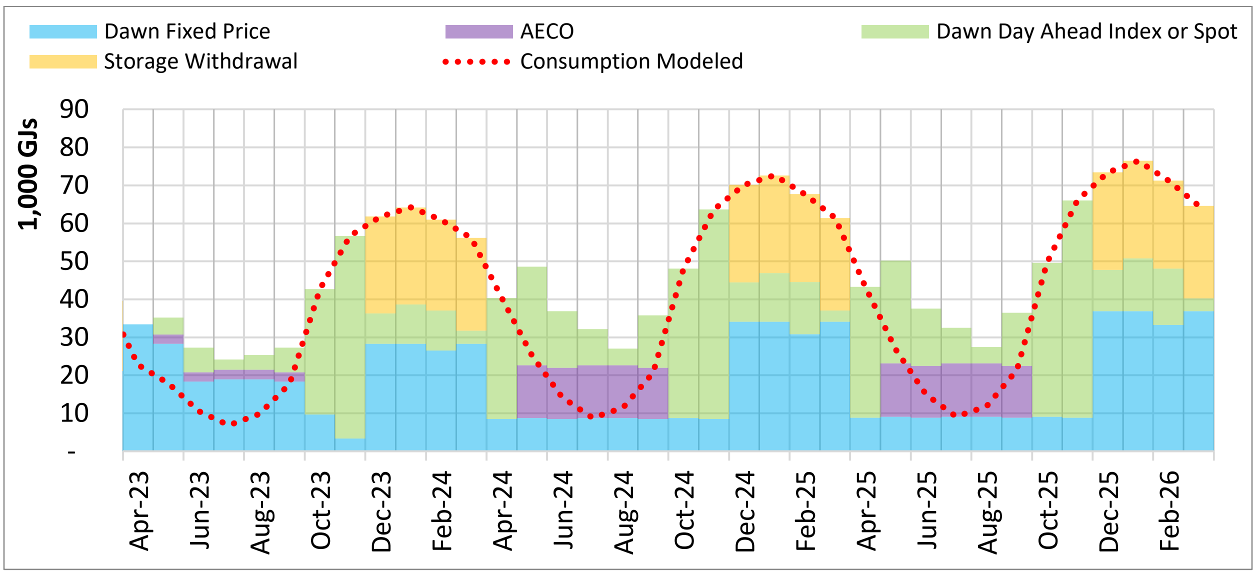
Risks	Opportunities
Cost: Risk of fixed Dawn prices higher than index settles in both summer and winter (low risk). Lower than forecasted winter demands in combination of low market prices may cause average weighted portfolio cost to be higher than market. **Diversity:** lower price diversity compared to other options	**Price stability:** higher predictability in weighted average cost of storage. **Cost:** Cost risk reduced with a higher baseload quantity in the winter period. **Reliability:** Winter baseload quantity committed to in advance of winter months.

Option 2 has a similar risk and opportunities profile compared to Option 1, however the price risks associated with AECO 5A+ basis is replaced with the risk of Dawn fixed prices higher than Dawn Day Ahead pricing.

5.6. Summary Supply Option 3

Option 3: Same as Option 1, with an annual fixed priced strip (April to March) at the lowest forecasted monthly consumption for the upcoming summer.

Figure 9 – OPTION 3 (Annual fixed price strip + up to 50% Seasonal Baseload Procurement @ 5A+ & Dawn Fixed)



Risks	Opportunities
Cost: Risk of fixed Dawn prices higher than index settles in both summer and winter (low risk). **Flexibility:** Less flexibility in managing risk of over-procurement in the summer (low risk).	**Price stability:** Annual strip creates more stable portfolio prices on an annual basis, especially for shoulder months. **Diversity:** Increased price diversity through setting of Fixed Basis in the summer.

	Cost: Cost risk reduced with a higher baseload quantity in the winter period. **Reliability:** Winter baseload quantity committed to in advance of winter months.

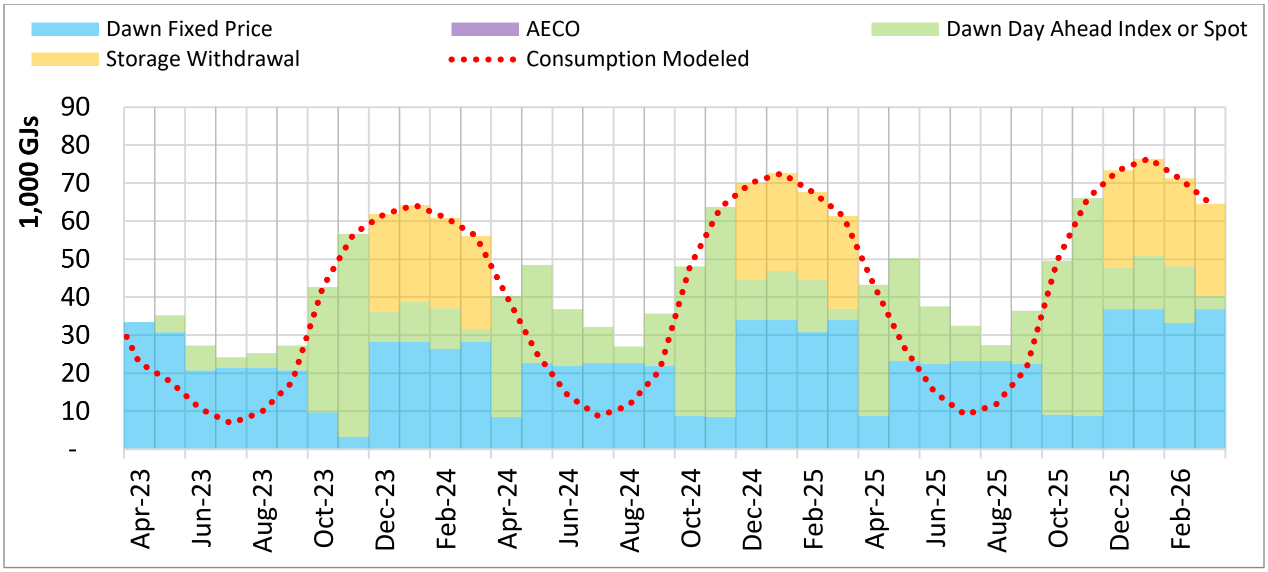
Option 3 has a similar risk and opportunities profile compared to Option 1, with slightly less flexibility in managing instance of low summer demand with the introduction of the fixed priced annual strip, while maintaining price diversity.

A risk highlighted with this Option is the reduced flexibility in adjusting gas procurement volume to changes in average day customer demand in situations where customer demand is lower than forecasted at the time of entering into the fixed priced annual contract. This situation would leave little flexibility to react to lower than expected customer demand in a lower consuming summer or after winters when storage balance remains high. This Option mitigates this risk by limiting the maximum amount of the annual strip to the minimum monthly volume forecasted for the upcoming summer. The annual strip also covers a small portion of the shoulder months in the fall, where system demand cannot be met by firm right withdrawal. The fixed contract provides some price stability during these two months when the portfolio have the highest exposure to market volatility.

5.7. Summary Supply Option 4

Option 4: Same as Option 3, however the summer AECO strip is replaced with seasonal fixed priced strip.

Figure 10 – OPTION 4 (Annual fixed price strip + up to 50% Seasonal Baseload Procurement @ Dawn Fixed)



Risks	Opportunities
Cost: Risk of fixed Dawn prices higher than index settles in both summer and winter (low risk). **Flexibility:** Less flexibility in managing risk of over-procurement in the summer (low risk).	**Price stability:** Annual strip creates more stable portfolio prices on an annual basis, especially for shoulder months. **Cost:** Cost risk reduced with a higher baseload quantity in the winter period. **Diversity:** Maintain price diversity through setting of Fixed Basis in the summer. **Reliability:** Winter baseload quantity committed to in advance of winter months.

Option 4 has a similar risk and opportunities profile compared to Option 3, with more stable commodity prices with the introduction of fixed Dawn price contracts rather than AECO.

5.8. Summary of Supply Options

The associated guiding principles to help evaluate a gas supply plan of Cost, Diversity, Reliability and Flexibility are used in Table 3. The cost risks/opportunities are evaluated quantitatively in the supply options analysis (Section 6) where each option is subjected to an endogenous shocks of demand and pricing impacts.

Table 3 - Supply Options Evaluation Summary

Supply Options	Reliability	Flexibility	Diversity	Price Stability
Option 1: 50% Summer AECO 5A+ baseload 50% Winter Dawn fixed baseload	↑	↑	↑	↓
Option 2: 50% Summer and Winter Dawn fixed baseload	↑	↑	–	↓
Option 3: Annual Dawn fixed baseload 50% Summer AECO 5A+ baseload 50% Winter Dawn fixed baseload	↑	↑	↑	–
Option 4: Annual Dawn fixed baseload 50% Summer & Winter Dawn fixed baseload	↑	↑	–	↑

6. Risk Mitigation Analysis

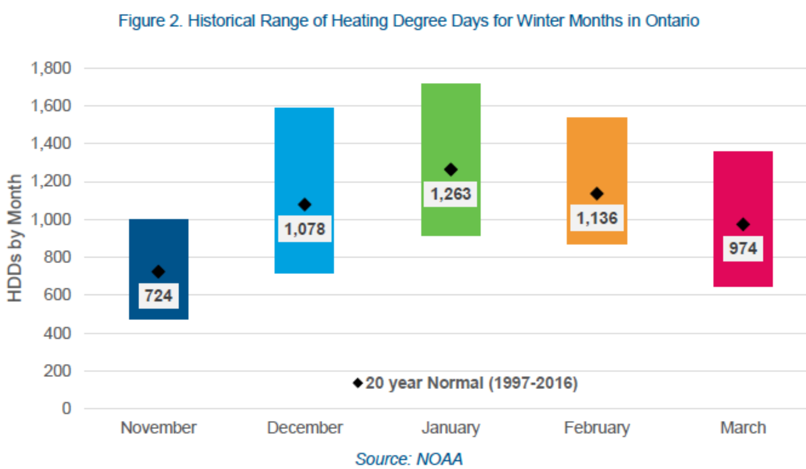
6.1. Variation to Planned Assumptions

Variation analysis to gas supply plan execution is the existence of risk mitigation strategies. Key risks to the Supply Plan are weather, demand (both average day and design day) and price variation.

6.1.1. Weather Variation Risk

The demand forecast presented in this Supply Plan assumes normal weather. Each supply option assumes a normal winter weather. The figure below comes from the 2019 Enbridge Gas Supply Plan as prepared by ICF. It shows historical ranges of Heating Degree Days (HDD) over a 20-year period (1997-2016) by winter month for all of Ontario. In tabular form, and by average for November to March, the low end 20-year average is 30% below and the high end is 38% above. The gas Supply Options were tested with weather variations of 30% less HDD and 38% more HDDs driving heat sensitive forecasted demand estimates.

Figure 11 – Ontario Heating Degree Day variation, 1997 to 2016



20 Years of data 1997-2016			
HDD - ONTARIO	Low	Mean	High
Nov	475	724	1,000
Dec	725	1,078	1,600
Jan	925	1,263	1,700
Feb	850	1,136	1,450
Mar	650	974	1,375
% from Mean	Low	Mean	High
Nov	34%	724	38%
Dec	33%	1,078	48%
Jan	27%	1,263	35%
Feb	25%	1,136	28%
Mar	33%	974	41%
	30%		38%

6.1.2. Demand Variation Risk – Average Day Demand

Demand Variation risk for EPCOR is largely due to its ability to forecast market growth measured by the number of new connections. Over the last three years, per-customer consumption average have been relatively consistent, especially for residential customers which make up the majority of customer connections. As such demand assumptions within each rate class are not tested in this analysis – per customer consumption variation is captured in the Weather Variation Risk instead (more / less HDD). Further, the customer forecast for this Supply Plan is also based on service applications EPCOR have received, and a conservative view of additional customer additions in 2024 and 2025. As shown in Figure 2, this forecast methodology used in the 2022 Supply Plan Update generated a realistic forecast compared to actual connections and system gas demand profile. In this 3-year Supply Plan, the greatest demand variation continue to be the frequency of new connections. The supply options were tested against 20% more and 20% less connections to the forecast. In all scenarios, LBA, adjustments to the use of storage, and prompt month / spot purchases were sufficient to meet deliverability.

6.1.3. Demand Variation Risk – Design Day Demand

Design day demand risk is a test of the highest component of demand. The combination of excess M17 transportation capacity, staged monthly storage deliverability, LBA parameters, month to month supplies and spot purchases at Dawn are more than adequate to comfortably satisfy design day demand within the planning horizon. No winter peaking services are planned in any of the supply options analysis.

6.1.4. Price Variation Risk

The price variation analysis shows potential cost outcomes on system gas customers in high and low price scenarios. One year of coincident prices at Dawn and AECO used to show realistic situations to test the supply options effects. For the high price scenario, Dawn index prices from April 2022 to December 2022 are used, as well as the prices from January to March of 2013 to simulate polar vortex prices. The prices chosen to present the low range period of April 2019 through March 2020 as it still presents the lowest Dawn (and NYMEX) winter price in the past several years.

6.1.5. Supply Interruption Risk

EPCOR has established a procurement policy which mandates contracting for supply from creditworthy suppliers and currently has three natural gas base contracts executed. At the start of its M17 contract with Enbridge, EPCOR elected to procure its supply from Dawn instead of Kirkwall or Parkway in its M17 supply contract with Enbridge as this is the most liquid of the supply points to choose form. All of these continue to form the basis for reducing the risk of supply interruption for this 3-year Supply Plan.

6.1.6. Transportation Interruption Risk

To minimize the transportation interruption risk, EPCOR has contracted for firm M17 upstream capacity to its franchise at Dornoch from a liquid supply point at Dawn. The amount of M17 capacity contracted was designed to serve its 10 years of forecasted growth for the winter peak. Higher residential connection counts relative to the CIP have meant the M17 capacity allocated to system gas customers is expected to be close to full utilization by January 2026. Higher than anticipated grain dryer peak day consumptions also means peak day consumption during grain drying season may also exceed the CD allocated to system gas customers by December 2024. EPCOR will continue to review this risk closely for the period covered in this 3-year Supply Plan, and have proactively reached out to Enbridge to explore options to service winter and grain drying peak days.

6.2. Cost of Supply Options

From a cost perspective, all three supply options track relatively close to each other. Appendix A summarizes the expected cost of servicing each of the three options from April 2023 to March 2026. The gas cost ranges from $6.66/GJ in Supply Option 1 to $4.11/GJ in Supply Option 3. The M17 Contract costs are based on the Contract Demand for General Service customers only (contract customers are excluded in the cost analysis since they are responsible for their own supply and storage).

Each of the Supply Options were shocked based on:

1) Warm, less connections: 30% less HDD and 20% less connections,
2) Cold, more connections: 38% more HDD and 20% more connection counts,
3) Low Price at planned demand volume (based on 2019/2020 Dawn and AECO index prices), and
4) High price at planned demand volume (based on a mix of 2022 and 2013/2014 Dawn and AECO index prices)

Table 4 – Summary of WACOG impacts of each modeled scenarios for each Supply Option

Supply Options	WACOG Impact for each Scenario against Base Scenario			
	Demand Shocks		Price Shocks	
	Warm, less connections	Cold, more connections	Low price at planned demand volume	High price at planned demand volume
Option 1	-2%	2%	-15%	41%
Option 2	-2%	2%	-11%	39%
Option 3	-2%	2%	-13%	33%
Option 4	-2%	2%	-9%	30%

As the table above shows, all supply options performed similar to each other in terms of managing demand shocks. With respect to protecting Southern Bruce's WACOG against price shocks, Option 4 performed the best due to the more stable prices with seasonal and annual fixed price contracts.

6.3. Summary of Chosen Supply Option

Given the results of the risk mitigation analysis, EPCOR is choosing the following Supply Plan 4. EPCOR will procure annual Baseload at Dawn based on the expected lowest month consumption for the planning year (April to March), Dawn fixed price contract up to 50% of summer demand (including storage injection requirements), and winter baseload at up to 50% of expected winter demand at Dawn fixed priced. The remaining monthly demand will be procured with month to month purchases at prompt fixed prices, Dawn Day Ahead index, or spot price purchases, taking into account injection requirements in the summer months and withdrawal deliverability in the winter months.

Option 4 was chosen for the planning horizon due to superior price risk management compared to the other three Options, especially in scenarios like the Winter 2013/2014 polar vortex where Dawn Day Ahead Index saw very severe price spikes, and sustained higher index pricing seen over 2022. Option 4 also allows for a good level of flexibility in the ability to adjust supply to actual demand – baseload volumes are relative to seasonal demand, meaning that they are low during low consumption months in the summer minimizing the risk of over contracting. Higher baseload in the winter time also have a lower risk of over contracting as storage withdrawals can be readily adjusted down if demand are lower than expected – for example, due to warmer than normal temperatures.

7. Gas Supply Plan Execution

EPCOR continues works with ECNG to carry out the Supply Plan as per the Board's guiding principles of cost-effectiveness and reliability of supply while remaining flexible to changes in actual customer demand. EPCOR and ECNG maintain a number of checks and balances throughout the execution phase of the supply plan to ensure adherence to the board's guiding principles, with a focus on mitigation of risks highlighted in Section 6.

There are no major changes to report since the last Supply Plan update, and no major changes are expected for the period covered in this 3-year Supply Plan.

7.1. Procurement Process/Policy

In Q1 of each calendar year, EPCOR's Energy Supply and Procurement Manager works with ECNG to develop a monthly procurement plan for the upcoming planning years (April to March). This plan outlines high-level guidance for natural gas procurement that allows for flexibility in addressing annual, seasonal, monthly and daily needs while maintaining a set of cost-effective supply and asset portfolio.

Within the year, the EPCOR's Energy Supply and Procurement Manager and the VP of Ontario directed and authorized ECNG to execute the approved Supply Plan. The Supply Plan is executed on a layered basis, with the annual Supply Plan providing high-level guidance for each planning year. Within the gas year, EPCOR will work with ECNG to assess and manage storage and transportation assets, and make adjustment to the procurement process on seasonal, monthly, daily basis supported by frequent and scheduled reviews of gas supply, storage and transportation asset utilization, and updates to customer demand profile.

Prior to the start of each planning year and each season, EPCOR will authorize ECNG to procure supply to meet forecasted demand and storage, at prices that reasonably track market conditions at the time of procurement. On a planned basis, EPCOR will direct ECNG to layer in purchases mainly through an RFP process (written and verbal), focusing on index price transactions that will track to market conditions at the time of delivery. EPCOR will also authorize fixed price transactions and term transactions (transactions of a specified volume with delivery period spanning more than a month) if it deems these transactions will contribute to price stability. ECNG have been given agency to transact on EPCOR’s behalf, and both EPCOR and ECNG are part of the transaction and invoice confirmation process.

Currently, EPCOR purchases gas under the Gas Electronic Data Interchange (“gasEDI”) contract with its papered suppliers with all gas delivered at the Dawn Hub. Supplier diversity will be assessed annually and determine how planned AECO index purchases have contributed to price stability. Other considerations when contracting for natural gas supply include: weather variance impact on its general service customers; difference between actual versus forecasted consumption of its general service customers; storage balance and deliverability from storage during various points of the year; LBA balance during various points of the year; fuel requirements and unaccounted for gas.

8. Historical Review

The following section provides a review of the 2020-2022 planning years, comparing the Plan for each year to the actuals experienced.

8.1. Heating Degree Days

The purpose of this section is to provide a brief review of the 2020 planning years, comparing the forecasted HDD underlying each gas supply plan to the actual HDD experienced.

Table 5 – Actual vs Plan Annual HDDs

	Heating Degree Days (HDDs)		
	Planned	Actual	Variance
2020/2021	3,831	3,741	90
2021/2022	3,831	3,709	122
2022/2023	3,831	3,538	293

- 2020/2021 – HDDs were lower than planned due to warmer than expected temperatures
- 2021/2022 – While HDDs were initially higher in January 2022, results were lower than planned due to warmer than expected temperatures in February and shoulder months
- 2022/2023 – HDDs were much lower than planned due to warmer than expected temperatures, especially in January and February 2023

8.2. Annual Demand

The purpose of this section is to provide a brief review of the 2020-23 planning years, comparing the demand forecast underlying each gas supply plan to the actual throughput volume. Actual volumes have not been normalized for weather variances.

Table 6 – Actual vs Plan Annual Demand

	Annual Demand (TJ)		
	Planned	Actual	Variance
2020/2021	138	15	123
2021/2022	272	120	152
2022/2023	540	248	292

- 2020/2021 – Delay in construction and slower than forecasted pace of conversion lead to lower than forecasted demand

- 2021/2022 – Southern Bruce continued to see delay in HVAC conversion. In addition, actual per residential customer demand was also lower than what was modeled in the original CIP, which was the basis for the 2020 Gas Supply Plan and the 2021 Gas Supply Plan Update.

- 2022/2023 –Actual per residential customer demand continue to be lower than what was modeled in the original CIP, which was the basis for the 2020 Gas Supply Plan and the 2021 Gas Supply Plan Update.

8.3. Commodity Portfolio

The purpose of this section is to provide a brief review of the prior three years, comparing the supply forecast underlying each gas supply plan to the actual supply procured.

Table 7 - Actual vs Plan Commodity Purchases

		Commodity Purchases (GJ)		
		Planned	Actual	Variance
2020/2021	Dawn	138	102	36
	AECO	0	0	0
2021/2022	Dawn	272	66	206
	AECO	0	0	0
2022/2023	Dawn	540	249	291
	AECO	0	0	0

- 2020/2021 – Delay in construction and slower than forecasted pace of conversion lead to lower than forecasted gas supply deliveries

- 2021/2022 – in the previous gas year (ending March 31, 2021), a high volume of gas remained in storage as discussed in the last Gas Supply Plan update. Coupled with very low consumption in the Summer of 2021, most of the gas procured over the summer was to fill storage. Consumption in winter of 2021 / 2022 was also lower than anticipated, leading to most of the demand being met by storage withdrawal.

- 2022/23 – in the planning year ending March 31, 2023, almost all system gas demand were met by market purchases made in that year.

8.4. Unutilized Transportation Capacity

The purpose of this section is to provide a brief review of the prior three years, comparing the Unutilized Transportation Capacity underlying each gas supply plan to the actual Unutilized Transportation Capacity incurred.

Table 8 - Actual vs Plan UDC

	Unutilized M17 Capacity (GJ)		
	Planned	Actual	Variance
2020/2021	4,308	4,941	633
2021/2022	3,874	4,021	147
2022/2023	2,284	2,543	259

- 2020/2021 – The actual Unutilized M17 Capacity incurred was 633 GJ lower than planned primarily due to delay in construction and slower than forecasted pace of conversion
- 2021/2022 – The actual Unutilized M17 Capacity was 147 GJ lower than planned primarily due to slower than forecasted pace of conversion, as well as lower than anticipated average residential customer consumption.
- 2022/2023 – The actual Unutilized M17 Capacity was 259 GJ lower than planned primarily due to slower than forecasted pace of conversion, as well as lower than anticipated average residential customer consumption.

9. Public Policy

9.1. Community Expansion

EPCOR has been actively working to bring secure, reliable and affordable natural gas to unserved communities. The Southern Bruce project represents one of the largest community expansion projects awarded to date. EPCOR will continue to work to expand access to natural gas service to communities who are not currently connected to a natural gas distribution, and pursuant to EPCOR's obligation to serve, to any customers or communities who request natural gas service. EPCOR continues to assess expansion opportunities in the area, and as noted in Section 3 above, has received conditional CPCN approval for the area of Brockton and is currently developing a leave to construct application for approval to commence construction.

EPCOR is also monitoring community expansion plans and energy management plans of communities within the Southern Bruce franchise area. Specifically, EPCOR reviewed the following plans as part of this Supply Plan:

- Municipality of Kincardine Energy Conservation and Demand Management Plan: 2019-2024[6]
- Township of Huron-Kinloss – Climate Change and Energy Plan (2020)[7]
- The Corporation of the Municipality of Arran-Elderslie Conservation and Demand Management Plan: 2019-2024[8]
- Plan the Bruce: Bruce County Official Plan[9]

EPCOR did not find significant updates during this year's review that will impact EPCOR Southern Bruce's gas demand forecast. EPCOR expects communities will update their Conservation and Demand Management Plans and community growth plans in the next two years.

---

6 https://www.kincardine.ca/en/municipal-office/resources/Documents/Kincardine-ECDMP-2019-2024-Final-Draft.pdf
7 https://www.huronkinloss.com/en/townhall/resources/Documents/Huron-Kinloss-Climate-Change-and-Energy-Plan_REVISED-December-2020.pdf
8 https://www.arran-elderslie.ca/en/municipal-services/resources/Documents/Conservation-and-Demand-Management-Plan-2019-2024.pdf
9 https://www.planthebruce.ca/official-plan

9.2. Minister of Energy Letter of Direction

On October 21, 2022, Todd Smith, Minister of Energy, provided a letter of direction of Richard Dicerni, 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:

- Supporting the Electrification and Energy Transition Panel
- Regulatory Framework
- Distribution Sector Resiliency, Responsiveness and Cost Efficiency
- Electric Vehicles
- Strengthen the Performance Measurement Framework
- Red Tape Reduction

The letter also addressed other priorities including Conservation and Demand Management/Demand-Side Management (CDM/DSM). The letter stated: "*I am looking to the OEB to ensure Ontario natural gas ratepayer interests are protected and that Ontario takes every opportunity to generate deeper retrofits, more natural gas savings and greater emissions reductions".*

EPCOR will continue to support the Minister's priorities and monitor the impacts on the Supply Plan, including plans for DSM/retrofit rollout and collaboration as noted further in this section (Section 9.4). There are no direct impacts from the Minister's letter on this filing.

9.3. 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-2022-0245. EPCOR will continue to monitor and assess the potential impact of the FCPP on future customer consumption and conversion decisions.

9.4. Demand Side Management (DSM)

As per Broad Staff's recommendation in their Review of the 2022 Annual Update, EPCOR 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.

9.5. 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.

At this time, EPCOR does not hold any RNG supply in its Southern Bruce Supply Plan. EPCOR will update the Supply Plan as strategies for an RNG solution are developed and finalized in the Southern Bruce service territory. There are no updates to any RNG-related opportunities for EPCOR Southern Bruce at this time.

9.6. Integrated Resource Planning

As discussed in Section 3.1.3, this 3-year Supply Plan does not include potential impacts of future IRP projects. As per the OEB Staff Report for the Review of the 2022 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 Southern Bruce for the period covered by this Supply Plan.

9.7. Canada Green Homes Grant

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.

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

10.Performance Measurement

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-2022-0141, OEB staff recommends that EPCOR provide details regarding its consideration of scorecard improvements (including potentially adding targets) at the time of its next three-year Supply Plan for the Southern Bruce service area. In Pollution Probe's Comments to the 2022 Annual Gas Supply Plan Update, Pollution Probe suggested EPCOR considered adding target results for the performance metrics included in Appendix F. However, since the performance metrics are mostly comprised of compliance requirements or operational metrics that are not conducive to setting a specific target, EPCOR has not included target results in the scorecard. In reference to Enbridge's Gas Supply Plan Scorecard, EPCOR found that the three-year average added to Enbridge's scorecard in their 2022 update served as a good metric to compare year-on-year variances for the duration of the supply plan – as such EPCOR have included the 3-year average in the Scorecard starting with this 3-year Supply Plan.

11. 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.

12.Link to Other Applications

Related Application	How the Gas Supply Plan (Plan) informs the related applications	How the related application informs the Plan	Rate implications
Quarterly Rate Adjustment Mechanism	Will result in ongoing changes to the pass-through gas supply cost which are generally recovered through QRAM applications	QRAM applications include data and information which will help to inform Annual Updates and the next five year Plan	Mechanism through which most commodity and gas supply costs are passed through to customers in rates
Cost of service application for the rate stability period (2019-2028) (EB-2018-0264)	May inform mid-term updates and evidence when seeking specific deferral and variance account clearances, and service offerings, e.g. direct purchase option	The approved cost of service application set the assumptions underpinning the system configuration, customer connections, and volume forecast for the 2020 update to the Plan.	Rate schedules across rate classes defined by this filing, which include some limited gas supply charges and terms and conditions for rates.
Annual Rate Applications	Limited impact until end of rate stability term. On incentive rates formula until end of 2028 calendar year.	Not expected to influence the plan	Some gas Supply cost charges are updated pursuant to the incentive rates adjustment formula, and costs passed through to customers through Annual rate applications.
Leave to Construct Applications	The Plan provides the foundation for related Leave to Construct applications. Helps to align execution of these LTCs in accordance with the OEB's guiding principles in the EB-2017-0129 Framework.	New gas supply options, if any, resulting from new LTCs to be reflected by the Annual Update and the next iteration of the five year plan.	Any resulting changes to gas supply costs will be reflected in QRAM and/or Annual Rate applications.

Potential Projects to Expand Access to Natural Gas Distribution re: 2019 *Minister's Directive*	Projects are evaluated within the context of the framework set by the Board. Plan informs only the cost of gas supply generally speaking for bill impact and conversion analysis for bids.	Annual updates to the Plan to reflect new customer additions and any new incremental supply from existing supply points, as well as any diversity and flexibility provided by new potential points of supply and new/other suppliers as applicable.	By nature, any projects connected would be with funding which brings the P.I. to 1.0, therefore no material changes to rates, and harmonized into the existing service area and rates.
Long-Term Contract Applications	The Plan does not give rise to Long-Term Contracts, and therefore Long-Term Contract Applications are not foreseen.	EPCOR has no plans to enter into Long-Term Contracts as part of the Plan. There are limited fixed-price contracts for periods less than 12 months.	Material changes to gas supply costs resulting from Long-Term Contract applications will be reflected in QRAM and/or Annual Rate applications.

13. Appendices

Appendix A – Scenario Analysis Results for Supply Plan Options 1 to 4

Table 9 – Supply Option 1 Scenario Analysis: April 2023 to March 2026

	Option 1 Base Scenario	Option 1 Warm, less connections	Option 1 Cold, more connections	Option 1 Low price at planned demand	Option 1 High price at planned demand
Commodity Cost (Baseload)	$3,209,049	$1,813,666	$5,223,939	$2,882,112	$3,428,020
Commodity Cost (Month to Month)	$3,479,008	$2,336,609	$5,078,862	$2,547,428	$6,626,901
Commodity Cost (Spot Gas)	$0	$0	$0	$0	$0
Storage Costs (inc. storage fuel)	$271,536	$271,705	$271,476	$268,903	$279,354
M17 Transportation Charges	$994,728	$973,936	$1,024,217	$994,728	$994,728
M17 Transportation Fuel Cost	$53,750	$35,429	$80,274	$46,542	$74,512
M17 LBA Charges	$0	$0	$0	$0	$0
Management Cost	$246,414	$225,623	$275,904	$246,414	$246,414
Total Cost	**$8,254,486**	**$5,656,967**	**$11,954,672**	**$6,986,127**	**$11,649,930**
$ per GJ of Demand	$4.72	$4.60	$4.81	$4.00	$6.66
¢ per m3 of Demand	18.49	18.04	18.84	15.65	26.10

Table 10 – Supply Option 2 Scenario Analysis: April 2023 to March 2026

	Option 2 Base Scenario	Option 2 Warm, less connections	Option 2 Cold, more connections	Option 2 Low price at planned demand	Option 2 High price at planned demand
Commodity Cost (Baseload)	$3,169,707	$1,779,174	$5,663,906	$3,169,707	$3,169,707
Commodity Cost (Month to Month)	$3,518,413	$2,371,156	$5,583,807	$2,580,108	$6,730,300
Commodity Cost (Spot Gas)	$0	$0	$0	$0	$0
Storage Costs (inc. storage fuel)	$271,540	$271,708	$271,468	$269,978	$278,838
M17 Transportation Charges	$994,728	$973,936	$1,032,037	$994,728	$994,728
M17 Transportation Fuel Cost	$53,750	$35,429	$86,998	$47,659	$73,972
M17 LBA Charges	$0	$0	$0	$0	$0
Management Cost	$246,414	$225,623	$283,723	$246,414	$246,414
Total Cost	**$8,254,553**	**$5,657,026**	**$12,921,939**	**$7,308,594**	**$11,493,960**
$ per GJ of Demand	$4.72	$4.60	$4.82	$4.18	$6.57
¢ per m3 of Demand	18.49	18.04	18.88	16.37	25.75

Table 11 – Supply Option 3 Scenario Analysis: April 2023 to March 2026

	Option 3 Base Scenario	Option 3 Warm, less connections	Option 3 Cold, more connections	Option 3 Low price at planned demand	Option 3 High price at planned demand
Commodity Cost (Baseload)	$3,897,706	$2,382,891	$6,039,815	$3,578,228	$4,112,490
Commodity Cost (Month to Month)	$2,790,407	$1,774,138	$4,262,993	$2,048,684	$5,239,785
Commodity Cost (Spot Gas)	$0	$0	$0	$0	$0
Storage Costs (inc. storage fuel)	$271,485	$271,360	$271,514	$269,290	$277,452
M17 Transportation Charges	$994,729	$973,938	$1,024,218	$994,729	$994,729
M17 Transportation Fuel Cost	$53,106	$34,511	$79,682	$46,717	$71,237
M17 LBA Charges	$0	$0	$0	$0	$0
Management Cost	$246,415	$225,624	$275,904	$246,415	$246,415
Total Cost	**$8,253,849**	**$5,662,461**	**$11,954,125**	**$7,184,063**	**$10,942,109**
$ per GJ of Demand	$4.72	$4.61	$4.81	$4.11	$6.26
¢ per m3 of Demand	18.49	18.05	18.84	16.10	24.51

Table 12 – Supply Option 4 Scenario Analysis: April 2023 to March 2026

	Option 4 Base Scenario	Option 4 Warm, less connections	Option 4 Cold, more connections	Option 4 Low price at planned demand	Option 4 High price at planned demand
Commodity Cost (Baseload)	$3,897,765	$2,382,944	$6,039,884	$3,897,765	$3,897,765
Commodity Cost (Month to Month)	$2,790,407	$1,774,138	$4,262,993	$2,048,684	$5,239,785
Commodity Cost (Spot Gas)	$0	$0	$0	$0	$0
Storage Costs (inc. storage fuel)	$271,489	$271,363	$271,517	$270,362	$276,734
M17 Transportation Charges	$994,729	$973,938	$1,024,218	$994,729	$994,729
M17 Transportation Fuel Cost	$53,107	$34,511	$79,682	$47,831	$70,488
M17 LBA Charges	$0	$0	$0	$0	$0
Management Cost	$246,415	$225,624	$275,904	$246,415	$246,415
Total Cost	$8,253,911	$5,662,517	$11,954,197	$7,505,787	$10,725,916
$ per GJ of Demand	$4.72	$4.61	$4.81	$4.29	$6.13
¢ per m3 of Demand	18.49	18.05	18.84	16.82	24.03

Appendix B – Key Terms

AECO 5A Index: Popular index pricing instrument for the Alberta AECO Hub. Arithmetic average of daily prices, which are weighted average settlement prices for same-day delivery at AB-NIT. Tracks Alberta market prices closely.

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

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

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.

Dawn Day Ahead Index: Popular index pricing instrument for the Ontario Dawn hub. Arithmetic average of daily prices, which are weighted average settlement prices for next-day delivery at Dawn. Tracks Ontario market prices closely.

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 Days (HDD): 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.

Planning Year: A period of twelve (12) consecutive months usually beginning on April 1st and continuing until March 31st of the following year.

Rate 1 – General Firm Service Rate: Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose total gas requirements are equal to or less than 10,000 m3 per year.

Rate 6 – Large Volume General Firm Service Rate: Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose total gas requirements are greater than 10,000 m3 per year.

Rate 11 – Large Volume Seasonal Service: Any customer connected directly to EPCOR's Southern Bruce Natural Gas High Pressure Steel System and who enters into a contract with EPCOR for firm contract daily demand of at least 2,739m3.

Rate 16 – Contract Firm Service Rate: Any customer connected directly to EPCOR's Southern Bruce Natural Gas High Pressure Steel System and who enters into a contract with EPCOR for firm contract daily demand of at least 2,739m3.

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 C – Market Trends Analysis

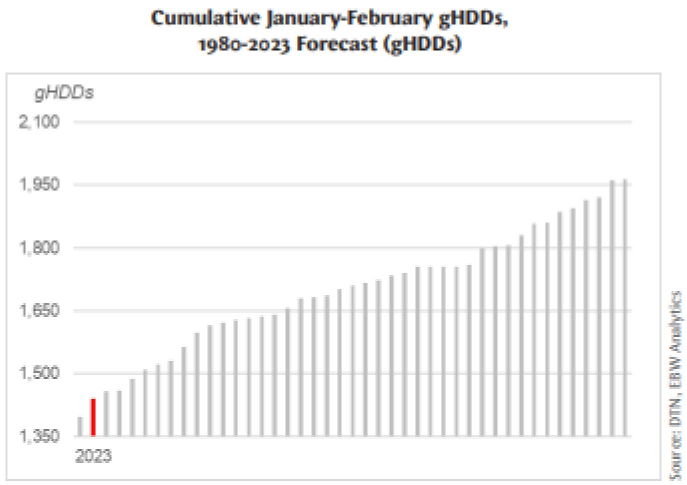
Current and Future Market Trends Analysis
Provided by ECNG

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. “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.

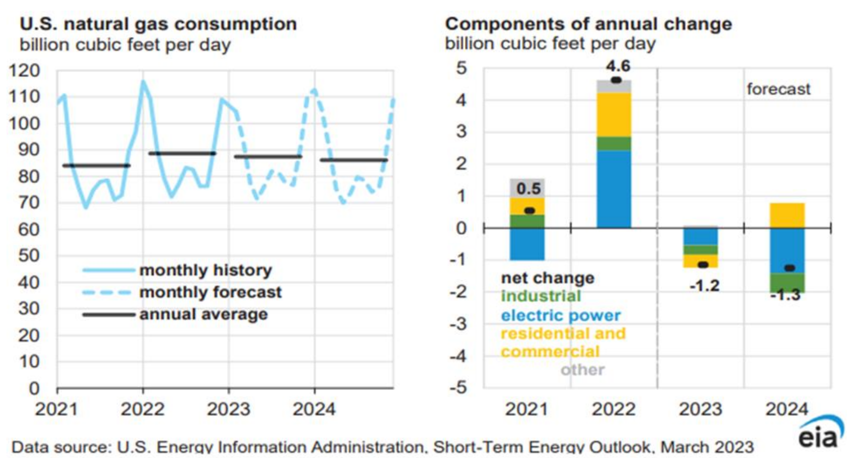
Continuing in this outlook is the war in Ukraine and global free-world unification regarding economic sanctions against the Russian economy and oligarchs. The phase out European imports of Russian oil, natural gas, coal, and steel initially resulted in a surge in prices of these and related commodities alternatively sourced around the globe. The prices of these and related commodities have stabilized and pulled back largely due to warm winter weather in both Europe and N.A. in early 2023.

Demand: Impact on pricing – Near-term Mildly Bullish (NYMEX) and Bearish (AECO); Mid and Long-term Bullish (NYMEX) and Bullish (AECO)

US natural gas R&C sector consumption in 2022 continued to rebound from pandemic lows of 2020. The EIA forecasts a modest drop in R&C demand for 2023 largely influenced by the start of 2023 with January and February combined marking the second warmest since 1980 resulting in 7.9 Bcf/d below 10-year normal demand.

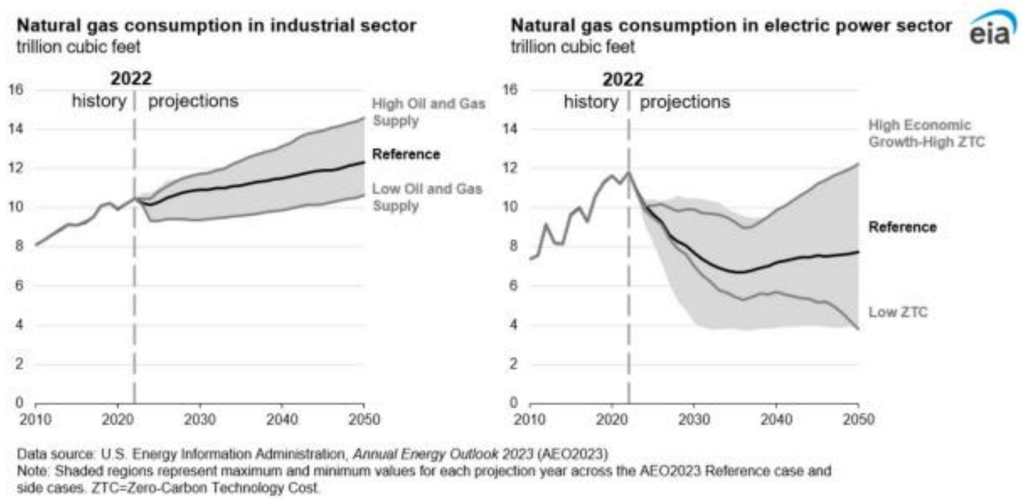


Industrial demand, however, appears to have grown by 1-2 Bcf/d from pandemic lows however have flattened in the forecast in EIA's most recent Short Term Energy Outlook 2023 - April 2023 (STEO 2023).

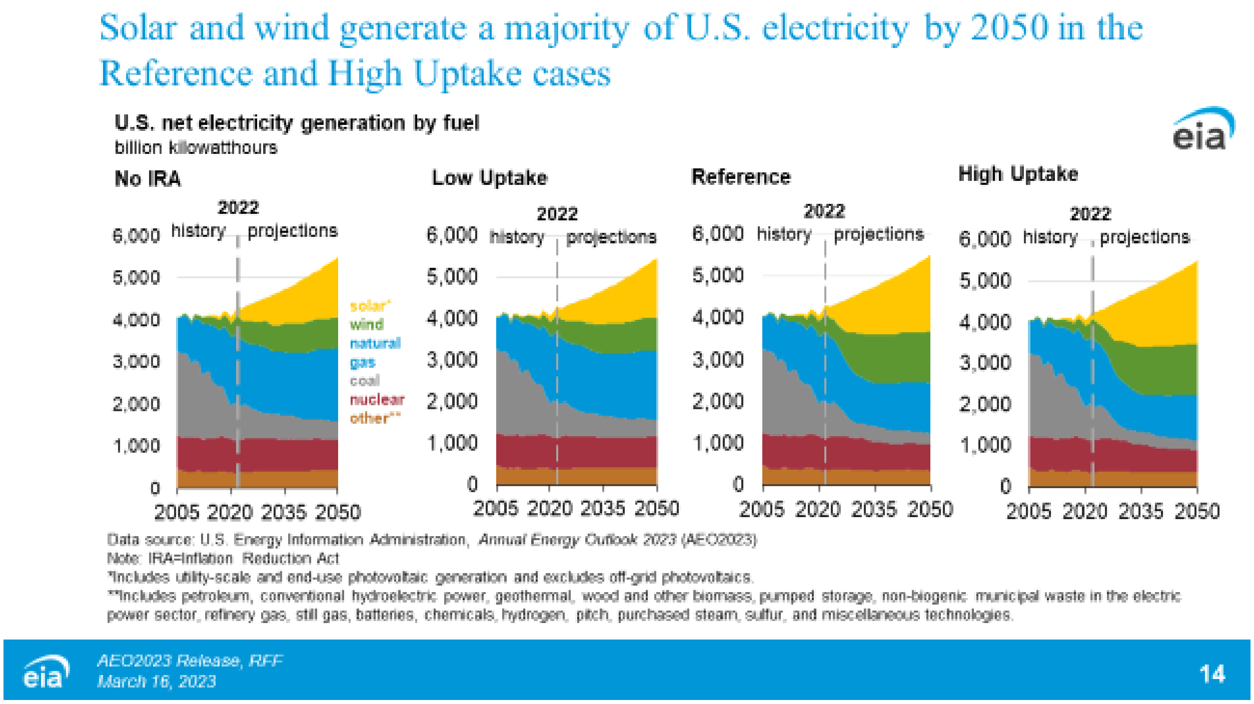


Mid-term and Long-term gas demand growth is largely expected by most forecasters in the United States (U.S.) in industrial and gas fired power generation demand sectors. At the time of this writing, near term N.A gas pricing is approximately $4 US/MMBtu higher than last year. Coal-fired power generation retirements 11 Gigawatts (GW) in 2023 continue in favour of gas-fired generation. Also, gas fired generation will likely continue running more baseload hours not only due to attrition of the coal fired fleet but due to the dramatic drop in gas pricing making it cheaper than coal. Growth in gas-fired power generation is expected to be offset by the increase in solar capacity of 27 GW in 2023, up 38% from last year. Solar and wind generation of a combined 77 GW is expected to be installed from Dec 2022 to the end of 2024 as forecasted in STEO 2023. In the industrial sector significant divergence is shown in the High and Low Oil and Gas Supply cases in the EIA forecasts. It is difficult to surmise such a divergence in just a few years out from 2022 as industry consumption of natural gas is not so elastic as to be able to fuel switch other than the petroleum refinery sector. 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 and/or LNG feedgas for exports discussed later.

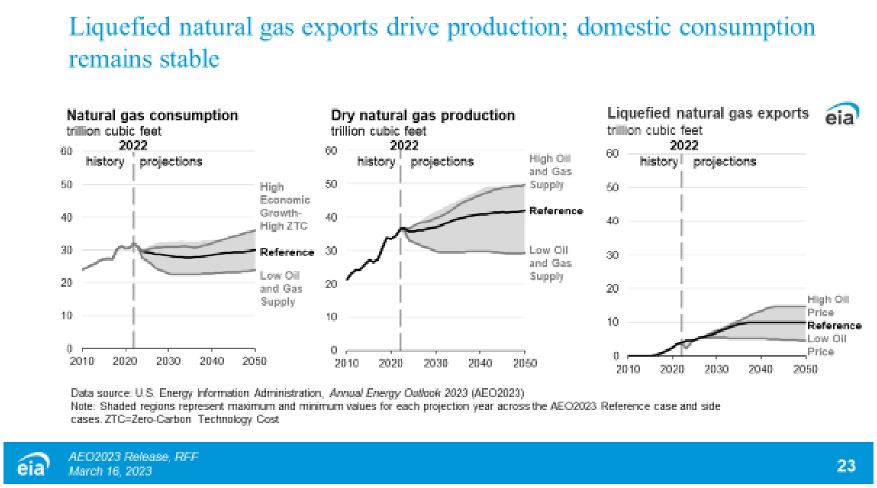
Figure 15.



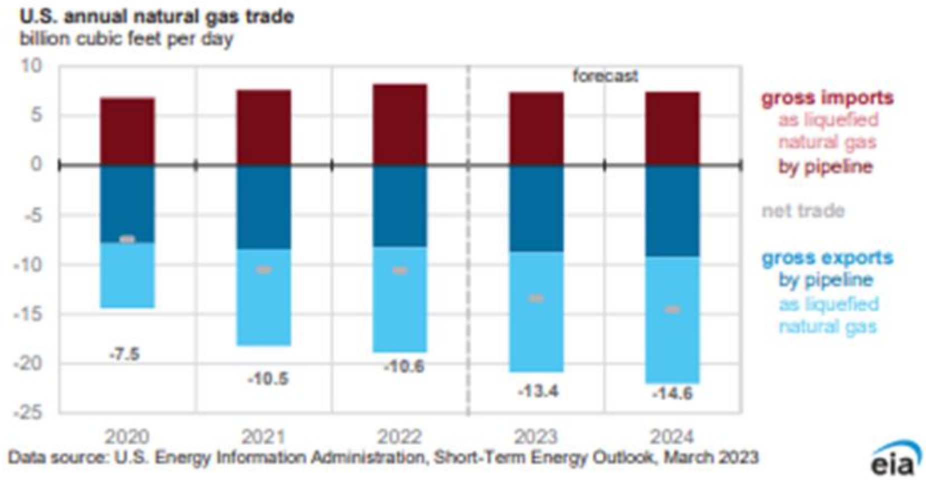
The EIA in its latest Annual Energy Outlook (AEO2023) cites in its Reference Case a modest drop of natural gas for power generation to the end of 2030 at the expense of renewables. In its High Uptake Case (high uptake of renewables driven by federal government funding Inflation Reduction Act) natural gas consumption drops more significantly at the expense of renewables. The graphs below show these forecasted trends. In ECNG's view 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. Each of the scenarios in the rightmost graphic below identifies that by 2025 approximately 7,500 Tcf/yr (20.5 Bcf/d on average) is expected based on regulatory approved projects. This is an increase of nearly 10 Bcf/d from 2022 average of 10.7 Bcf/d.



U.S. LNG exports including fuel gas for refrigeration are now operating near capacity between 14 and 15 Bcf/day in early in Q2 2023 (except for planned maintenance or unexpected outages). EIA estimates on average 13.4 Bcf/d will be exported in 2023 (not including fuel which is approximately 10%) which is realistic if high load factors can be maintained continue to be the most significant contributor to a tight supply-demand balance in N.A. Imports and exports to/from Canada and Mexico are not expected to grow or fall materially in the near-term time horizon as pipelines are operating at near capacity.



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. There are another 3 LNG export projects that have not yet reached FID (Final Investment Decision) which will require supply via U.S. pipeline also likely from the Permian basin which would increase US exports to Mexico post 2025.

There are also LNG export projects to the Canadian Pacific Coast for Western Canadian Sedimentary Basin (WCSB) supply that continue to be delayed and with much higher costs. LNG Canada's 0.9 Bcf/d project is now expected to flow in 2026 (delayed from 2024) and Cedar LNG's 0.4 Bcf/d project is now expected to flow in 2028-29 (delayed from 2027). Only Woodfibre 0.3 Bcf/d, expected to flow in 2027 has not changed its start date. The Ksi Lisims LNG project, 2 Bcf/d has emerged on West Coast targeting flow by 2028-2029 as is LNG Canada's 1.8 Bcf/d Train 2. 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. Very little oil sands production growth is forecasted, and the coal fired generation retirements will be complete at the end of 2023 with only 0.3 Bcf/d increase in average gas consumption expected as a result.

The US demand outlook for 2023 and beyond is for modest to no growth in domestic demand from R&C, 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 – Near-term Bullish (NYMEX) and Bearish (AECO); Mid and Long-term Very Bullish (NYMEX) and Mildly Bearish (AECO)

U.S. dry gas production (supply) growth has been impressive since Q4 2022 and so far in Q1 2023 driven by high prices in 2022 and eventual reinvestment by producers. US producer sentiment continues to show supply growth driven by disciplined sustainable expansion balancing producer financial health (paying down debt) and shareholder value (dividends). The issues of early to mid-2022 labour shortages, higher labour and raw material costs and a global shortage of drilling rigs seems to have subsided. The free world has been fortuitous with warm winter weather in Europe and the US coincident with lower energy demand from China (due to COVID resurgence) increasing inventories and dropping fuel prices. Although production to date in 2023 appears to be nearly 2.5 Bcf/d higher YoY the question is whether it is sustainable at current and near term forward natural gas prices of approximately $3.00 US/MMBtu. The EIA is forecasting for 2023 101 Bcf/d an increase of 3% over 2022. At this point in time that forecast appears realistic.

UNITED STATES Supply & Demand	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023 YTD	Y / Y
Dry Production	57.3	61.8	64.7	65.4	70.0	73.2	71.8	74.1	83.6	92.2	90.6	93.6	97.6	100.4	2.9%
Canadian Imports	6.5	5.6	5.1	5.0	5.1	5.3	5.7	5.4	5.3	4.6	4.3	5.0	5.6	5.1	
LNG Imports	1.1	0.7	0.5	0.3	0.1	0.2	0.3	0.2	0.2	0.2	0.1	0.1	0.2	0.2	
Total Supply	**64.9**	**68.1**	**70.3**	**70.7**	**75.2**	**78.7**	**77.8**	**79.7**	**89.1**	**97.0**	**95.0**	**98.7**	**103.4**	**105.7**	
Power Burn	20.2	20.8	24.6	22.6	22.7	26.4	27.1	25.5	28.9	30.9	31.7	31.0	33.3	30.1	-9.6%
Industrial	18.9	19.2	19.7	20.3	20.9	20.6	21.2	21.8	22.8	23.0	22.4	22.8	23.1	24.3	
Res/Comm	22.7	22.3	20.3	23.8	24.7	22.8	21.5	21.4	23.2	23.5	21.5	21.9	23.0	35.2	
Mexican Exports	0.8	1.3	1.7	1.8	2.0	2.9	3.7	4.3	4.6	5.1	5.4	6.0	5.8	5.6	
LNG Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.6	2.2	3.4	5.7	7.3	10.7	11.8	12.9	9.3%
Pipe Loss	4.7	4.8	5.1	5.6	5.4	5.5	5.4	5.6	6.2	7.0	6.9	7.4	7.8	8.0	
Total Demand	**67.3**	**68.5**	**71.5**	**74.2**	**75.7**	**78.1**	**79.5**	**80.8**	**89.2**	**95.2**	**95.1**	**99.9**	**104.8**	**116.1**	

Updated April 1, 2023 All figures in BCF per day

Strong Growth Flat Growth

Source: Platts; Recalibrated by Platts March 27, 2023

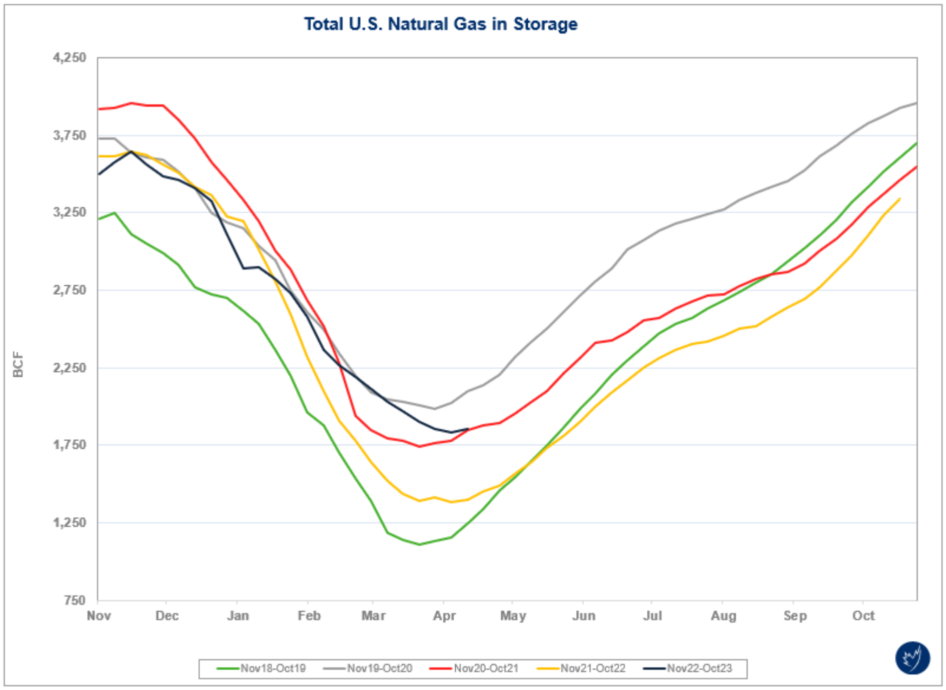
Note: 2023 is only Year to date so some numbers are not relevent.

The Western Canadian Sedimentary Basin (WCSB) production has grown substantially in response to the confluence of higher AECO pricing, higher oil sands and Alberta power generation demand (continued phase out of coal fired generation) and increased access to domestic and export markets through significant NGTL (Nova Gas Transmission) expansion nearing full completion. The NGTL facilities expansion continues in 2023 supporting drilling activity in Alberta resulting in growth of supply exceeding 18.5 Bcf/d consistently in April 2022. British Columbia production has also grown as well despite new BC licenses being issued as of A new resolution framework for resource development was announced January 26, 2023 between the BC provincial government and the Blueberry River First Nation enabling new licenses to be issued. Subsequently in the days following, four other Treaty 8 Nations signed similar agreements. We are optimistic that a growth in BC supply will resume in the prolific Montney formation in 2023.

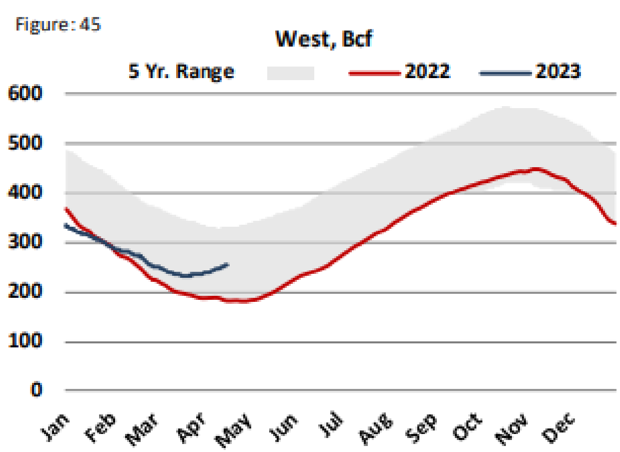
The supply response in the WCSB will be quicker on a percentage basis compared to the U.S. however additional supply will be suppressed by limited pipeline capacity to the US and Eastern Canada to impact the NYMEX / US market. These constraints along with healthy storage levels and only modestly growing BC and AB demand are driving the bearish sentiment in the short run. Mid and Long-term the sentiment moves towards bullish as LNG Canada begins circa 2026.

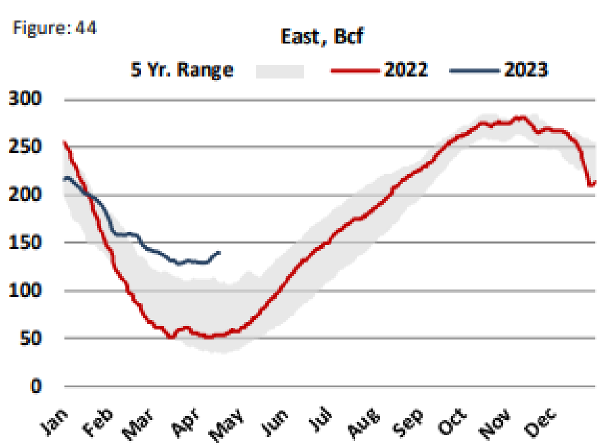
Storage: Impact on pricing – Near term Very Bearish (NYMEX and Dawn), Bearish (AECO); Mid and Longer-term No Impact on price

Total U.S. working inventories on March 31, 2023 ended well above the five-year average of 1.53 Tcf by approximately 300 Bcf (surplus). Most industry forecasters see the end of the 2023 injection season ending in a surplus to the five-year average but only between 1-200 Bcf, mostly due to increased LNG exports and waning supply growth (due to surprisingly low gas prices). The likely outcome is that storage filling about 100-150 Bcf more than last year or about 1 Bcf/d more supply available in the upcoming winter. Unless supply levels continue to grow to meet rebounding LNG exports and growing gas fired power generation this may lead to an inventory level at the end of the upcoming winter season significantly less than the 5-year average. US storage graph using EIA weekly data up to April 7, 2023.



In Canada, storage at winter's end in Alberta (essentially the "West" graph below) has dramatically recovered and is now near the 5-year average, whereas storage at Dawn (essentially the "East" graph below) is above the 5-year high.



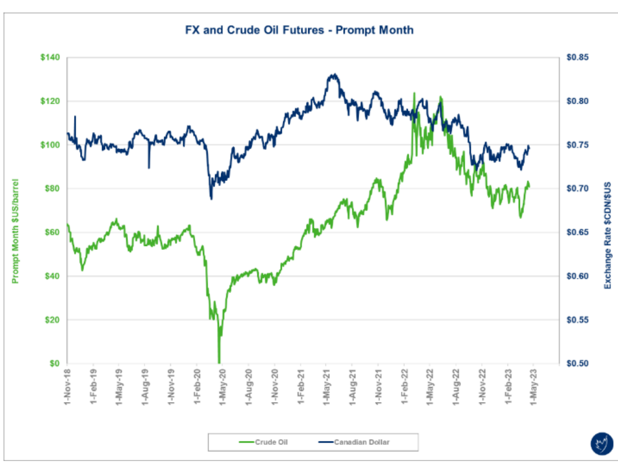


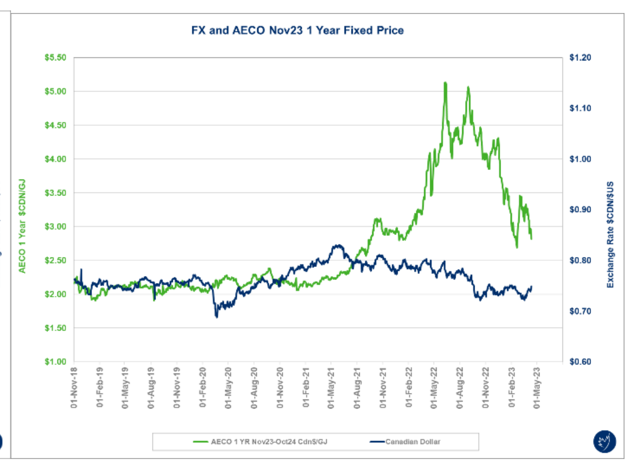
Storage graphs from RBN Energy LLC 2021 on April 18, 2023.

All these current storage balances lead to a more bearish sentiment on summer gas pricing in 2023 with less storage fill demand (US, Eastern and Western Canadian).

Crude Oil and Foreign Exchange: Impact on NYMEX and Dawn pricing – Mildly Bearish Near and Longer-term Mildly Bearish; Impact on AECO pricing Neutral Near and Longer-term

West Texas Intermediate oil pricing in early 2023 has remained range bound between $70 - $85 USD/b after reaching $120/b shortly after the war in Ukraine began a year ago. It fell back below $100/b as world demand faded (mostly China due to COVID relapse) and with OPEC actions to right size supply and the end of US Strategic Petroleum Reserve release ending in late 2022 the market seems to have settled for the time being. It continues to be difficult to forecast the end and outcome of the Ukraine war especially regarding world use of Russian oil over the next few years. However, this ongoing war has increased the world's pace to bring on more renewable energy sources and to continue to use of fossil fuels, mostly coal and oil to bridge the timing gap. The EIA forecasts the expectation of the US remaining a net exporter of petroleum products in the distant future (2050). Supply of oil especially from the Permian basin (Texas and Oklahoma) and the Baaken basin (N. Dakota) results in associated natural gas supply which is predominantly the reason for our continuing bearish sentiment in this category. A persistent oil price above $70/b (helped by President Biden's promise to buyback oil at this price) keeps US producers investing in E&P. Historically strong world oil prices have helped the Canadian buyer with a stronger dollar (offsetting the higher price of NYMEX priced gas (which mostly drives Dawn pricing). However, since mid-2022, the correlation appears to have brought the Canadian dollar down as WTI has fallen. 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 value has not contributed the AECO price run up or fall since mid-2021 to the present.

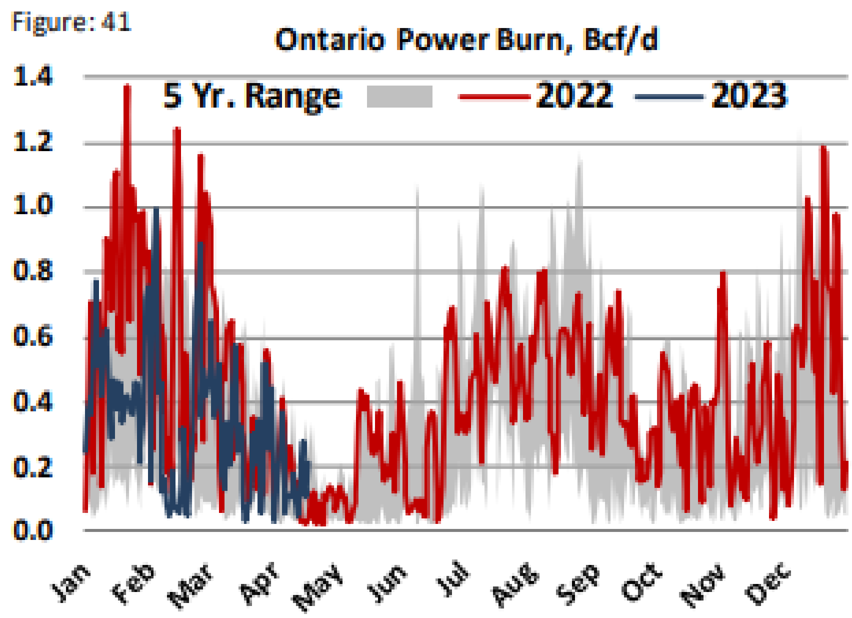




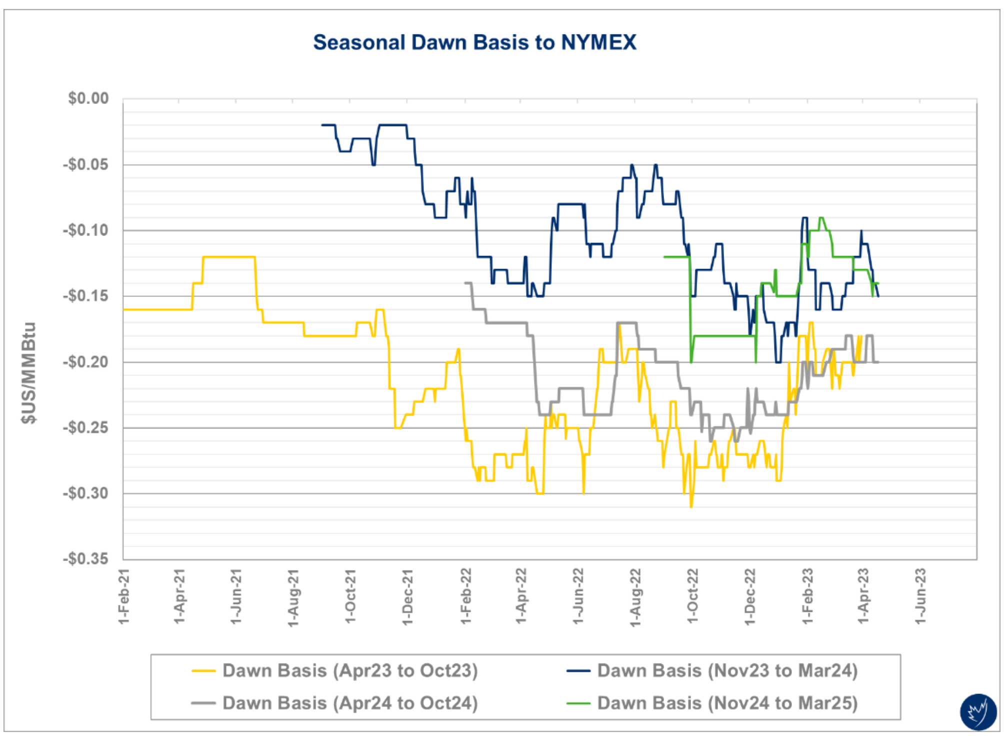
Dawn Market Hub Discussion

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 pipeline projects expected in the Dawn connected infrastructure 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. 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 winter at Dawn and at sites neighboring Midwest US (mostly Michigan). The mild weather in early 2023 also resulted in lower demand from Ontario gas fired power generation fleet however, 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. The forward price curves at Dawn continue to trade at a lesser discount to NYMEX in winters and summers starting November 2026 likely due to modest demand growth and/or risk of long-term pipeline contracts not being fully renewed.



Ontario Power Burn from RBN Energy LLC 2021 on April 18, 2023.



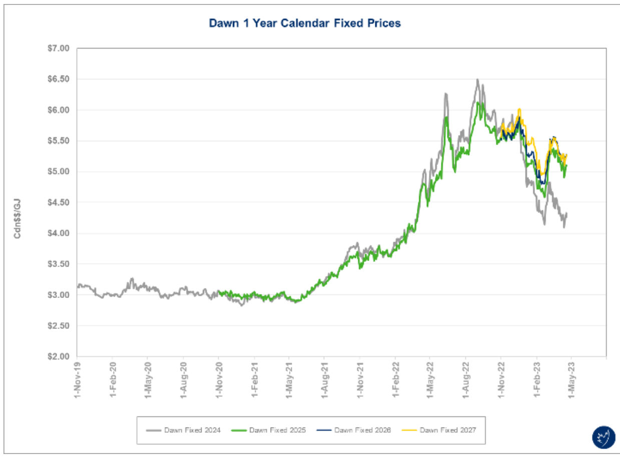
The current Dawn basis market looks like good value however based on EPCOR's lack of interest in purchasing forward basis, which is in USD, there is no purchase opportunity (based on this index). However, there continues to be upside price risk in the Dawn market from modest demand growth, no new supply, and the 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**	**Bullish**	**Bearish**	**Bullish**
Supply	**Bullish**	**Very Bullish**	**Bearish**	**Mildly Bearish**
Storage	**Very Bearish**	**n/a**	**Bearish**	**n/a**
Crude Oil	**Mildly Bearish**	**Mildly Bearish**	**Neutral**	**Neutral**
Overall	**Mildly Bullish**	**Bullish**	**Bearish**	**Mildly Bullish**

Near-term Summary – Mildly Bullish (NYMEX and Dawn), Bearish (AECO)

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 difficult to sustain year-over-year increases in supplies (at such low prices) make for a continued tightly supplied market moving forward. As a result, NYMEX and Dawn price outlooks in the short term are likely to move upward until supply growth is proven and sustained. The forward Dawn price for 2023 has upward volatility risk to the current forward prices shown in the graph below. AECO pricing could stay suppressed as storage fills and abundant supply continues to outpace new pipeline facility additions despite higher demands year-over-year from local power generation. 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.



Mid to Long-term Summary – Bullish (NYMEX and Dawn), Mildly Bullish (AECO)

In the U.S. the expectation of continued growth in LNG exports, modest economic growth, continued fuel of choice in power generation and slow to arrive supply growth (including supply from oil production) we expect pricing to move upward. The current forward landed cost of gas at Dawn exceeds $5.00 CAD/GJ for the calendar years 2025-2028. 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-term. Also supporting this view and not mentioned previously is the potential for existing pipeline capacity in NA to be closer to capacity in moving supply basin gas to all markets. Greenfield pipelines are exceedingly difficult to build due to environmental opposition and the likelihood that 30-to-40-year amortizations will not be accepted by regulators going forward. Capacity expansions may be limited to new capital for compression only and safety related “lift and replace” pipeline segments with larger diameter capacities increasing costs and longer in-service dates. Storage expansions may be necessary as well to meet the intermittent needs of natural gas fired power generation as it supports increasing grid support to renewables as well 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. AECO pricing follows the same sentiment as above only pipeline access from field zone to AECO appears to continue to be approved and implemented in reasonable timeframes. However, downstream of AECO there are limitations to accessing traditional downstream markets as mentioned above. 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 is lesser of a concern of WCSB supply meeting LNG Canada’s needs relative to the risk of US LNG expansion growth being met by timely supply.

Appendix D – 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.

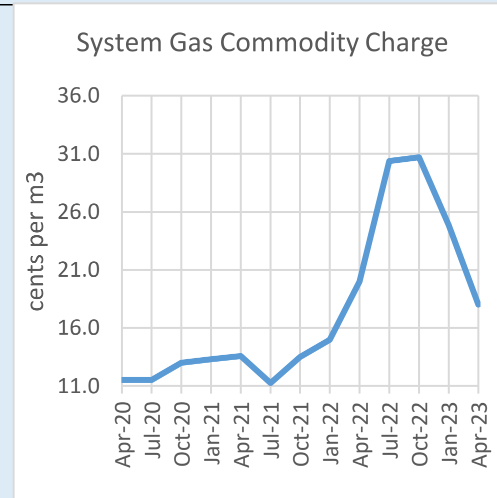
Steve Williams – Senior Energy Analyst, Supply & Risk Management

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 E – EPCOR Southern Bruce Performance Scorecard

OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	2020/21	2021/22	2022/23	3-yr Average
1. Cost Effectiveness	Policies & Procedures	Demonstrates consideration of timely pricing information and utility's ability to transact according to internal policies for managing counterparty risk	Procurement plan reviewed and approved as outlined in the policy	C	C	C	n/a
			Transacting counterparties have met appropriate credit requirements	100%	100%	100%	100%
	Price Effectiveness	Demonstrates diversity of supply terms within procurement plan through a layers approach to contracting Illustrates Price Stability	Distribution of procurement terms:				
			1. < 1 Month	18.7%	5.0%	11.0%	11.6%
			2. Monthly	81.3%	58.5%	48.9%	62.9%
			3. Seasonal	0%	36%	40.1%	25.5%
			4. Annual	0%	0%	0.0%	0.0%
			5. Reference Price History				n/a

OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	2020/21	2021/22	2022/23	3-yr Average
2. Reliability & Security of Supply	Design Day	Demonstrates ability to procure transportation assets required to meet design day demand	Acquired assets to meet design day	100%	100%	100%	100%
	Storage	Demonstrates execution of storage inventory strategy	1. % of storage level Sept 30th	99%	99%	100%	99%
			2. % of storage level March 31st	70%	16%	13%	33%
	Coordination	Demonstrates ENGPL ability to invest in capital distribution required to meet design day demand	Monthly meetings between gas supply, engineering, operations	4	12	12	n/a
	Communication	Ensure ongoing communications	Communication to ratepayers re material bill impacts	C	C	C	n/a
	Diversity	Demonstrate the diversity of the portfolio	1. % of contract vol. per delivery point	Dawn: 100% AECO: 0%	Dawn: 100% AECO: 0%	Dawn: 100% AECO: 0%	Dawn: 100% AECO: 0%
			2. # of unique counterparties	3	3	3	3
	Reliability	Demonstrate the reliability of the portfolio	1. Days failed to deliver to customers	0	0	0	0
			2.Days customer interrupted (1)	0	0	0	0
OEB Guiding Principle	**Performance Categories**	**Intent of Measures**	**Measures**	**2020**	**2021**	**2022**	**2023**
3. Public Policy	Supporting Policy	Reports public policy in EPCOR supply plan	1.Community expansion (% customer converted/unlocked vs. CIP)	15.40%	49.58%	86.37%	50.45%
			2. FCC	C	C	C	n/a
			3. RNG	n/a	n/a	n/a	n/a
			4. DSM	n/a	n/a	n/a	n/a

Notes : C= Compliant

Definitions:

1. Years refers to planning years (April 1st to March 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