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Projet de construction d'un complexe de liquéfaction de gaz naturel à Saguenay

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Canadian Natural Gas Market Assessment

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1. Executive Summary

GNL Quebec Inc ("GNLQ") is developing a liquefied natural gas (LNG) export facility at the Port of Grande-Anse in La Baie, in the Saguenay Area, Québec. The proposed facility name is Energie Saguenay ("the Project") and at full build-out is expected to have a total production capacity of 11 million metric tons of LNG per year, or approximately 1.55 bcfd of natural gas at the outlet of the LNG facility. Annual LNG exports would be equivalent to 568.5 bcf of natural gas per year, while feedstock required for the Project inlet is estimated at 1.64 bcfd, after accounting for natural gas consumption for compressors in transport.

This Canadian Natural Gas Market Assessment has been prepared by Wood Mackenzie in support of GNLQ's regulatory approval process, primarily to address whether "an assessment of the impact of the proposed exportation on Canadian energy and natural gas markets to determine whether Canadians are likely to have difficulty in meeting their energy requirements at fair market prices." Additionally, this report also addresses that the quantity of natural gas seeking to be exported in form of LNG by the Project "does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada." This report is based on Wood Mackenzie's independent North American Natural Gas H1 2019 Adjusted Base Case outlook prepared for GNLQ, and leverages Wood Mackenzie's decades of North American and Canadian natural gas market experience and knowledge, namely relating to market conditions, supply forecasting, demand forecasting and reserves in relation to other sources of alternative energy.

Wood Mackenzie leveraged extensive knowledge, experience and commercial expertise of the global and North American natural gas market to develop North American price impacts and additional supply required from the WCSB as result of the natural gas supply requirements of the Project. Wood Mackenzie maintains robust supply models which factor in break-even assumptions for producers, future drilling efficiencies and technology impacting costs and drilling inventory available for future production, among other variables to determine economic future production of natural gas across the globe and particularity in North America. Conversely, on the demand side, granular sector level forecasting is routinely performed which factors in multivariate regression analysis of variables impacting demand by sector and by province/state, with multiple assumptions surrounding future energy costs, energy transitions targets and technological impacts on energy demand globally. Regarding LNG assumptions, Wood Mackenzie leverages its know-how supporting global LNG projects to reach FID, seek financing and determine commercial agreements to develop a solid view of which projects are best placed to succeed and take FID. The forward view factors in a variety of key milestones and progress along the LNG development chain - LNG projects that have access to upstream supply, a robust feed gas procurement or sourcing strategy, a firm plan or contract in place for Engineering, Procurement, Construction (EPC) portion of the development and a solid marketing strategy, among other variables and/or advantages, are risked at a much higher chance of succeeding in the global LNG dispatch model. Additionally, Wood Mackenzie maintains detailed natural gas and related infrastructure databases which are routinely updated for latest developments, throughput cost information and utilization targets to determine the costs and available capacity of moving energy/natural gas from one location to another. When combining the proprietary Wood Mackenzie models and expertise in the global & North American natural gas and LGN value chain, Wood Mackenzie can effectively determine future natural gas supply, demand, natural gas flows, LNG exports and forecast prices across North America.

Advancements in exploration and development technologies targeting unconventional reservoirs have continued to post tremendous gains in recent years, allowing unparalleled natural gas supply growth across North America, including Canada. Despite lower commodity prices for natural gas in Canada and North America as a whole, producers have continued to extract increasing volumes of natural gas, from both non-associated and associated reservoirs and continue to add reserves from existing and new resources each year. Unconventional resources are forecast to make up the majority of new supply growth in the longer term through 2050, as conventional reservoirs continue to decline, and operators shift the bulk of capital to target unconventional plays. Going forward, technological advances to lower costs and the environmental footprint of natural gas extraction performance improvement are expected to continue, driving both economic and environmental efficiencies over the course of the forecast period.

Across North America, natural gas production growth is forecast to reach 172 bcfd by 2050, growing by 60% from 2019 levels of 108 bcfd. Near term production will be driven by associated gas from the Permian, Midcontinent and Rockies basins, while the call on non-associated gas, mostly from the Northeast of the US, is expected longer term as associated operators run out of core well targets, resulting in stagnating growth from associated supply. Non-associated natural gas is forecast to be the marginal supply source in the long term, with long term forecast prices reflecting the slightly higher cost breakevens for operators across North American non-associated basins.

In Canada, Wood Mackenzie believes strong, sustained supply growth will come from both British Columbia and Alberta in the Western Canadian Sedimentary Basin (WCSB), primarily driven by the ever-expanding Montney play, with some additions from the Duvernay, Deep Basin, Cardium and the Liard/Horn River plays. Supply will grow from 16.6 bcfd in 2019 to 27.1 bcfd through 2050, an increase of 63% from 2019, with the Montney peaking at 14 bcfd of supply. Liquids-rich focused area economics have driven near term operator supply portfolios and the remaining core locations of liquids-rich gas are forecast to decline post-2038, driving peak production in liquids-rich areas. Drier, non-associated gas plays from the Liard/Horn River basin are forecast to account for the bulk of supply additions post-2038.

To balance the swelling supply available from both associated and non-associated gas, North American demand growth is forecast to be driven by exports, primarily from LNG but also via gas pipelines to Mexico as well. North American domestic demand, excluding exports, is forecast to grow by 28% from 2019 levels of 95 bcfd, reaching 122 bcfd by 2050, with the industrial and power generation sectors responsible for a majority of the increase. Exports, whether LNG or gas pipeline exports are forecast to be a critical demand sector to balance overall North American natural gas supply growth – exports of natural gas are estimated to increase from 11 bcfd in 2019 to 52 bcfd by 2050, a 383% increase to fill additional global natural gas fuelled by the transition to a less carbonized world.

Canada's natural gas demand evolution follows similar themes forecast for North America, albeit at a stronger pace; domestic demand increases are driven by the industrial sector, primarily for use in the oil sands extraction industry with some increases for petrochemical feedstock, metals/mining consumption and natural gas fired power generation while LNG exports are set to balance the abundant supply growth in the WCSB. Domestic demand is forecast to grow 48%, from 11 bcfd in 2019, reaching 17 bcfd by 2050, with industrial demand increasing by 57%, from 5.3 bcfd in 2019 to 8.3 bcfd in 2050. LNG exports grow to 9 bcfd by 2050 as more projects are forecast to come online throughout the forecast period, again as in the United States, to balance significant increases in natural gas supply.

The tremendous growth of unconventional resource supply in the United States, primarily in the Northeast of the US and from associated supply in the Permian, has shifted traditional supply patterns, impacting Canadian gas transmission line natural gas exports to key US demand markets. As the US has become more self-sufficient, Northeast supplies have looked to new demand markets to balance supply increases, pushing northward into Canada, west into the Midwest markets and south to the key demand centres in the US Gulf Coast (USGC). This has resulted in significant gas-on-gas competition and has impacted Canadian natural gas transmission line exports to the downside – Wood Mackenzie believes this shift in the market will continue, with net gas transmission line exports from Canada continuing to decline, reaching 2.6 bcfd in 2050, from 5 bcfd in 2019. This phenomenon highlights the competitiveness of North American natural gas resources and brings forward the increasing pressure Canadian natural gas faces from growing supplies in the US.

Leveraging long term supply expectations, demand evolution and market dynamics through 2050, Wood Mackenzie believes North American natural gas prices will continue to be competitively priced over the long-term with the 2019-2050 average Henry Hub price forecast at US$3.96/mmbtu ($2019 real), with prices expected to remain below US$6.00/mmbtu through the forecast period. Similarly, AECO prices are forecast to average US$3.04/mmbtu over the forecast period and peak at US$4.87 in 2050. This price outlook reflects reasonable market conditions with the forecast of lower volatility primarily driven by the abundance, predictability and fast supply response of North American unconventional gas supplies able to meet both domestic and export demand.

The estimated Canadian resource size is sufficient to allow for the continued supply to Canadian domestic consumers, including net pipeline exports to the US for a duration of 205 years, when using 2018 demand and export figures. This number increases to 304 years when factoring in only 2018 Canadian domestic consumption, ex-US imports. As LNG Canada has reached final investment decision (FID) and is currently under construction, Wood Mackenzie assessed the Canadian resource estimates against a case which combined current Canadian domestic demand (inclusive of US exports), combined with under construction Canadian LNG export facilities and the proposed volumes required by GNLQ – this scenario resulted in 157 years of available supply. Assessing the size of total North American resources against 2018 North American domestic consumption yields a resource life of 106 years, which, in Wood Mackenzie's belief, will adequately supply all forecast demand through the end of the study period to 2050 in Canada, the rest of North America, and any additional demand as a result of GNLQ's projected exports.

Using Wood Mackenzie's proprietary global and North American supply, demand, infrastructure cost/tariff and gas pipeline competition models and adjusting the base case assumptions from the Long Term H1 2019 forecast to include the impact of the additional 1.55 bcfd required by the Project, Wood Mackenzie was effectively able to determine additional supply impacts from the WCSB including impacts to Canadian prices. Under the adjusted base case scenario, the Project feed gas needs result in only an additional 0.08 bcfd of incremental WCSB production above the WM H1 2019 base case – this is due to the diversion of natural gas pipeline export flows away from the US Lower 48 (Midwest region) and Eastern Canadian markets and towards supplying the Project's needs. The export flows out of the WCSB that are redirected are replaced with additional gas from US Lower 48 plays, primarily from the US Northeast, which results in a small upward AECO price impact of $0.35/mmbtu above the WM H1 2019 Base Case over the 2025-2040 timeframe.

In conclusion, the North American and Canadian natural gas markets show characteristics of abundant and competitive natural gas supplies able to meet domestic and export demand at economical and stable prices. Ultimately, the ample volume of natural gas supply in Canada will exceed domestic demand requirements, under construction LNG export demand and GNLQ's proposed export volume requirements, for the foreseeable future.

2. Introduction and Energie Saguenay LNG Project Overview

2.1 Purpose of the Canadian Gas Market Assessment Report

The Canadian Gas Market Assessment has been prepared to assist GNLQ in their regulatory and environmental process at the Federal level. The Canadian Natural Gas Market Assessment will address that the quantity of natural gas to be exported by GNLQ "*does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada*"[1]. This report will also assess the potential incremental Canadian gas production due to the operations of the Énergie Saguenay project in comparison to the Wood Mackenzie North American Natural Gas H1 2019 Base Case outlook.

2.2 Énergie Saguenay LNG Project Overview

GNLQ is developing an LNG export facility, the Énergie Saguenay Project (the "Project"), at Port Saguenay, Quebec. The Project will include a natural gas liquefaction facility (the "Facility") and related infrastructure and facilities to enable export of LNG to international markets. The terminal will be installed on lands belonging to the Administration Portuaire de Saguenay (Saguenay Port Authority), adjacent to the existing Grande-Anse port facilities, which is located 15 km east of Chicoutimi and 6 km north of La Baie on the southern bank of the Saguenay River. At full build-out the Facility is expected to have a total production capacity of 11 million metric tons of LNG per year. Annual LNG exports would be equivalent to 568.5 bcf of natural gas per year, feedstock required for the Project inlet is estimated at 1.64 bcfd, after accounting for fuel used in pipeline transport. The Project is planned for start of operation in 2025. The forecast term in this report extends to 2050.

Natural gas supply for the Project is expected to be sourced primarily from the Western Canadian Sedimentary Basin ("WCSB") located mainly in Alberta and British Columbia. Natural gas supply for the Project will be accessed through third-party agreements with gas producers, marketers, and aggregators. Third party purchases are expected to be transacted at a variety of Canadian locations though primarily at the liquid AECO Hub. Figure 2.1 shows the location of the Project and connectivity to market hubs.

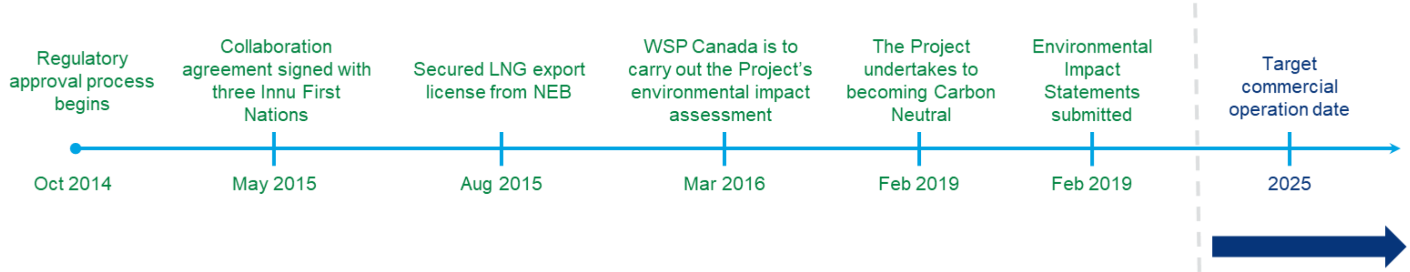
[1] Section 118 of the NEB Act, as quoted by the NEB in its Letter Decision issuing an LNG export licence to LNG Canada Development Inc. on February 4, 2013 (File OF-EI-Gas-GL-L384-2012-01 01), at 3. The Board stated that the quoted material is what the Board is "legally mandated and authorized to consider" when assessing a gas export licence application.

Figure 2.1: Map of the WCSB, TC Energy Mainline System, Key Gas Pricing Hubs, Gazoduq Gas pipeline & Energie Saguenay LNG

2.2.1 Project Structure & Status

The Project is privately held by GNL Quebec Inc, company incorporated under the law of Quebec. The Project has secured an LNG export license from the CER (formerly NEB) in 2015, with a Governor-in-Council approval in May 2016 and is currently in the process of obtaining other necessary regulatory approvals.

Figure 2.2: Énergie Saguenay Project Regulatory Timeline



Source: https://energiesaguenay.com

Source: https://gazoduq.com

3. Wood Mackenzie North American Natural Gas Model Overview

Wood Mackenzie generates a long-term forecast of annual and monthly North American natural gas prices twice yearly at 30+ liquid natural gas physical trading/exchange points (hubs) which are developed as basis differentials to the key marker of Henry Hub, based on supply and demand fundamentals impacting natural gas balances across North America. The forecast factors in Wood Mackenzie's extensive experience and deep understanding modelling upstream oil and natural gas developments across conventional and unconventional basins, primarily rooted in economic drivers and commercial behaviour of market participants. Additionally, the outlook of prices incorporates infrastructure capacities, bottlenecks, and existing & future commercial fees (tariffs/tolls) of hydrocarbon separation, gathering (compression), processing and transport from key supply centers to end use demand points, including views of future required infrastructure capacities and costs required to sustain forecast fundamental supply demand balances.

Wood Mackenzie uses a proprietary upstream break-even supply cost, volume and levelized operating cost model, the LTM model for more than 450 supply nodes, which is optimized for historic and expected finding and development costs, factoring in acreage spacing, well densities, geological properties of individual formations and benches, type curve analysis and technological advances in drilling and completions techniques, among other variables. The LTM model generates future economically available supply volumes across the North American continent from both conventional and unconventional basins and from associated and non-associated natural gas basins, plays and sub-plays which are then used to model future price outlooks.

On the demand side, Wood Mackenzie utilizes a proprietary, monthly multi-variate regression demand model which forecasts natural gas demand by sector and by state, using historical inputs from various federal & state/provincial government agencies, publicly disclosed information from relevant companies, and other verified sources of information. Each demand sector by state is regressed against relevant macro-economic and fuel competition variables, which may include state level gross domestic product growth forecasts, industrial demand projections, energy intensity and competition from renewable sources, natural gas efficiency factors and other applicable variables. Other variables, namely carbon emissions targets, adoption and regional specific regulations impacting demand are factored into each demand sector and region to attain a wholistic view of future demand.

Wood Mackenzie maintains an outlook of existing, under construction, announced and to be decommissioned facilities relevant to natural gas supply and demand, including gas gathering & processing facilities, indigenous and export/import trunkline gas transportation infrastructure, LNG export terminals, thermal power plants, storage facilities and other necessary infrastructure in the North American natural gas market. These databases and outlooks are updated and on a quarterly basis, with each facility given a status label, whether existing, suspended, under construction, probable & possible, dependent on the development stage of the facility and Wood Mackenzie's extensive experience forecasting future project success factors. Facilities capital and operating costs are transformed into relevant tariffs, with outlooks on regulated, non-regulated and negotiated tariffs on each segment of the integrated North American natural gas transportation grid maintained quarterly, including views on contracted capacity, interruptible capacity available and ultimate facility/gas pipeline seasonal capacity.

The LTM, demand model and facilities tolls & contracting outputs are then input into a proprietary in-house version of RBAC's Gas Pipeline Competition Model (GPCM) which generates the basis price forecasts by optimizing natural gas pipeline flows across the natural gas grid dependent on available capacity, cost of transportation, supply basin and demand locations Pipelines are modelled to have adequate capacity to flow gas from supply sources to demand centers, though in instances where future capacity reaches full utilization beyond expected gas pipeline developments, Wood Mackenzie models generic supply corridors to relieve expected bottlenecks. Under these circumstances, supply, demand and future gas flow has been rigorously scrutinised against Wood Mackenzie's natural gas market knowledge, experience and market participant behaviour for rationality. As the model extends through 2040, the GNLQ adjusted base case used the existing GPCM model and extrapolated the outputs to 2050 for the purposes of this report based on conservative future industry assumptions.

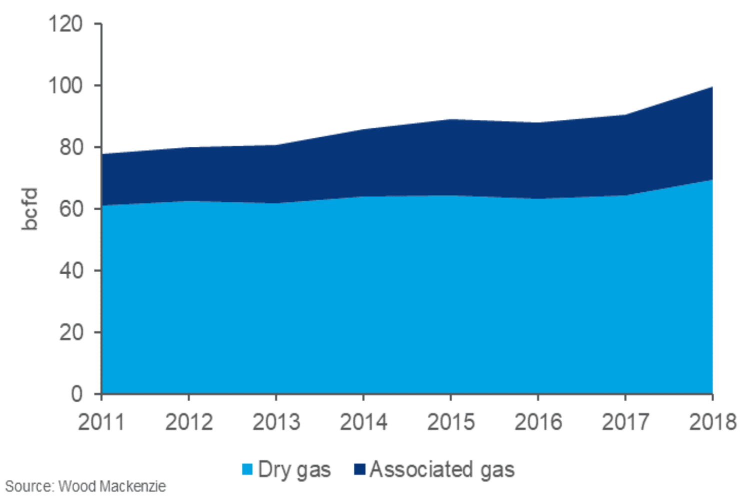
4. North American Gas Resources

In order to sufficiently assess whether the natural gas to be exported by GNLQ "*does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada*", Wood Mackenzie performed a robust, independent analysis of the fundamental drivers impacting supply and demand balances. Typically, Wood Mackenzie would use the current outlook from its North America Gas Service (H1 2019) as the basis of any supply/demand reporting; however, for the purposes of the Canadian Gas Market Assessment, the North America Gas Service (H1 2019) forecasts were extended from 2040 to 2050 to factor in a 25-year project life of GNLQ facilities (herein referred to as the "Adjusted Base Case").

4.1 North American Natural Gas Resources

The North American "Unconventional Resource Revolution" is a result of series of technical discoveries aimed at increasing drilling productivity and profitability in oil and gas unconventional reservoirs and plays. Unconventional extraction technologies have allowed the United States and Canada to maximize crude oil and natural gas production, which has reduced the region's dependence on energy imports from other countries, while allowing for significant exports of natural gas, LNG, natural gas liquids and light crude oil. In 2018, unconventional gas production accounted for 31% of total United States gas production and for 26% of Canadian gas production. At the same time, associated gas production from oil unconventional plays has risen as producers have focused on liquids-rich plays. In the last 5 years, associated gas production in the US and Canada ("North America") grew by 11.3 bcfd, compared to dry gas production growth of 7.7 bcfd.

Figure 4.1: North America Historical Associated vs. Dry Gas Production



Source: Wood Mackenzie

There are several factors driving North American unconventional production growth compared to other countries along with technological developments that are globally available. North America's hydrocarbon rich unconventional plays, unmatched capital and expertise in the oil and gas industry, and existing hydrocarbon processing and transportation infrastructure network helped accelerate the unconventional revolution. In the United States, regulations that help support the oil and gas industry and landowner mineral rights also support North American operators to continue to add reserves despite a low-price environment.

4.1.1 Unconventional Gas Resource Characteristics & Evolution

Unconventional gas emerged following the gas shortages of the 1970s as a result of United States federal government initiatives as an energy supply alternative. Initially a product of a costly hydrocarbon extraction process, unconventional gas became commercially viable in the Barnett Shale formation in 1998. The combination of hydraulic fracturing and horizontal drilling started the “Unconventional Resource Revolution” and have expanded the technically recoverable resources both in North America and globally.

One of the main processes that enabled the Unconventional Resource Revolution was horizontal drilling, a process of drilling a well from the surface to a subsurface location above the target reservoir, and then deviating the well horizontally to reach the main hydrocarbon target. A horizontal reach exposes significantly more reservoir rock to the well and results in more hydrocarbon recovery, however costs significantly more than to drill a vertical well in the same location.

Hydraulic fracturing, or “fracking”, a well stimulation technique, began as an experiment in 1947, and has been increasingly commercially viable. In fracking, the rock is fractured by a pressurized liquid allowing hydrocarbons to flow more freely. It has been a controversial topic in many countries where the economic benefits have been weighed against potential environmental impacts. Another technical innovation that has improved gas recovery has been multi-well pad drilling, a drilling practice that allows multiple wellbores to be drilled from a single pad. It is mainly used in conjunction with horizontal drilling to maximize hydrocarbon recovery from a single unit. These combined innovations have resulted in significantly increased hydrocarbon extraction from unconventional formations by boosting well efficiency and productivity and reducing costs and have been applied successfully in North America to more than 430,000 wells. Over the course of the last seven years, unconventional formation stimulation via fracturing technology, where less permeable formations are stimulated using the technology of pumping high pressure water, extremely minute sand particles and other solvents into the wellbore to increase ultimate hydrocarbon flow has improved overall recovery, has increased recoveries from unconventional reservoirs across North America. As operators have experimented with various frac stages and intensity over the years, ideal combinations of varying frac stages and pumped stimulations have resulted in decreasing completions costs resulting in more economic wellhead economics on a per unit basis.

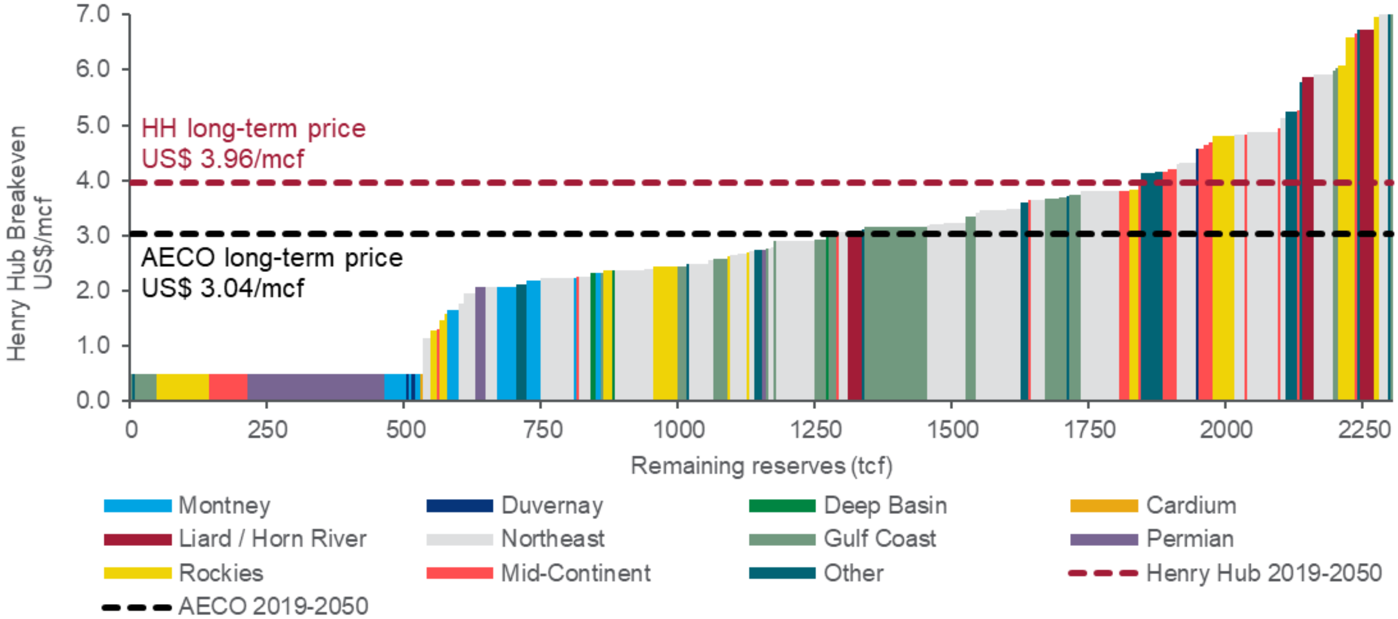
4.1.2 Economics

North America key basins and unconventional plays hold some of the best well economics in the world. Wood Mackenzie estimates 1,842 tcf of North American gas reserves are economic under the H1 2019 Adjusted Base Case long term US Henry Hub natural gas price in Figure 3.2. Western Canada also features some of the most cost competitive supplies, driven by:

- **Attractive geology** – Diverse hydrocarbon mix, shallow formation depth, and high yields underpin robust liquids production in several liquid-rich WCSB plays, including the Montney, Duvernay, and Cardium.
- **Cost and productivity optimization** - High competition and depressed AECO gas prices foster innovations that improve liquids recoveries and lower cost barriers to achieve attractive well economics. Along with a continued focus on capital discipline, WCSB plays consistently demonstrate some of the best well economics in North American plays.
- **Currency exposure** – WCSB well economics benefit from Canadian currency as the USD/CAD exchange rate remains strong. This adds to the basin attractiveness compared to other US basins and plays.

The economics of each WCSB plays are discussed further in Section 5.1.

Figure 4.2: North America Gas Breakeven and Remaining Reserves



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

Long-term HH and AECO prices are calculated by taking the average of Wood Mackenzie's GNLQ adjusted base case price forecast from 2019 to 2050
Associated gas breakevens are indicative for display purposes

4.2 North American Supply and Demand Fundamentals

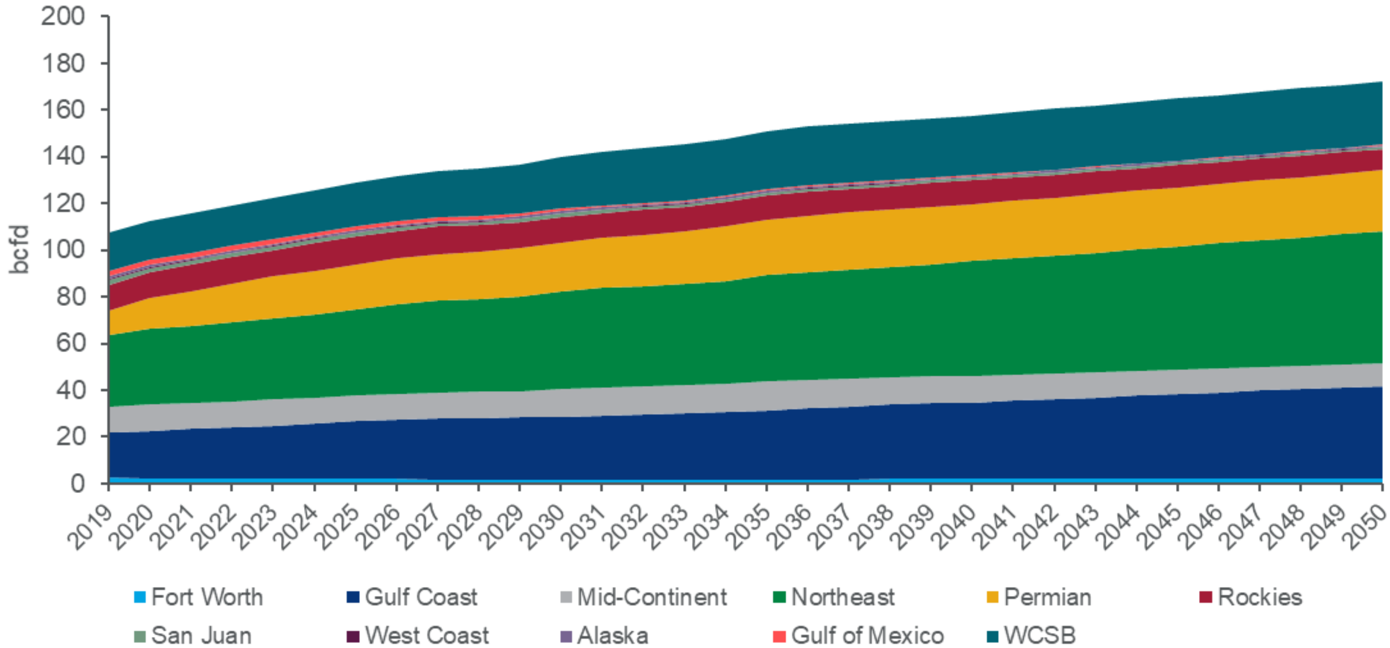
As the Canadian gas market is highly linked with the North American one, with Canadian natural gas hub prices moving in high correlation to prices in the USA, this section aims to cover the fundamental drivers on both the supply and demand side that impact natural gas prices across North America and particularly Canada. The key objective is to describe shifting natural gas supply and demand patterns away from traditional flows due to the advent of new unconventional natural gas supplies developed, in current development and forecast future development across the outlook timeframe (2050) and ultimately the impacts to future price outlooks. Wood Mackenzie's supply and demand balances are modelled with the assumptions that required infrastructure to allow for the gains in supply and demand will be developed in the future, though the model takes into consideration projects and regions where local opposition to hydrocarbon projects and handicaps future production/demand in those regions accordingly.

4.2.1 North American Supply

Natural gas supply in North America is dynamic as associated gas plays battle with non-associated dry gas plays for market share. Wood Mackenzie estimates North American (US and Canada) gas production at 108 bcfd in 2019 and overall production is set to grow steadily over the next 30 years, reaching 172 bcfd by 2050. Over 70% of the current total supply is attributed to the four key supply basins: Gulf Coast, Northeast, Permian and WCSB. These four basins remain the main drivers for long term supply growth as production from these four basins will make up more than 85% of total production by 2050.

The key driver near term will be associated gas, which will see significant growth between 2019 and 2025. The Permian basin alone will deliver ~9 bcfd of additional gas along with other associated gas supply from plays like the Niobrara, Bakken and Eagle Ford. Dry gas plays such as the Marcellus and Utica in the Northeast, the Haynesville and plays in the WCSB will experience accelerated growth post-2025 as associated plays begin to exhaust well inventories. As dry gas drilling is more muted in the medium term due to the continued influx of associated gas supply, dry gas plays will be able to ramp up longer term as the need for non-associated gas increases.

Figure 4.3: North America Gas Production Forecast



Source: Wood Mackenzie adjusted GNLQ base case

A mature oil producing region that encompasses West Texas and Southeast New Mexico, the Permian Basin is the fastest growing oil basin in the world. Attractive oil breakevens in the $30-50/bbl range drive substantial tight oil drilling and associated gas production in the region. As a result of rampant tight oil drilling activity, associated gas production displays significant short-term growth, rising from 10.6 bcfd in 2019 to 19.4 bcfd in 2025. Beyond 2025, activity shifts to higher gas-to-oil ratio (GOR) areas in the Permian as core tight oil acreage is exhausted, resulting in a resilient associated gas production curve reaching near 26.2 bcfd in 2050.

Continued development of the Marcellus and Utica Shale has firmly positioned the Northeast US as the largest gas producing region in North America through the end of the forecast period. Attractive economics underpin the Marcellus and Utica plays, with many areas achieving gas breakevens well below $2.00/mmbtu. Northeast gas production rises from 30.7 bcfd in 2019 to 37.0 bcfd in 2025, with the focus in both plays being on the areas that produce lean gas. After 2025, the region continues to exhibit sustained increases, growing by roughly 19.5 bcfd, reaching 56.5 bcfd in 2050.

Gas production in Western Canada has historically surpassed domestic demand, with exports playing a key role in balancing gas markets. In 2007-2009, advances in shale gas extraction technologies propelled WCSB supply growth in unconventional plays to replace declining conventional production and meet growth requirements. This has resulted in the majority of drilling and, in turn, production growth, moving to the northwest region of the basin.

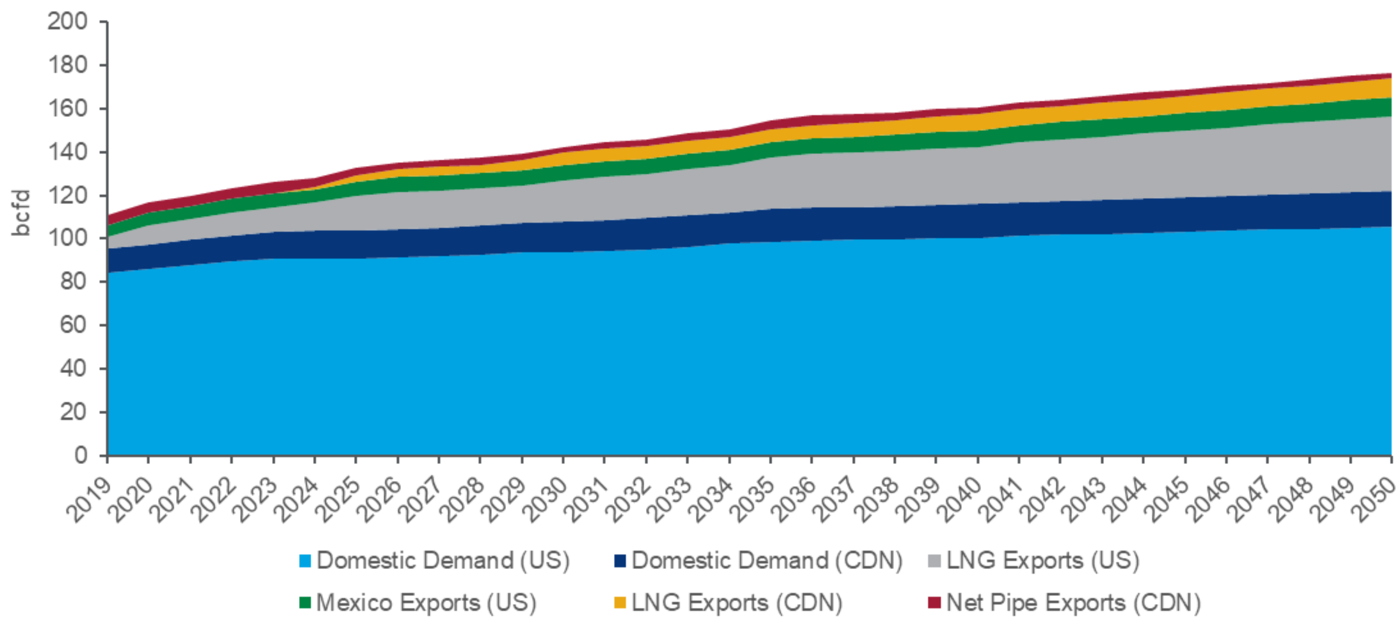
WCSB production remains resilient as liquids-focused drilling allows for more robust wellhead economics. Moving forward, WCSB supply growth will come primarily from the Montney play, supplemented with some additional growth from the Duvernay, Deep Basin, and Cardium plays. WCSB production is expected to grow by 10.5 bcfd, from 16.6 bcfd in 2019 to 27.1 bcfd by 2050 primarily driven by expansion in the Montney and Deep Basin. Production growth is expected to be flat through the next 2-3 years until infrastructure upgrades on the NGTL system increase pipeline export capacities.

4.2.2 North American Demand

North America gas supply growth is forecast to more than double the US and Canada domestic demand growth (64 bcfd vs 27 bcfd, respectively) in the period from 2019 to 2050. Domestic demand shows modest growth over the forecast period, both in the US and Canada, adding 21 bcfd,and 5 bcfd respectively. In order to consume the significant low-cost supply push, most demand growth will come in the form of exports. In the US, LNG exports and pipeline exports to Mexico will grow 29 bcfd and 3 bcfd, respectively, while in Canada, LNG exports will add 8.8 bcfd and gas pipeline export will see a slight decrease of 2 bcfd by 2050 as supply patterns in the US shift.

In Canada, LNG exports will add 8.8 bcfd, while pipeline exports will see a decrease of 2.2 bcfd by 2050 as competition from US L48 gas, particularly the Marcellus and Utica plays in the Northeast US pushes into traditional Canadian pipeline export markets. Industrial demand is the main driver for Canadian indigenous demand growth, as oil sands demand leads the industrial sector gains over the long term. By 2050, 4.4 bcfd of gas will be needed to support oil sands operations, accounting to 16% of total demand. Other industrial demand, namely in the petrochemical, mining, steel and pulp/paper industries among others, will account for 14% of total demand by 2050. Residential and commercial gas demand in Canada remains relatively flat throughout the forecast period while power demand ramps up in the short term as a result of coal to gas switching; however, declines in the long term with the decline of gas fired generation capacity additions in lieu of renewable capacity penetration.

Figure 4.4: North America Gas Demand Forecast



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

4.2.3 Shifting of Historical North American Supply Patterns and Trade Dynamics

Although most of the gas consumed in the US is produced domestically, US imports modest quantities of natural gas from Canada to help supply domestic demand with over 90% of the total US imports delivered from Canada via gas transmission lines (and small quantities delivered to the US Northeast from LNG imports during peak winter periods).

Canada has traditionally relied on pipelines exports to the US L48 market to balance abundant natural gas production, with several pipelines connecting the vast resource in the WCSB to US L48 demand regions. Historic Canadian natural gas exports have primarily targeted the US Westcoast, Midwest and some Northeast US demand markets, via various pipeline interconnections as described in Section 7.

However, starting in 2007, imports of natural gas from Canada began to decline as a result of rapidly growing US domestic production from unconventional natural gas and oil plays across the US Lower 48 states ("US L48"). Additionally, there has been a shift in traditional supply sources, with gas production from Northeast US pushing into Eastern Canada, the US Midwest, and the US South due to the favourable economics and gas transmission line connections linking the key Northeast US Marcellus and Utica plays to demand markets. Using the latest Woodmac H1 2019 natural gas assessments, Northeast breakevens continue to lead North American unconventional non-associated gas plays, averaging 1.89 $/mmbtu throughout the forecast period.

With recent pipeline reversals exporting U.S. gas into Eastern Canada and the newly commissioned Rover and Nexus pipelines targeting the Dawn market, Marcellus/Utica production is pushing further into eastern Canada (i.e. at export points such as Niagara, St. Clair, Blue Water and Iroquois) and into the U.S. Midwest markets (which may further displace Canadian gas in this key U.S. market). Northeast gas is not only displacing WCSB gas, but the volumes of growth are also impacting WCSB ability to export pipeline gas to traditional Canadian markets through piped exports.

The shift in market dynamics is resulting in strong gas-on-gas competition with traditional Canadian natural gas export markets being squeezed by domestic US unconventional supplies. Over the forecast period, net gas transmission line exports from Canada to the US are forecast to decline from 5 bcfd in 2019 to 2.6 bcfd in 2050 as a result of the increases in US L48 production.

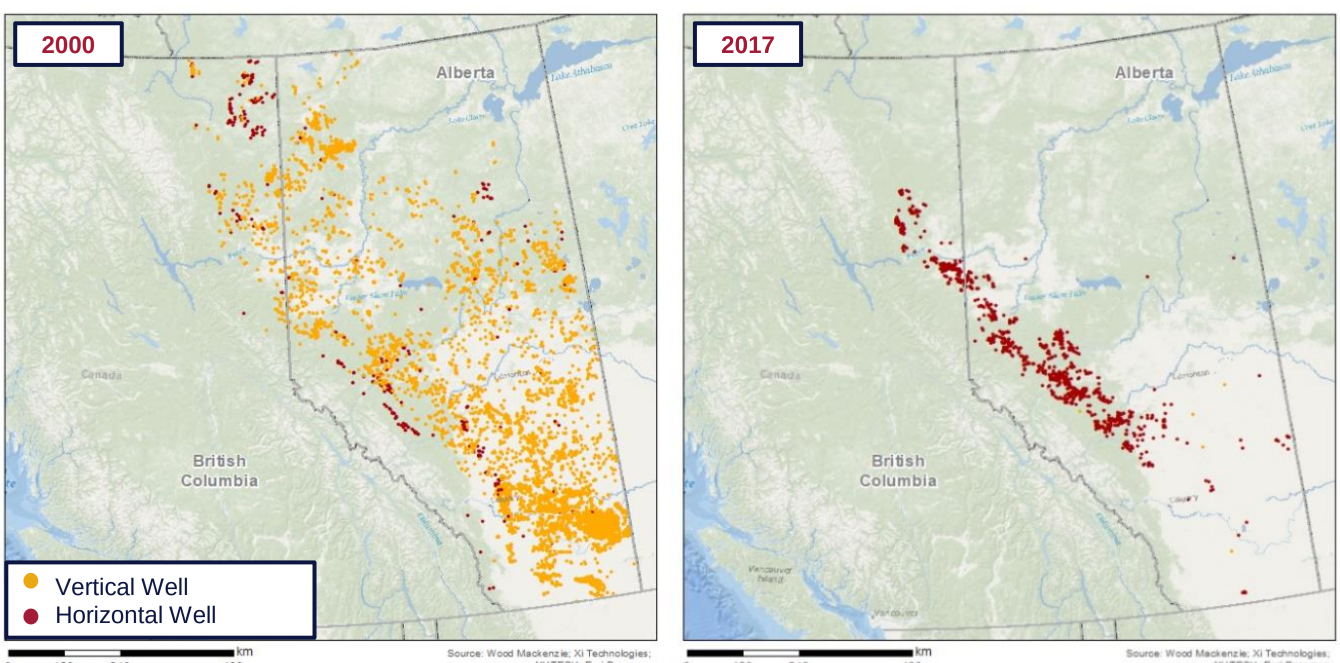
As the GNLQ project will be solely sourcing gas from the WCSB due to the proposed infrastructure connections of the Gazoduq pipeline, decreasing Canadian pipeline export outlooks to traditional markets in the US Midwest, Northeast and Eastern Canada will unlock both available supply and transportation capacity to feed the Project.

5. Overview of the Western Canada Sedimentary Basin (“WCSB”)

Gas production in Western Canada has historically surpassed domestic demand, with exports playing a key role in balancing gas markets. In 2007-2009, advances in unconventional gas extraction technologies propelled WCSB supply growth in unconventional plays to replace declining conventional production and meet growth requirements. This has resulted in most of the drilling and, in turn, production growth, moving to the northwest region of the basin.

This regional shift and concentration in production has constrained the existing Nova Gas Transmission Ltd. (NGTL) system, which was originally designed to move gas production spread across AB to key demand centres including domestic provincial demand, TC Energy Mainline flows to Eastern Canada, Northern Border (“NOBO”) and Alliance flows to the US Midwest, and Gas Transmission Northwest (GTN) via Foothills to the Pacific Northwest. As a result, TC Energy is currently in the process of redesigning NGTL’s system capacity to accommodate growing production from the Montney play in AB and BC as well as the increasing need for additional NGTL capacity to access the TC Mainline to Eastern Canada and US export gas transmission lines. Near term infrastructure constraints due to robust gas production resulting in continued maintenance to allow for increasing flows down the Upstream James River (USJR) pipeline segment on the NGTL system (key transport corridor to end use markets) have weakened WCSB natural gas hub prices considerably, with some operators choosing to voluntarily shut-in higher cost production (i.e CNRL, Painted Pony, etc.) due to challenged economics. To combat the egress issues at times of construction on the NGTL system, TC Energy received permission from the CER to implement the Temporary Service Protocol (TSP) during times of low demand (April-October). This change in firm and interruptible transportation capacity allocation effectively reduces upstream production at times of maintenance, resulting in a greater balance of supply and demand, allowing for less depressed pricing. Beyond potential short-term upside price impacts generated by implementing the TSP, Wood Mackenzie expects WCSB natural gas prices to gradually increase as additional gas pipeline export capacity to markets in the Us L48 and Eastern Canada is implemented through 2022 allowing for increasing gas pipeline exports out of the WCSB while the large LNG Canada export facility comes onstream in 2023/24, adding incremental export demand to Asian markets and driving WCSB gas production to steadily increase through the 2050 timeframe. Wood Mackenzie expects LNG directed production to increase 38% on a CAGR basis in the 2024-2030 period, with ultimate LNG orientated volumes growing 2.3% CAGR throughout the forecast period to 2050.

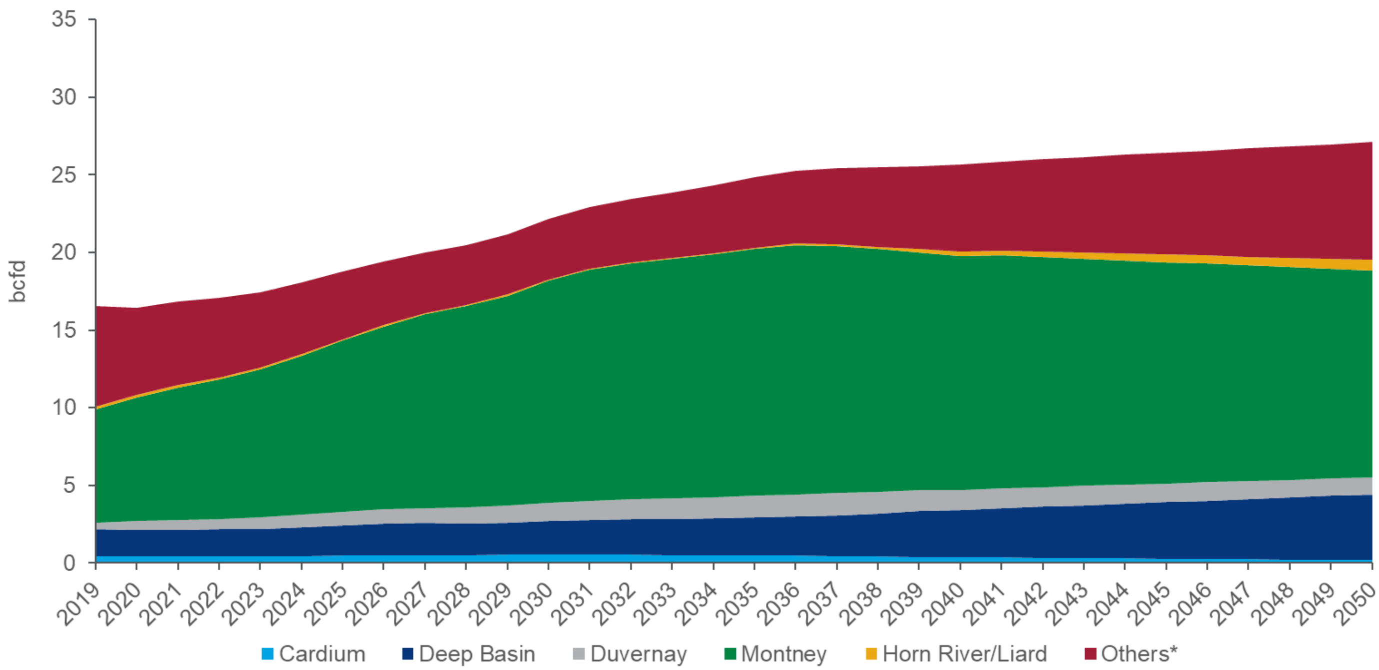
Figure 5.1: Evolution of WCSB Drilling Activity 2000 vs 2017



5.1 Production Outlook

Despite weak AECO gas prices due to insufficient near-term gas pipeline capacity limiting export flows and storage injections, WCSB production remains resilient as liquids-focused drilling allows for more robust wellhead economics. Moving forward, WCSB supply growth will come primarily from the Montney play, supplemented with additional growth from the Duvernay, Deep Basin, and Cardium plays. Wood Mackenzie expects WCSB production to grow by 10.5 bcfd, from 16.6 bcfd in 2019 to 27.1 bcfd by 2050 primarily driven by expansion in the Montney and Deep Basin. However, short-term, production growth is expected to be flat over the next 2-3 years until infrastructure upgrades on the NGTL system are implemented, namely the Upstream James River capacity expansion projects which are expected to add over 2 bcfd of intra Alberta gas transportation capacity in 2020-2021, and an increase in gas pipeline export capacities takes place through the end of 2021 coupled with greater intra-Alberta delivery capacity of 1 bcfd by the end of 2022. The key announced/under construction export capacity projects are the T-South expansion of 190 mmcfd, the AB/BC border expansion of 400 mmcfd, and the West Gate & North Bay Junction Expansion of approximately 600 mmcfd).

Figure 5.2: WCSB Gas Production Outlook



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

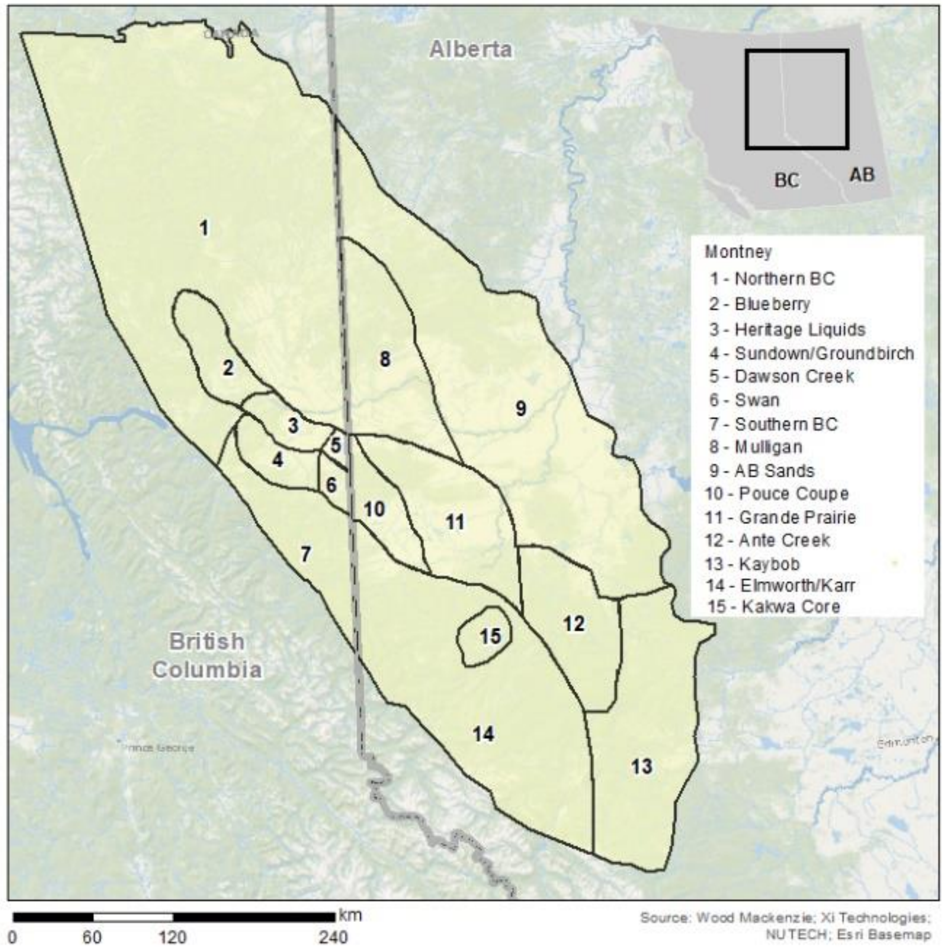
**Includes production from other supply basins in Manitoba, Saskatchewan, and production from AB and BC (e.g. Alberta Viking, Alberta Bakken) but not from the five key plays*

5.1.1 Montney

The Montney tight gas unconventional play straddles the British Columbia and Alberta border. Production in the Montney is largely gas-weighted; however, the hydrocarbon composition transitions from gas to condensate from west to east. It has well economics comparable with any unconventional play in the rest of North America, making it the most prolific play in Western Canada.

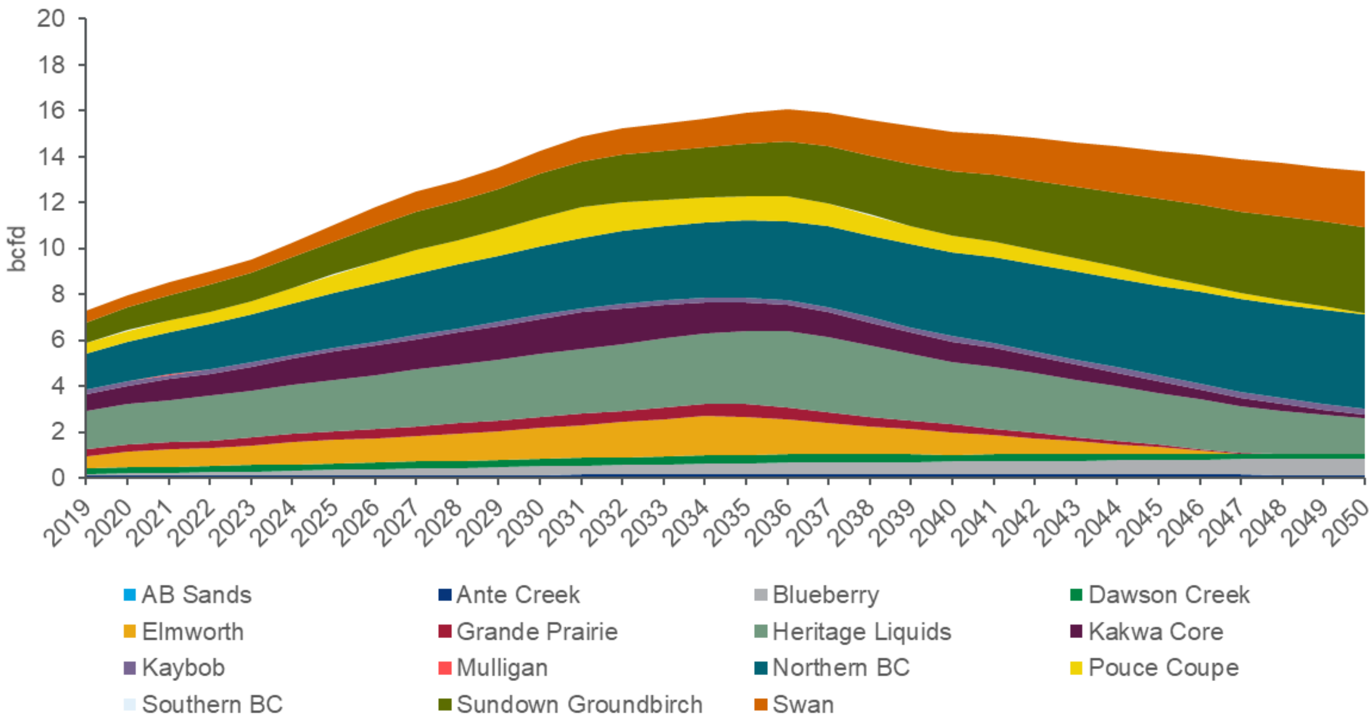
Wood Mackenzie segments each key play into several sub-plays, grouping wells that have similar characteristics. The division is based on geography, geology (depth, permeability, porosity), and well performance metrics such as gas-oil ratio and initial production (IP) rates. Sub-plays are also usually kept within province boundaries to capture the appropriate royalty and tax markers. In the Montney, 15 sub-plays are defined as shown in Figure 5.3, seven in BC and eight in AB.

Figure 5.3: Montney Play Map



Wood Mackenzie forecasts production in the Montney averaging 7.3 bcfd in 2019, accounting for 44% of total WCSB production. The liquid-rich sub-play, Northern BC, is the top producing sub-play, however, Heritage Liquids, Sundown Groundbirch, and Swan sub-plays will drive long-term production. Despite modest short-term activity levels in the WCSB, the Montney is expected to continue to grow, benefiting from high liquids content and a diverse operator profile. Montney gas production is expected to peak at 16.0 bcfd in 2036, followed by a gradual decline post-2036. Key limiting factors remain providing ample pipeline takeaway capacity to access markets, which we expect to be resolved over the next 2-3 years after which we expect the resource in the Montney will be more than sufficient to support Canadian domestic and export demand.

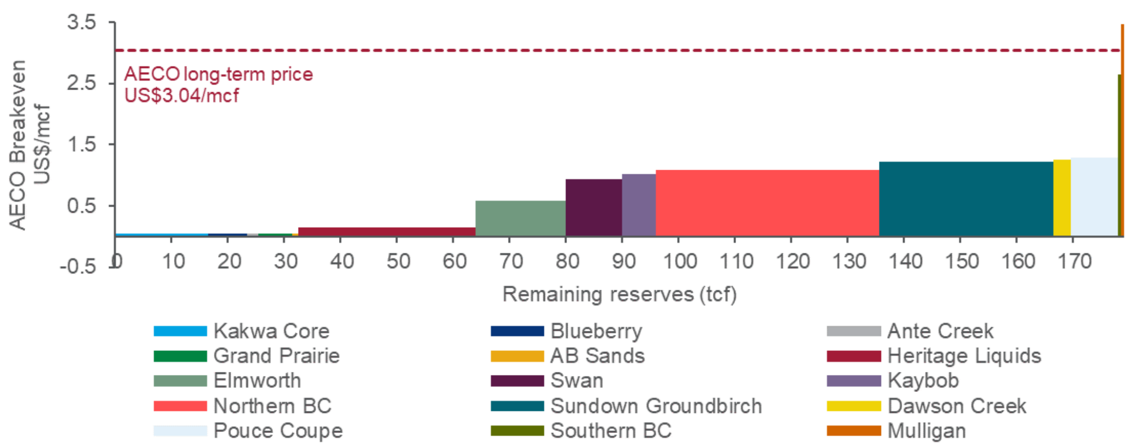
Figure 5.4: Montney Gas Production Forecast by Sub-Play



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

With one exception, all Montney sub-plays are commercial at long-term AECO prices of US$3.04/mcf. The liquid-rich sub-plays in BC Montney possess extremely attractive WCSB breakevens (as low as US$0.14/mcf), while holding more than 50% of the Montney's remaining reserves. Such low breakevens in these sub-plays are driven by a focus on liquids production, taking advantage of higher oil prices, reducing the gas breakeven price requirements to maintain adequate internal rate of returns (IRRs) for producers.

Figure 5.5: Montney Gas Breakeven and Remaining Reserves by Sub-Play



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

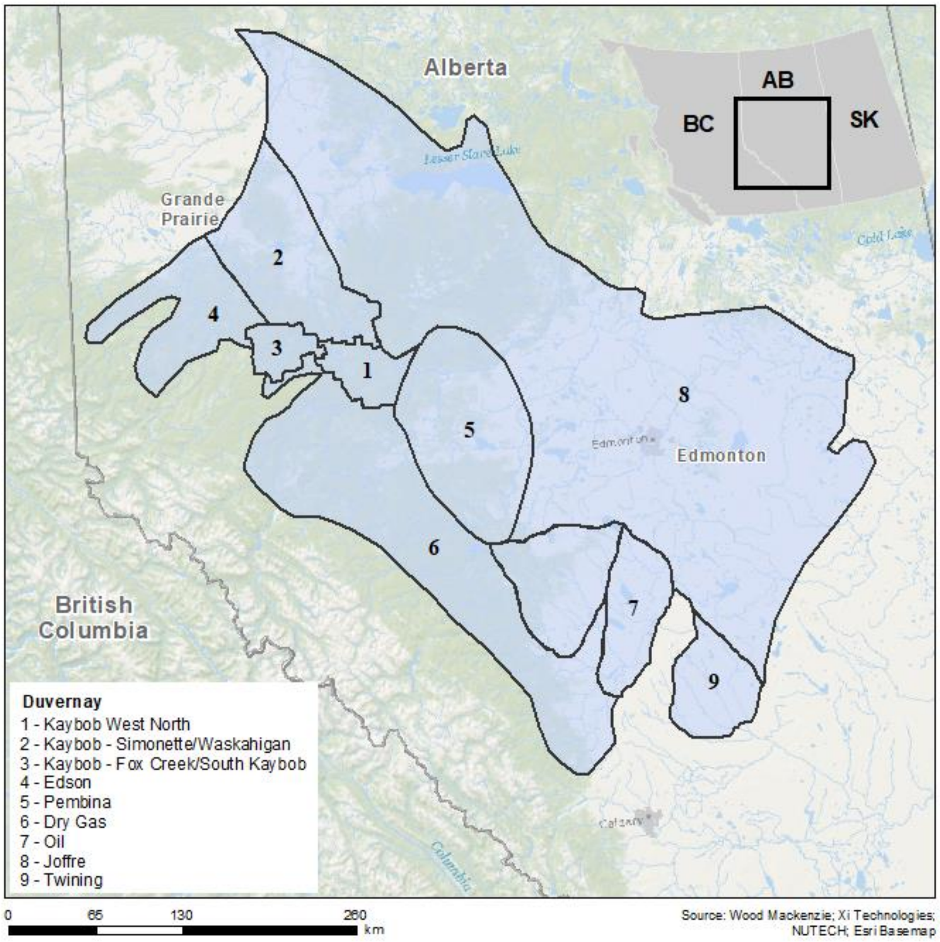
** Long-term AECO price is calculated by taking the average of Wood Mackenzie's GNLQ adjusted base case price forecast from 2019 to 2050*

*** Grande Prairie, Kakwa Core and AB Sands are indicative for display purposes; these three sub-plays are liquids-driven with AECO breakevens of US$0/mcf*

5.1.2 Duvernay

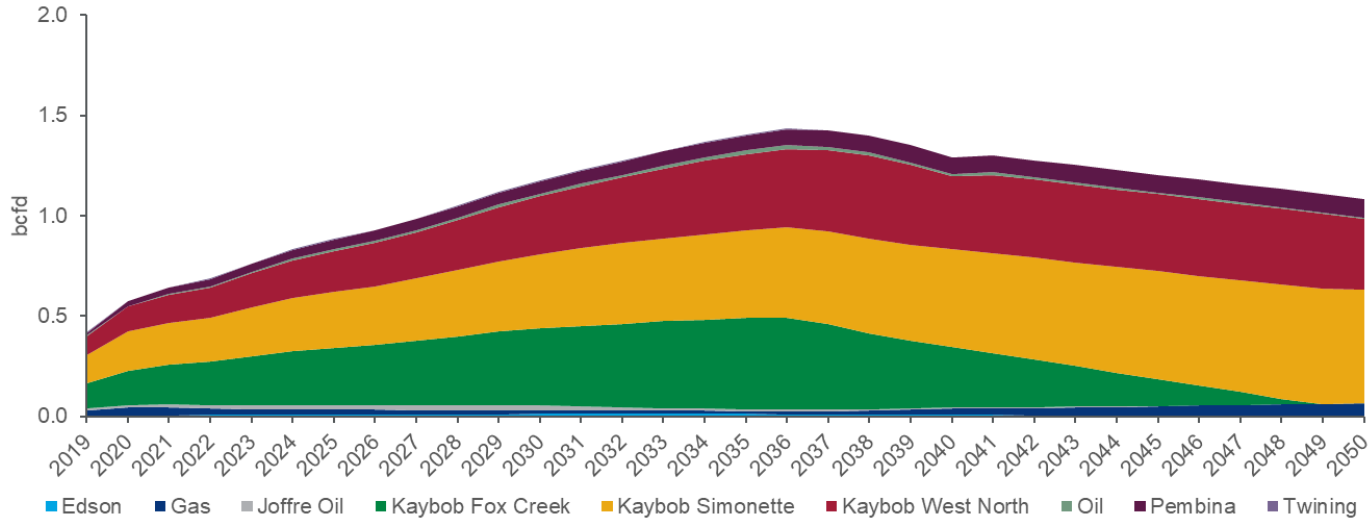
Located in central Alberta, the Duvernay's heterogeneous geology causes well performance, liquids content, and costs to vary drastically across sub-plays. The Kaybob area, which is comprised of liquid-rich sub-plays, is the core development area in the play. Liquids production drives the development of the play, with significant associated gas produced as operators target condensate production to supply growing oil sands diluent demand proximate to the play's drilling activity.

Figure 5.6: Duvernay Play Map



The Kaybob area consists of three key sub-plays: Fox Creek, Simonette/Waskahigan, and West North. Its production currently accounts for 80% of Duvernay's total gas and NGL production and will remain the main driver for production growth in the long-term. The Duvernay's gas production is expected to peak in 2036 at 1.43 bcfd. Although not as prolific as the Montney play, in a scenario with additional Canadian LNG export demand, the Duvernay would benefit from an additional outlet for gas production as the associated nature of the gas production pushes operators to view the gas as a by-product of condensate production, sending volumes to any available outlet to maintain production of the sought after condensate.

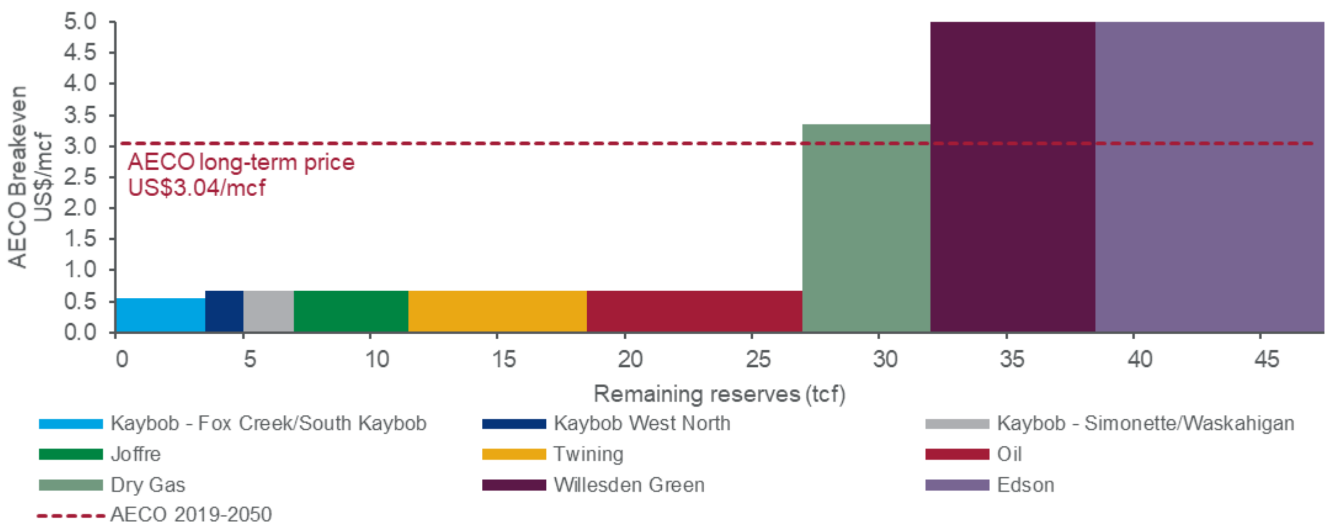
Figure 5.7: Duvernay Gas Production Forecast by Sub-Play



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

The Duvernay has better well economics in the liquid-rich sub-plays clustered at the Kaybob core, with the majority of wellhead breakevens falling under US$0.63/mcf, significantly lower than the long-term AECO price. The eastern sub-plays (Joffre and Twining) also boast low breakevens at US$0.67/mcf, driven by shallow reservoir depths that allow liquids and gas volumes to be produced at lower costs. Drier gas sub-plays are mostly uncommercial under long-term AECO and Henry Hub prices.

Figure 5.8 Duvernay Gas Breakevens and Remaining Reserves by Sub-Play



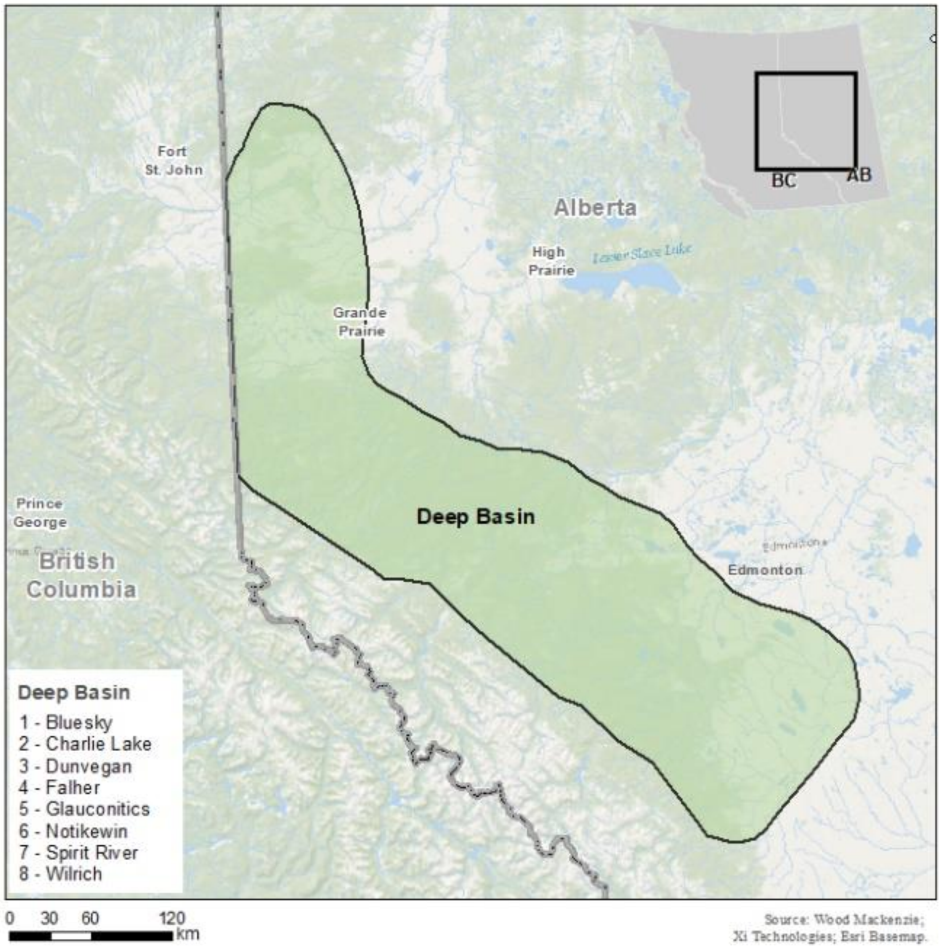
Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

** Long-term AECO price is calculated by taking the average of Wood Mackenzie's GNLQ adjusted base case price forecast from 2019 to 2050*

5.1.3 Deep Basin

The Deep Basin borders the western edge of the WCSB and is one of the deepest formations with a focus on gas with some liquid upside. Despite weak commodity prices, low-cost operators such as Peyto Exploration and Tourmaline Oil have continued to develop the Deep Basin Spirit River Group (Spirit River, Notikewin, Wilrich, and Falher), taking advantage of low well costs.

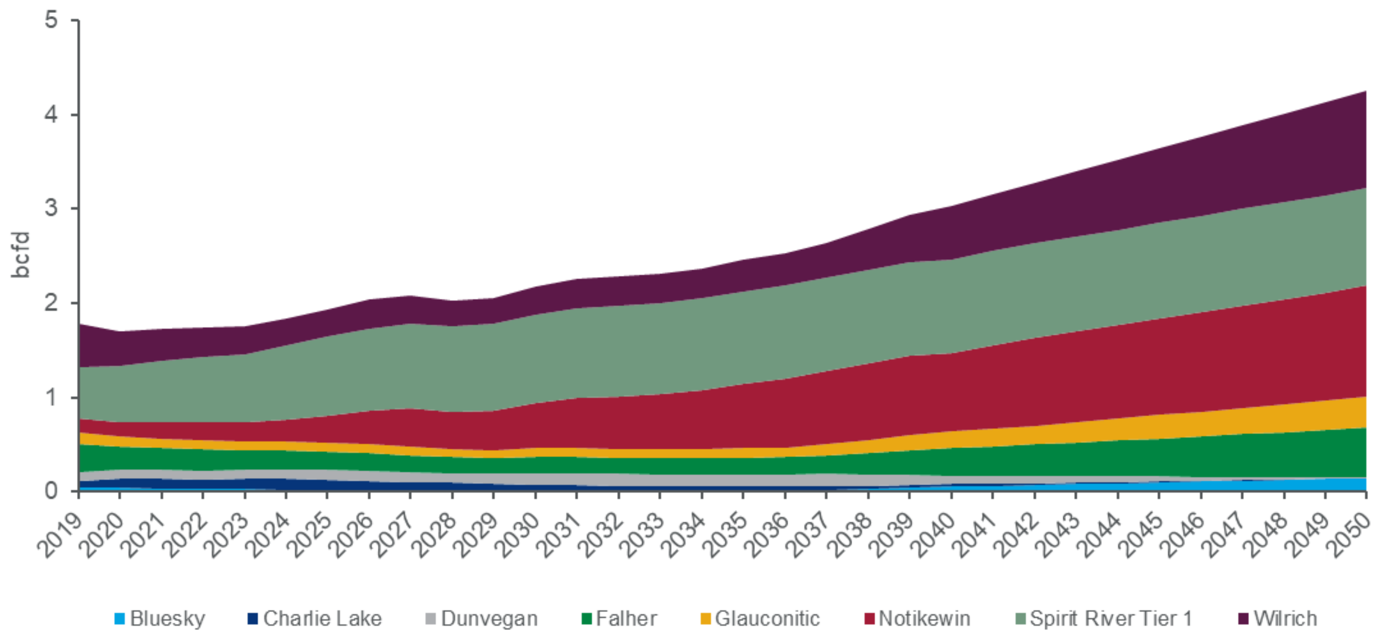
*Figure 5.9: Deep Basin Play Map**



** Because of the geological formation of the Play, Deep Basin sub-plays are layered on top of each other*

Low AECO prices have pressured dry gas development in Deep Basin, leading operators to switch to more liquids-driven plays. However, as gas prices recover, production is also expected to recover in the early 2020s. Long-term growth is steady but slow, which is directly linked to AECO pricing. Most of the growth is seen in the Spirit River, Notikewin and Wilrich sub-plays, contributing 80% of the total production. As Montney gas production depletes post-2036, Deep Basin can provide additional gas supply.

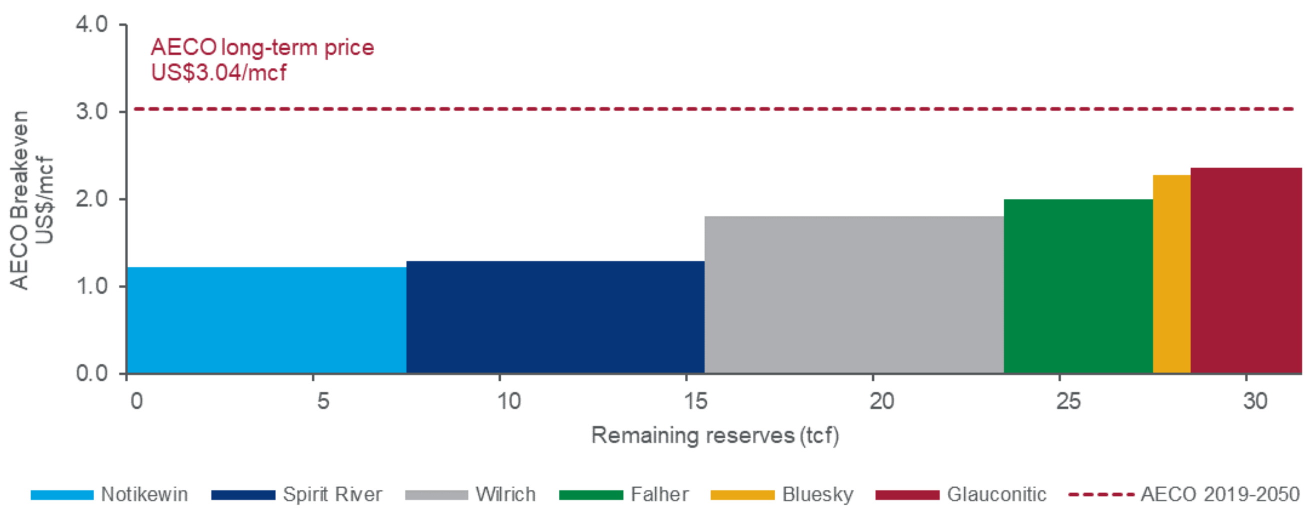
Figure 5.10: Deep Basin Production Forecast by Sub-Play



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

All Deep Basin sub-plays are economic under the long-term AECO price, as high estimated ultimate recovery ("EUR") offset high upstream costs despite being heavily gas-weighted sub-plays. The Spirit River group of sub-plays is expected to lead play development, providing up to 27 tcf of gas reserves at an average of US$1.58/mcf wellhead breakeven. Charlie Lake and Dunvegan have AECO breakevens of US$0/mcf because of high liquid content.

Figure 5.11: Deep Basin Gas Breakeven and Remaining Reserves by Sub-Play



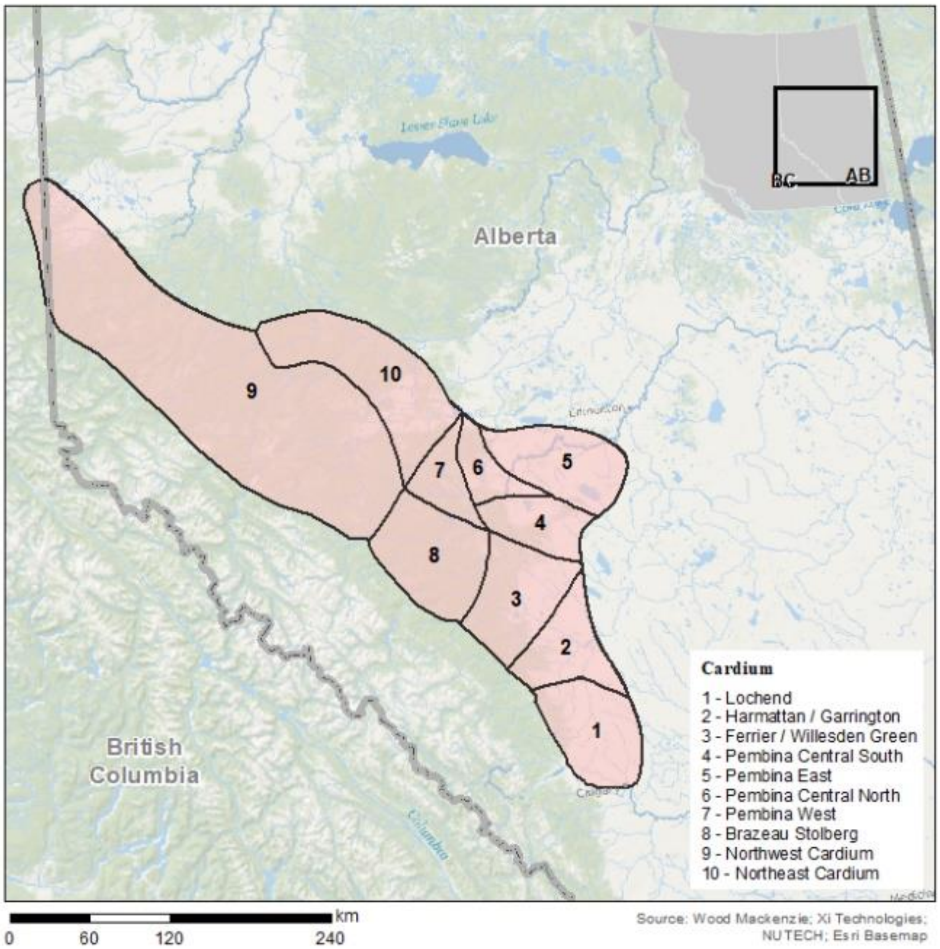
Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

** Long-term AECO price is calculated by taking the average of Wood Mackenzie's GNLQ adjusted base case price forecast from 2019 to 2050*
*** Charlie Lake and Dunvegan are indicative for display purposes; these sub-plays are liquids driven with AECO breakevens of US$0/mcf*

5.1.4 Cardium

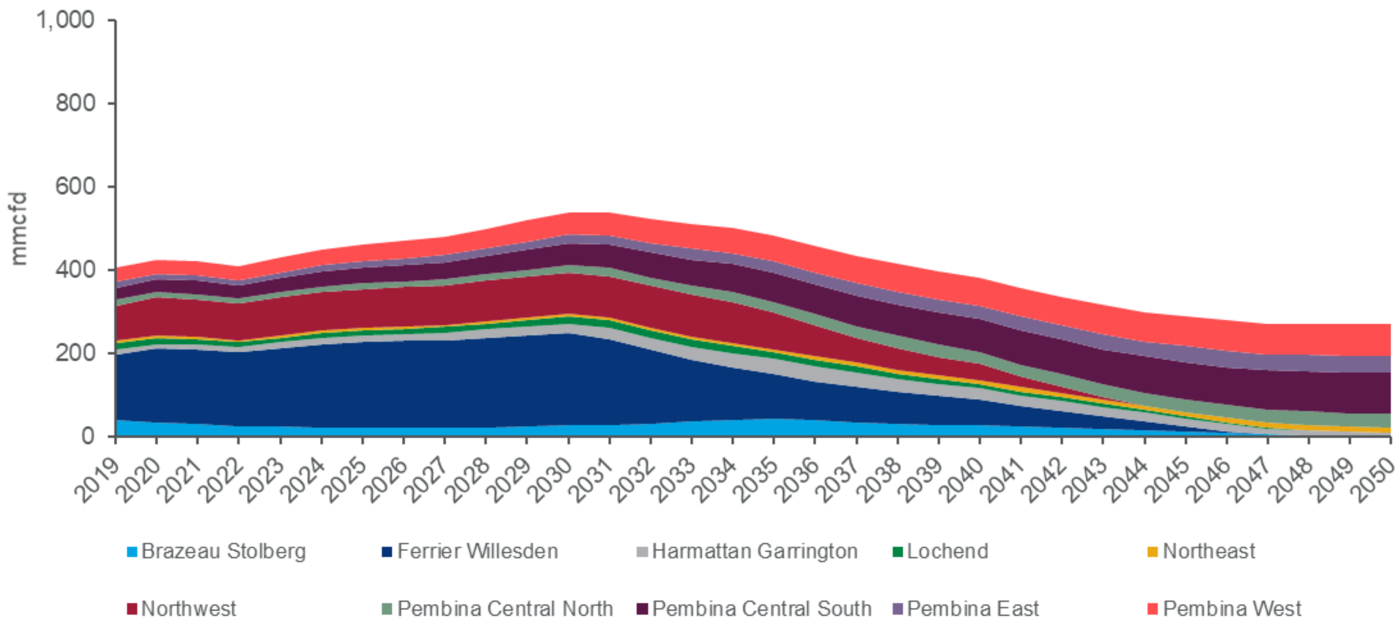
The Cardium is one of the shallower and more oil-prone horizons in region. Conventional oil production began over 50 years ago before peaking in the 1970s at over 150,000 b/d with over 17,000 conventional wells drilled. Technology advancements have unlocked more areas for development in addition to the legacy Pembina sub-plays. In 2010, horizontal drilling surpassed conventional drilling and despite the recent slowdown, stronger oil prices will result in an increase in horizontal drilling activity, unlocking more unconventional resources.

Figure 5.12: Cardium Play Map



Gas production in the Cardium is mainly associated gas, and production steeply increased with the advancement in unconventional drilling from 2010 to 2015 and is expected to grow modestly as operators focus on oil-weighted drilling as oil prices increase. Gas production is forecasted to peak at 537 mmcfd in 2031, with most of the growth attributed to the Ferrier Willesden sub-play.

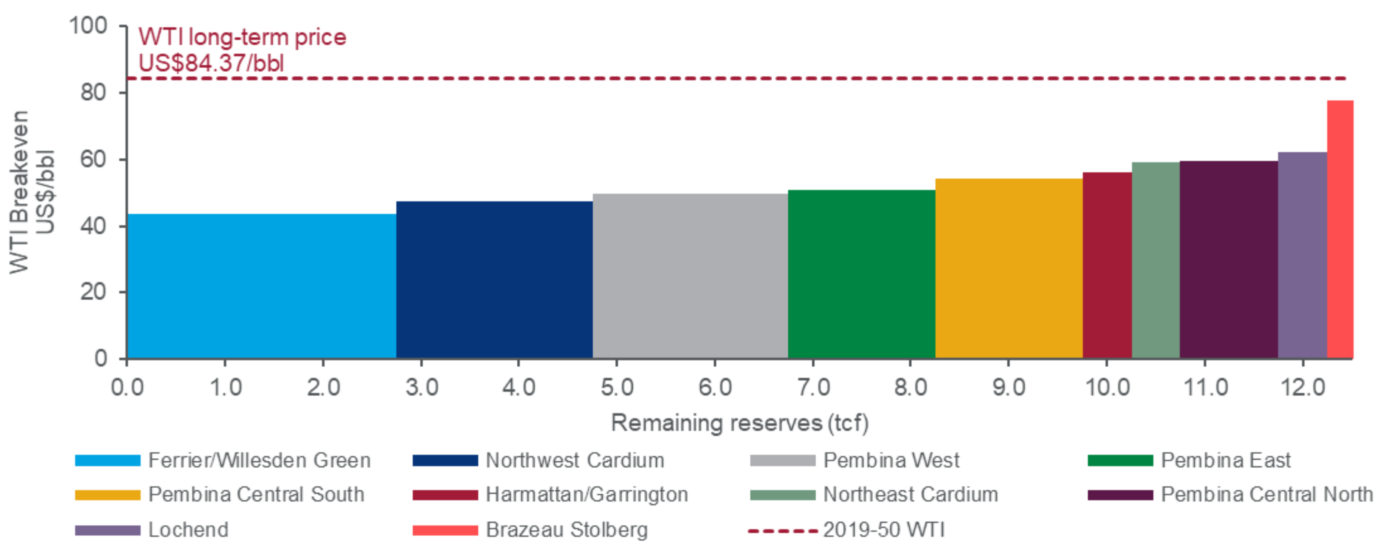
Figure 5.13: Cardium Production Forecast by Sub-Play



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

All Cardium sub-plays are economic under a WTI long-term price of US$84.96/bbl, with operators targeting production at the key tight oil sub-plays, namely Ferrier Willesden, Northwest Cardium, and the Pembina core. These sub-plays produce the lowest wellhead breakevens in the play, as the oil-weighted production and shallow reservoir depth drive improved IRRs and a low cost of production. However, the Cardium possesses the lowest amount of recoverable gas reserves in the WCSB (relative to the plays profiled in this Report), making it less attractive in comparison to other WCSB liquid-rich plays, such as the Montney and Duvernay.

Figure 5.14: Cardium Gas Breakeven and Remaining Reserves by Sub-Play



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

** Long-term WTI price is calculated by taking the average of Wood Mackenzie's GNLQ adjusted base case price forecast from 2019 to 2050*

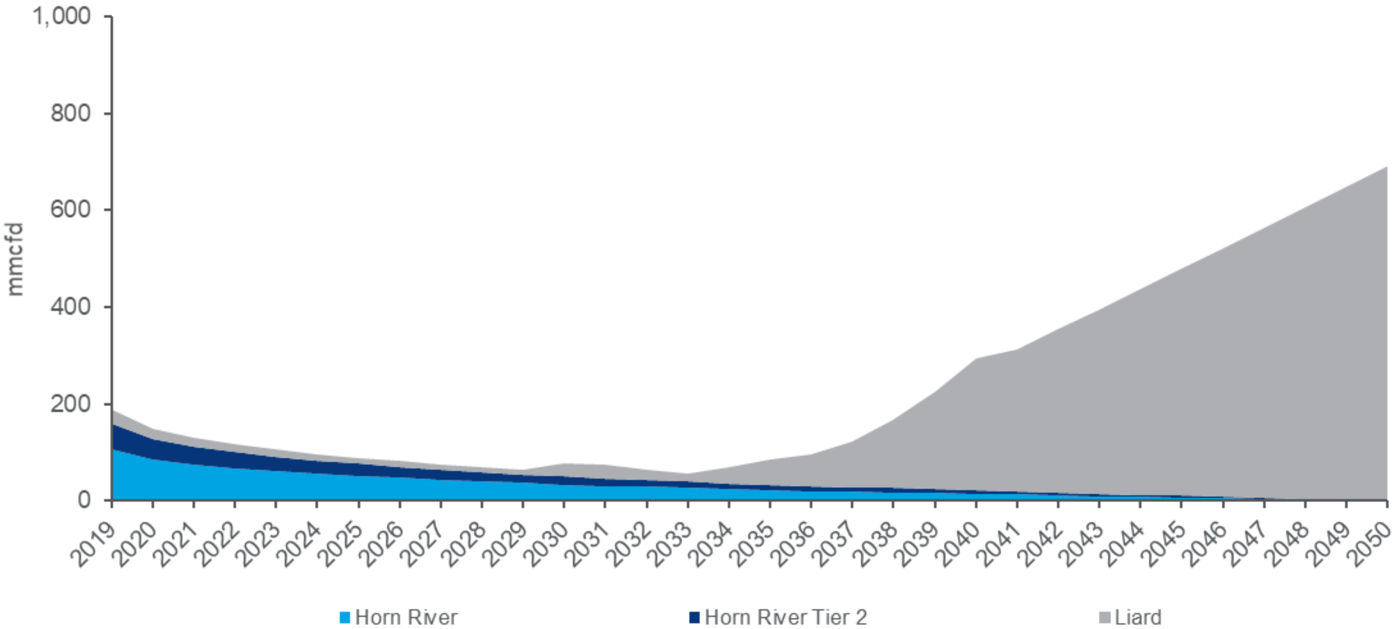
5.1.5 Liard / Horn River

The Horn River play is located in the north-eastern part of BC. Its remote location and challenging operating conditions have restricted field development and production in the region. The high CO_2 content, dry gas composition of the play and the geographic distance to markets put Horn River at a commercial disadvantage against other WCSB plays (Montney, Duvernay, Deep Basin), particularly under low AECO gas price conditions.

Figure 5.15: Liard / Horn River Play Map

Drilling activity in the Horn River has come to a halt since 2014, and Wood Mackenzie does not expect activity to return under the current pricing environment. Chevron drilled 5 wells in the Liard, originally slated for Chevron's Kitimat gas processing plant before an industry shift to cheaper Montney gas. The key challenge for the Liard and Horn River is the limited takeaway capacity to egress due to its remote location. There are significant gas resources in the play, but additional infrastructure development is essential to bring activity back to the region.

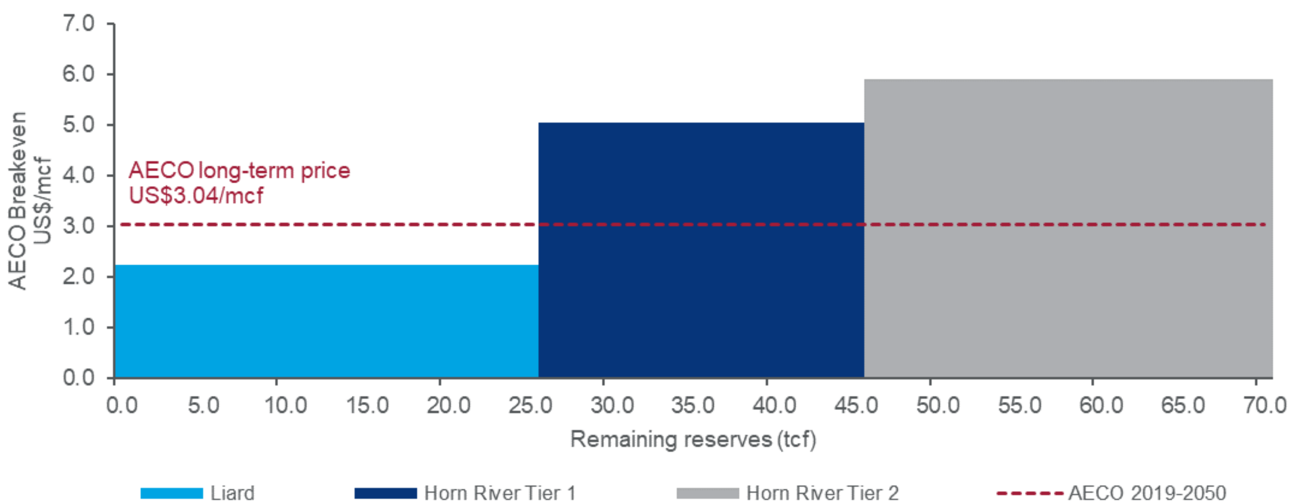
Figure 5.16: Liard / Horn River Production Forecast by Sub-Play



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

The Liard play is economic at AECO long-term price despite sharing a similar geographic location as Horn River. Compared to Horn River, the high dry gas yields and potential reserves, as well as low CO_2 content, set Liard at a better position for attracting future investment with improved AECO prices. Liard production is also expected to displace declining Montney production starting in the late 2030s.

Figure 5.17: Liard/Horn River Gas Breakeven and Remaining Reserves by Sub-Play



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

** Long-term AECO price is calculated by taking the average of Wood Mackenzie's GNLQ adjusted base case price forecast from 2019 to 2050*

6. Canadian Demand Outlook

Wood Mackenzie's forecast of natural gas demand in Canada is fully integrated with other primary energy demand at both a national and global level and extends out to 2050. The demand outlook is broken down into key sectors including: oil sands, other industrial, power, LDC, LNG exports, gas pipeline exports and others (pipeline fuel, transport, etc). An abundance of reliable and economic supply enables steadily growing gas demand, which is expected to grow at 1.8% per annum throughout the forecast period.

The aggressive supply growth profile has caused infrastructure constraints, driving wide basis[2] price differentials at Canadian hubs relative to the key US gas price marker, Henry Hub. Demand for WCSB gas will mirror production growth, with approximately 12 bcfd of growth projected from 2019 to 2050 with most of the growth driven by LNG exports, expected to increase by 8.8 bcfd by 2050. Industrial and oil sands deliver consistent demand growth domestically, however, piped exports to the US, a current driver of WCSB gas demand, have been facing increased competition from low cost US Northeast Marcellus and Utica gas supply, reducing the requirement of Canadian gas to supply the US over time. However, infrastructure developers can be assured that ample gas will be available to meet growing Canadian domestic and LNG export demand as alleviating infrastructure constraints strengthens AECO prices long term.

6.1 Canadian Demand by Sector

In Wood Mackenzie's demand optimization model, seven main demand sectors are identified:

Oil Sands - Industrial

Oil sands is critical to oil supply growth and natural gas feedstock plays an essential role as it is widely used for generating steam for in-situ oil production, heating water to separate bitumen from sand in oil sands mining and creating steam in upgrading to produce the hydrogen that converts bitumen into synthetic crude oil. As Canadian oil sands production continues to increase gradually in the WM base case, from 3 mmbbld in 2019 to 3.6 mmbbld through 2040, supported by significant resources of 49 to 160 billion barrels with breakevens estimated by Wood Mackenzie in the $36/bbl to $68/bbl WTI equivalent range, natural gas demand to serve oil sands operations will grow proportionally. By 2050, 4.4 bcfd of gas will be needed to support oil sands operations, which accounts for 16% of total demand. With egress capacity a key focus for the near term, additional oil sands production growth beyond WM base case will be dependent on new build pipeline egress and rail economics for to allow for the development of currently sub-commercial resources as further exit capacity out of the basin will alleviate price differential weakness and entice economic development of these reserves.

Other Industrial

Other industrial demand beyond oil sands operations will continue to be a main driver for domestic demand growth. Gas demand use by the petrochemical industry is expected to increase by 1.6% per annum throughout the forecast period largely due to the abundance of cheap gas feedstock and incentives that are being advanced such as the two Petrochemicals Diversification Programs currently in place in Alberta to offer incentives to reduce the cost of developing new petrochemical facilities. Other industrial demand, namely in the mining, steel and pulp/paper industries among others, will make up the rest of industrial demand, as operators burning more expensive and carbon intensive fuels (oil derivatives, coal, etc.) switch to natural gas, combined with a forecast of increasing economic activity - total other industrial demand accounts for 14% of the total in the tail end of the forecast period, growing from 2.4 bcfd in 2019 to just under 4 bcfd by 2050.

LDC

Residential and commercial gas demand is primarily related to heating needs and remains relatively flat throughout the forecast period. Modest growth is driven by a population increase and buildout of the pipeline grid to previously unconnected regions

[2] The term 'basis', as used in this report, refers to the difference in pricing of natural gas between any two widely recognized natural gas transaction points such as Henry Hub and the AECO Hub.

converting to natural gas for space and water heating. LDC demand is forecast to grow from 3.2 bcfd in 2019 to 3.5 bcfd by 2050, a 10% increase on 2019 numbers. The advancement of efficiencies (i.e. insulation materials, low energy furnaces), however, will slow demand growth to less than 0.5% per annum post-2035.

Power

Wood Mackenzie forecasts ~6% annual growth in the power generation sector in the next four years as coal to gas switching occurs across the Canadian power sector due to low gas prices and coal plant retirements, namely retirements or conversions of the ageing coal fired power plants in Alberta by 2030, which will result in the shuttering of more than 5.5 GW of coal capacity in favour of more environmentally friendly sources. With a shift away from coal, natural gas fired power will be required to provide baseload electric requirements while providing standby capacity at times when renewable power production is below demand load. Wood Mackenzie forecast power generation demand to grow from 1.7 bcfd in 2019 to 2.2 bcfd by 2050, an increase of 48%. However, continued renewables penetration will offset gains in the future as more baseload generation is dispatched via renewables, growing from 38 TWh in 2020 to 175 TWh through 2050,resulting in a slow and steady decline of gas fired generation growth in the long term, which peaks in 2037 at 135 TWh and then declines to 105 TWh in 2050.

Net Pipe Export

Gas pipeline exports have historically played a crucial role in balancing western Canada gas supply, allowing for upwards of 8 bcfd of natural gas flows into key demand markets across the western, mid-western and Eastern US & Canada. However, exports to eastern Canada and US Lower 48 have partially been displaced by more economic gas production out of Northeast US which is geographically closer to key demand growth areas (US Midwest and Eastern US & Canada), resulting in gas on gas competition across North America, with US L48 production eating into traditional Western Canadian pipeline export markets. Pipeline exports decrease throughout the forecast period, falling from 4.9 bcfd in 2019, to 2.6 bcfd by 2050, a reduction of 46% and equating to 30% of total Canadian demand in 2019 and 9% in 2050. As a result, the additional demand of 1.55 bcfd of LNG exports proposed by the GNLQ project will alleviate the gas on gas competition dynamics from US Lower 48 unconventional gas plays currently facing Canadian producers and will allow for more supply from the WCSB to be dispatched, potentially alleviating downwards price pressure on Western Canadian natural gas hubs.

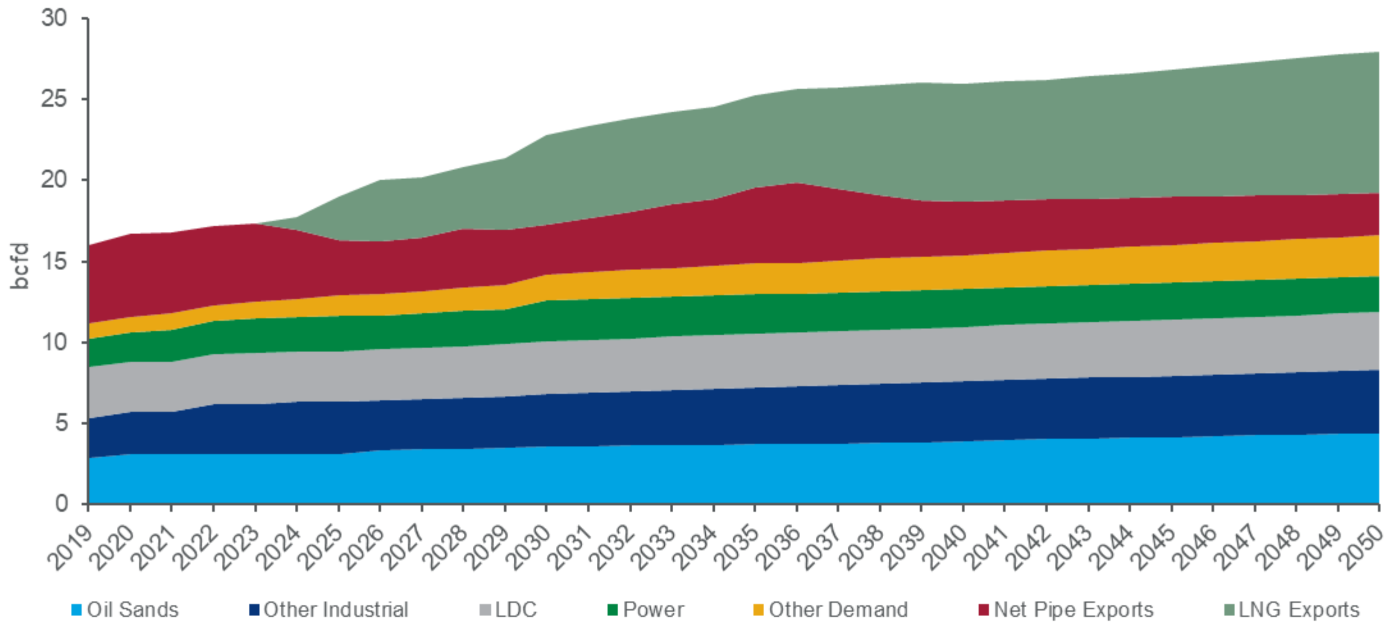
LNG Export

As LNG projects are commissioned post 2024, LNG export demand is forecast to increase rapidly. By 2030, LNG will make up approximately 25% of Canada's total gas demand, or 5.6 Bcfd of total supply, with most projects expected on the West coast of Canada. Wood Mackenzie believes LNG Canada Phase 1, Woodfibre LNG, LNG Canada Phase 2 and two additional generic Western North American projects will be sanctioned in the base case, with LNG exports reaching 8.8 bcfd by 2050. Key factors impacting future LNG flows will be the ability of Canadian developers to secure sufficient off-take commitments from LNG buyers while commitments for adequate, long term transport capacity out of the WCSB (east or west) will also be important to connect land-locked gas supply to waterborne terminals/facilities on either the West or East coasts of Canada. Additionally, environmentally conscious LNG facilities (i.e. electric gas turbine drive, lower emissions compression equipment) will be looked upon favourably as new facilities seek to progress and pass through the new, more stringent regulatory standards put in place in 2019 by the current federal government, which aim to determine the overall net environmental impact of developing large scale LNG export terminals. Ultimately, LNG exports will drive Canadian natural gas demand growth to allow for supply and demand balances to reach equilibrium.

Other Demand

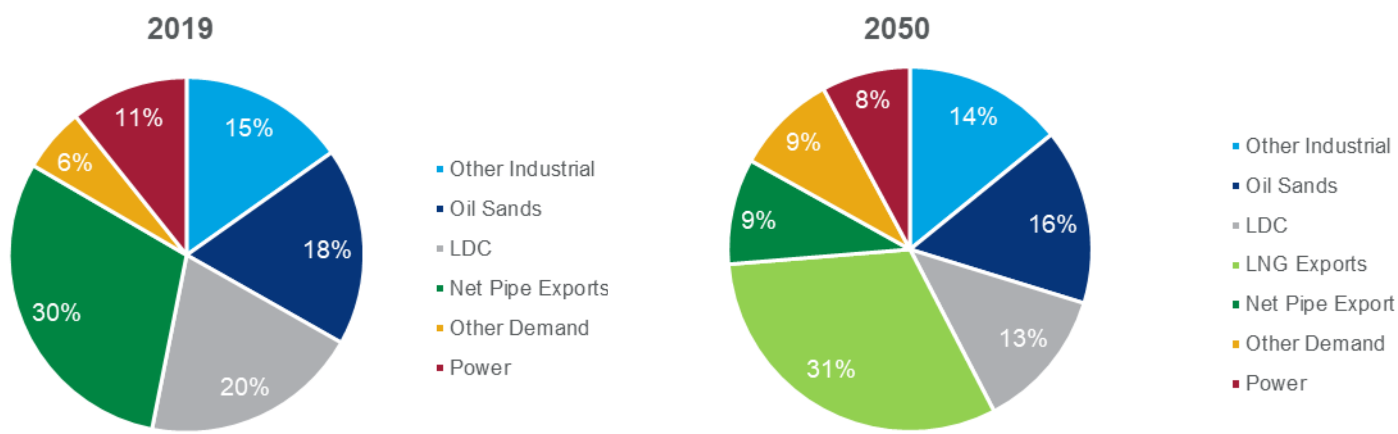
Other demand includes lease, plant, pipe fuel and transportation. As demand, and in turn supply, increase, fuel consumption for the oil and gas sector will increase proportionately. LNG liquefaction process fuel will drive consumption growth of other demand at a more rapid pace post 2024 due to LNG projects coming online and contributing a larger share of the demand balance. Wood Mackenzie forecasts other demand to grow from 0.9 bcfd in 2019, reaching 2.5 bcfd by 2050, an increase of 170% on 2019 levels.

Figure 6.1: Canadian Demand Forecast by Sector



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

Figure 6.2: Canada Gas Demand Mix 2019 vs 2050

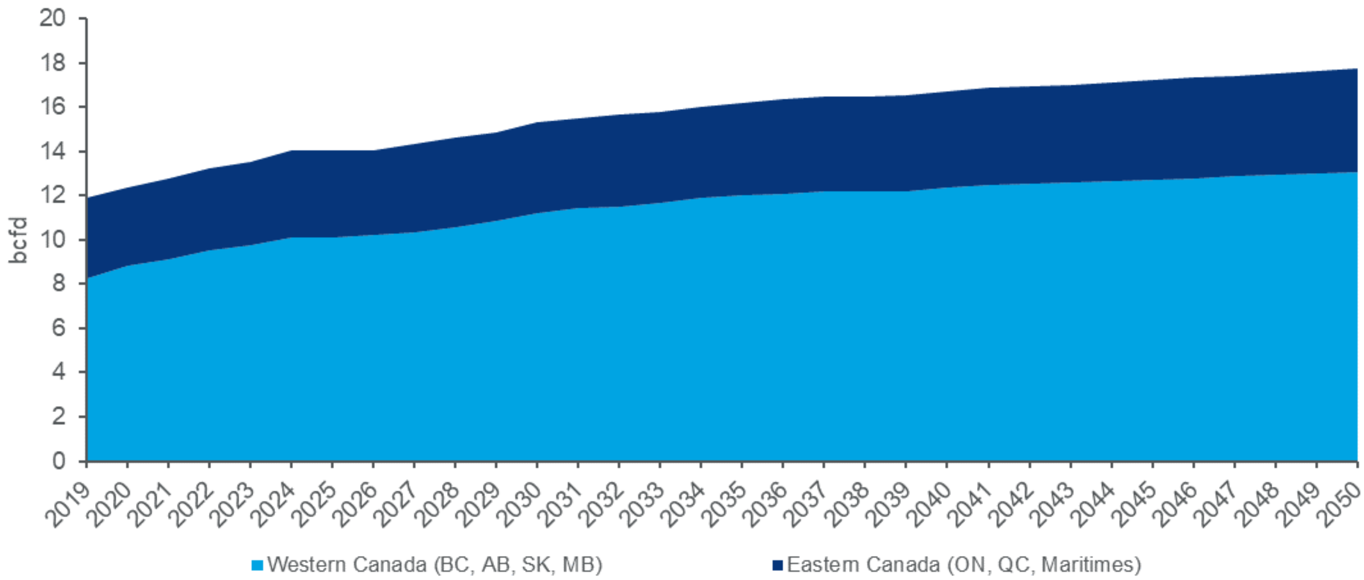


Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

6.2 Canadian Domestic Demand by Region

Although most of the Canadian population resides in eastern Canada, the bulk of the Canadian natural gas demand driven by industry (oil sands), and proximity to cheap supply comes from Alberta and British Columbia making up 70% of the total demand. Alberta is Canada's largest demand sink with a strong industrial sector and oil sands production require significant volumes of natural gas to allow the crude oil to be produced, whether for Steam Assisted Gravity Drainage (SAGD)[3] purposes or for mining extraction. Demand in western Canada is forecasted to grow from 8.3 bfcd in 2019 to 13 bcfd in 2050, up 58%. Gas demand for power generation continues to grow in the West through 2034 reaching 2.1 bcfd though begins to decline post 2034 as the renewables push strengthens, and gas demand begins to decline by ~1% on a CAGR basis through 2050. Residential and commercial demand post marginal gains through the forecast period in the West, though the growth is forecast to plateau in 2037 at 1.3 bcfd as efficiencies in buildings begin to have an impact, arresting any further significant gains.

Figure 6.3: Canada Gas Demand by Region, 2019-2050



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

In Eastern Canada overall demand growth will be much lower at 29%, reaching 4.7 bcfd by 2050, up from 3.6 bcfd in 2019, with marginal impacts to Canadian natural gas balances less than half those from the West. Similar to the West, demand is led by industrial applications, with demand forecast to grow from 1.1 bcfd in 2019 to 1.4 bcfd by 2050, increasing approximately 1% on a CAGR basis. Power generation demand from natural gas in forecast to grow slightly, reaching 0.4 bcfd by 2050, up from 0.3 bcfd in 2019. Residential and commercial demand also follow similar impacts as that of the West reaching 2.1 bcfd by 2050, up from 1.8 bcfd in 2019.

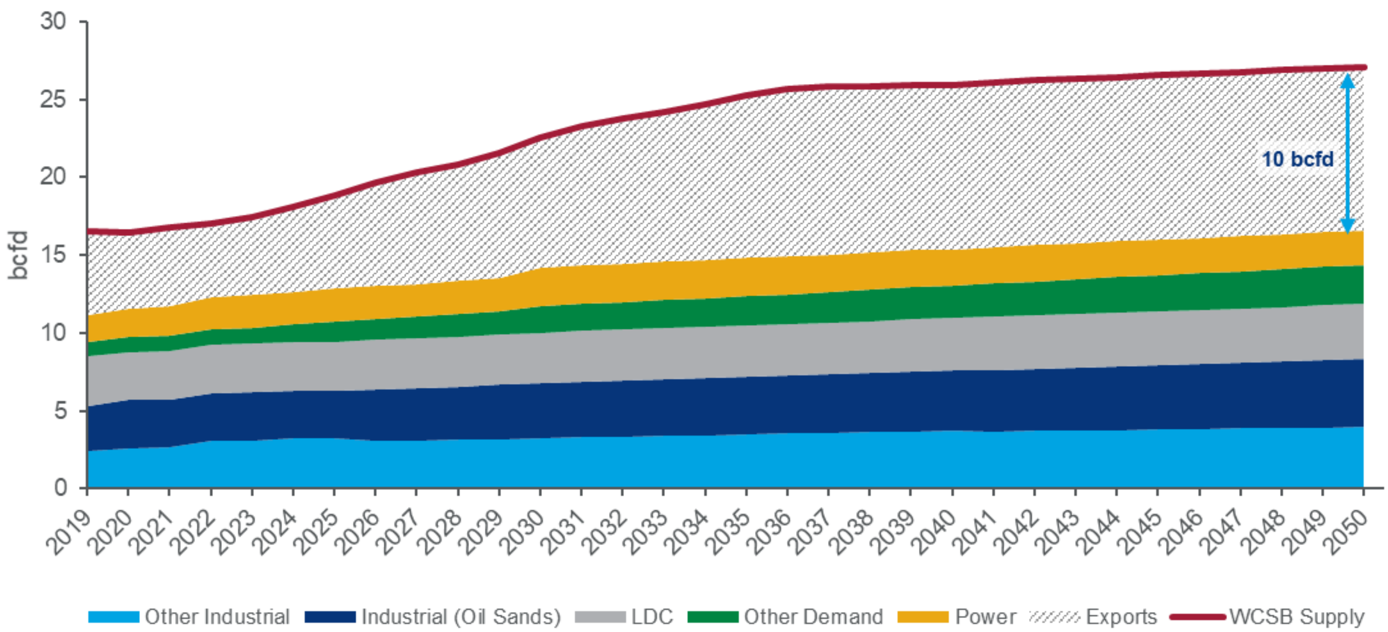
[3] Steam Assisted Gravity Drainage (SAGD) - oil sands extraction technique used where the overburden is too great to extract economically using mining techniques. The technique involves the injection of high pressure, high temperature steam into one well (injector) of a two well pair configuration, increasing the reservoir and bitumen temperature to a viscosity where the oil can then move to the surface on its own, via a second well (producer).

7. Canadian Supply & Demand Balances

7.1 Forecast Supply & Demand Balances

Short term demand growth and infrastructure constraints lead to stagnating pipeline exports, though as TC energy NGTL system maintenance is completed, more export capacity is unlocked and as LNG Canada reaches commercial operations, exports are forecast to rebound. In the mid-term, the Canadian gas supply market will continue to expand in size, adding 8.7 bcfd (53%) of new supply by 2036. Supply growth slows down significantly after 2036 as only an additional 1.8 bcfd will be added by 2050, due to limited demand growth on the demand side and eroding ex-WCSB pipeline exports through the tail end of the forecast period Domestic gas demand growth has always lagged supply and with an expectation of continued advances in technology and increasing adaptation of renewables, domestic demand growth is expected to stay modest. Exports will remain a key focus for operators in the WCSB – LNG and gas pipeline exports to the rest of Canada and the US Lower 48 will be critical for balancing growing production and unlocking further WCSB supply.

Figure 7.1: Canada Gas Supply and Demand Balance



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

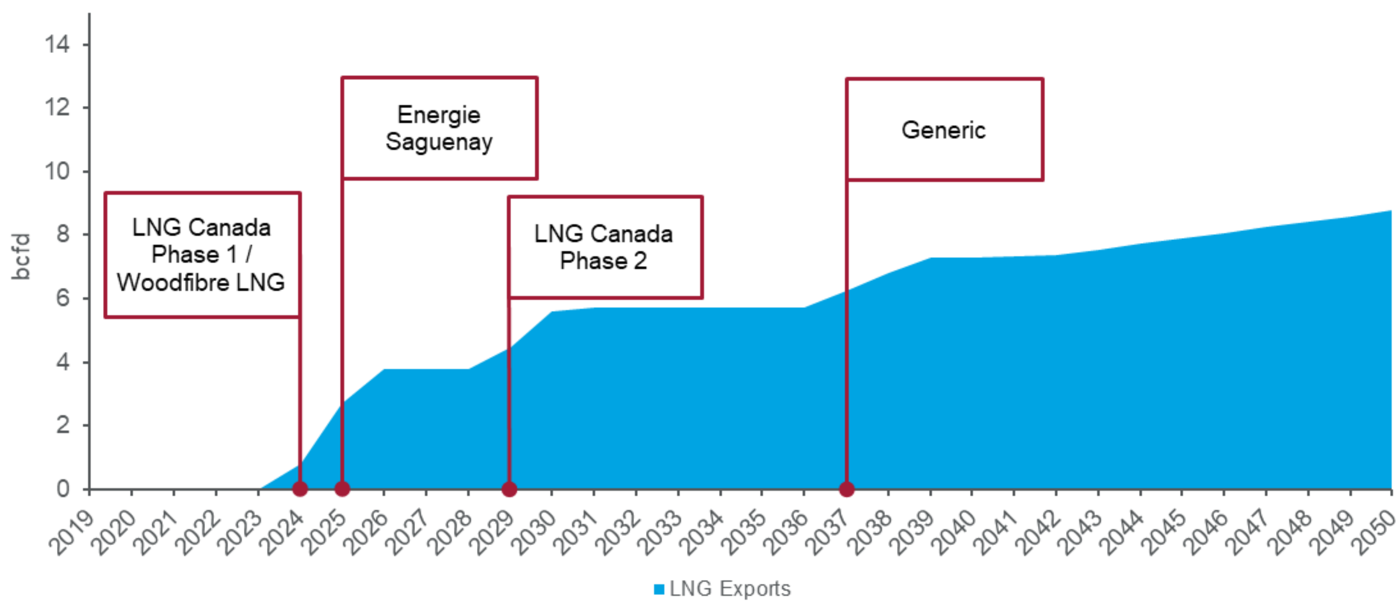
7.2 LNG Exports Outlook

LNG exports represent the single largest source of demand growth for Canadian natural gas, forecasted to rise from zero LNG export volume in 2019 to 5.6 bcfd in 2030 and 8.8 bcfd in 2050. Wood Mackenzie's forecast assumes projects come online with the expected operation start dates outlined below:

Table 7.1: Canada LNG Project Summary

Project	Capacity (mmtpa)	Expected Operation Start Date
Woodfibre LNG	2.1	2024
LNG Canada Phase 1	14.0	2024
Énergie Saguenay	11.0	2025
LNG Canada Phase 2	14.0	2029
Generic	10.0	2037

Figure 7.2: Canada LNG Export Outlook



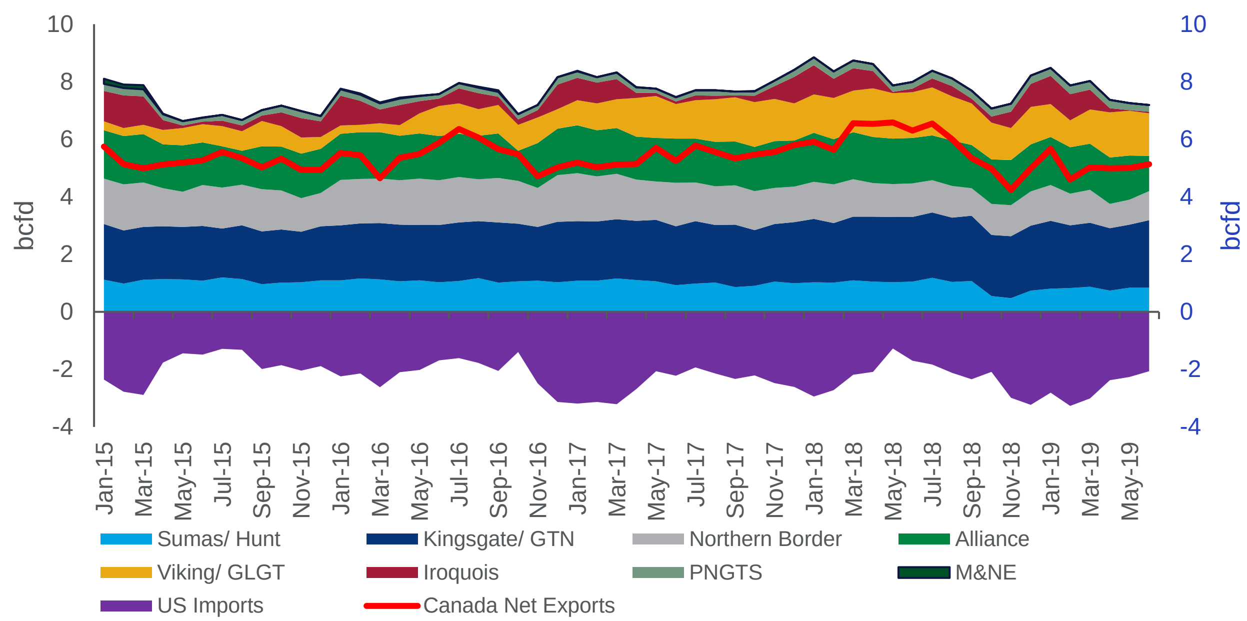
Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

Currently, only LNG Canada Phase 1 has achieved FID, and is aiming to take FID on Phase 2 before flows from Phase 1 commence. Woodfibre LNG is expected to FID later in 2020, though the exact timing of this project and future projects carried in the adjusted base case may shift due to a variety of factors.

7.3 Gas Pipeline Exports Outlook

Canada has traditionally relied on pipeline exports to the US L48 market to balance abundant, low cost natural gas reserves and production, with several gas pipelines connecting the vast resources in the WCSB to US L48 demand regions. Historic Canadian natural gas exports have primarily targeted the US West Coast, US Midwest and some Northeast US demand markets, primarily via interconnections to William's Northwest Pipeline, TC Energy's Gas Transmission Northwest, Pembina & Enbridge's Alliance and TC Energy Northern Border, with some volumes moving into the US northeast via export gas pipelines connected to the Mainline system, namely Portland Natural Gas, Iroquois Pipeline and Maritimes & Northeast Pipeline . However, as the US has grown its own natural gas supply in recent years, natural gas from competing basins in the US L48, namely the Rockies and the Northeast has been slowly pushing into traditional Canadian gas export target markets in the US, while also targeting markets in Eastern Canada. This phenomenon will slowly change the Canadian natural gas market supply and demand dynamic, resulting in slowly declining pipeline natural gas exports to markets in the Eastern Canada and the US Lower 48 over the long-term forecast period.

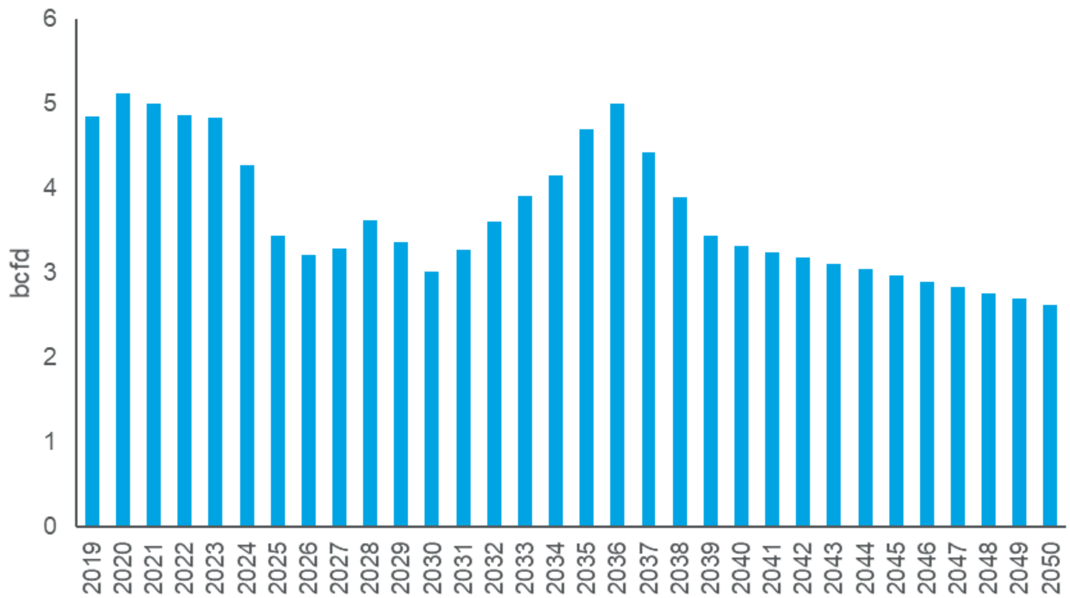
Figure 7.3: Historic Canadian Export/Import Pipeline Flow Balances



Source: Wood Mackenzie, CER, Energy Velocity

As growing competition from L48 gas plays pushes into traditional Canadian export markets in the US in the future, coupled with growing LNG exports, Wood Mackenzie believes net pipeline natural gas exports from Canada will decline slowly in the long term from current levels. Net pipe exports are forecast to remain close to 5 bcfd in the near term, though as LNG Canada completes construction and ramps up, net pipeline natural gas exports should decline to around 3 bcfd in the 2024-2032 timeframe, before experiencing a slight recovery as solid WCSB supply growth outpaces domestic and LNG export demand through the mid-2030s. Post-2038, net pipe exports are forecast to resume a declining trajectory as further competition from US natural gas supply basins flows northward, while additional LNG export demand is unlocked, allowing for more WCSB production to make its way into the waterborne market.

Figure 7.4: Canadian Forecast Net Pipe Exports



Source: Wood Mackenzie H1 2019 Adjusted Base Case

7.4 Reserves Cases Factoring in Export Figures

Canada has abundant natural gas resources as advances in techniques to develop shale gas and tight gas formations through horizontal drilling, hydraulic fracturing, and multi-well pad drilling have supported surging marketable resource estimates. Canadian marketable resources refer to natural gas that is in a marketable condition, after the removal of impurities and after accounting for any volumes used to fuel surface facilities. Marketable resources are recoverable using existing technologies, based on geological information, but much of the drilling necessary to produce the natural gas has not yet been performed.

One of the most comprehensive studies of Canadian shale resources was released by Canadian Association of Petroleum Producers (CAPP). CAPP estimates Canadian marketable gas resources to be 1,220 trillion cubic feet ("Tcf") according to their year-end 2017 figures. Of 1,220 Tcf, 358 Tcf is conventional and the remaining 862 Tcf is unconventional gas including coal-bed methane, shale and tight gas. Compared to US technically recoverable reserves that are estimated to be 2,459 Tcf, Canadian gas reserves compared to domestic demand is substantial.

Table 7.2: US and Canada Marketable and Technically Recoverable Gas Resources

	US and Canada Gas Resources (Tcf)*	
	US	**Canada**
Conventional	979	358
Unconventional	1480	862
Total	2459	1220

*Canadian Association of Petroleum Producers estimate.

Table 7.3 illustrates the Canadian gas resource life under different demand assumptions (details of the domestic demand and LNG export forecasts are discussed in Section 5 and Section 6.2). Scenarios estimate potential gas resource life by comparing Canada's marketable natural gas resource estimates relative to its estimated 2018 natural gas demand, plus scenarios of assumed exports to account for the Project, the Project plus Canadian LNG export projects currently under construction, and the Project, plus projects currently under construction, and projects that currently are under Probable, Possible and Speculative status.

A summary of relevant resource estimates for Canada appears below in Table 7.3.

Table 7.3: Gas Resource Life (to supply domestic demand plus pipeline exports)

	Canada	
	Tcf	**Years**
Marketable Resource*	1220	
2018 Demand**	6.0	205
2018 Demand + GNLQ + Under Construction**	7.8	157
2018 Demand + GNLQ + Under Construction + Probable + Possible + Speculative**	15.8	77

*Canadian Association of Petroleum Producers estimate.
**Wood Mackenzie North America Gas Service estimate. 2018 demand refers to the demand for domestic gas consumption in Canada, plus net gas transmission line shipments out of Canada.

The first and most conservative scenario estimates the potential gas resource life by considering 2018 natural gas demand only (including net piped exports to the US) and shows that there are 205 years' worth of natural gas under the current level of recoverable resources in Canada.

In a second scenario, after including the export quantity sought by the Project and other LNG projects that are currently under construction into consideration, the resource life remains in excess of 157 years. The third scenario that includes all the LNG liquefaction projects that are under consideration in Canada, including the Project, those under construction, those which are probable, possible and speculative, which would account for 27 bcfd of LNG export demand, still results in 77 years' worth of natural gas supply under current reserves estimates. However, this scenario is highly unlikely based on Wood Mackenzie assumptions.

Across the second and third scenarios which include the Project, there is still an estimated 77 to 157 years' worth of gas supply, which indicates there is little risk to supply availability needed to meet Canadian demand in the foreseeable future.

Error! Reference source not found. depicts LNG liquefaction projects sourcing gas from Canada that have applied or are in the process of applying for a natural gas export licence with the CER which were considered in the different reserve life scenarios. Descriptions of the different project status can be found in Appendix C. To note, despite LNG projects receiving authorization to export natural gas from Canada, having applied for an export licence or are in the process of applying for a natural gas export licence, does not mean that specific project will go ahead to the next stage of development or even may not get built. Many factors determine a specific projects chances of success and whether these projects will go ahead will be dependent upon many variables which are challenging to predict.

Table 7.4: Liquefaction Project Details

Status	Project	Location	Net Export Quantity (bcfd)
Project	Energie Saguenay	East Canada	1.56
U/C	LNG Canada	West Canada	3.48
Probable	Woodfibre	West Canada	0.28
Possible	Kitimat LNG	West Canada	2.73
Possible	Jordan Cove LNG	West Canada	1.55
Possible	Goldboro LNG	East Canada	1.40
Speculative	Triton LNG	West Canada	0.32
Speculative	Stewart LNG	West Canada	3.99
Speculative	Kitsault LNG	West Canada	2.71
Speculative	Bear Head LNG	East Canada	0.25
Speculative	Cedar LNG	West Canada	0.83
Speculative	New Times Energy	West Canada	1.61
Speculative	Rockyview Resources LNG	West Canada	2.63
Speculative	Delta LNG	West Canada	0.40
Speculative	Orca LNG	West Canada	3.20

Source: Wood Mackenzie

7.5 GNLQ Adjusted Base Case vs WM Base Case and Impacts to Upstream Supply

GNLQ will seek to source 1.64 bcfd of feedgas from the WCSB to supply LNG export volumes for the Project, though not all of this gas will be marginal production, above the WM Base Case, dispatched from Western Canada. This is due to the shifting North American supply and demand and subsequently, natural gas flow dynamics.

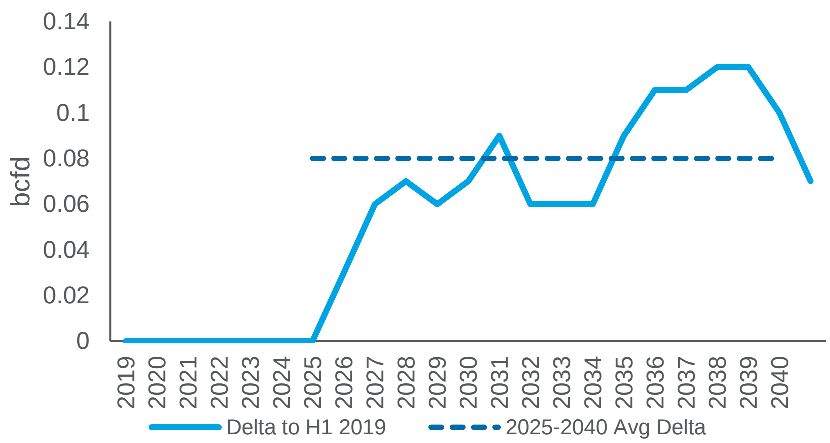
Under the Wood Mackenzie proprietary dispatch model, when modelling the adjusted base case, over the 2025-2040 timeframe, only 0.08 Bcfd of marginal upstream supply was required from new sources above the WM H1 2019 Base Case due to the pull from GNLQ required project feedgas volumes. This is a result of reduced export pipeline flows from the WCSB primarily to markets in the US L48, namely the Midwest and East, with minor East Canada market impacts. These marginal pipeline export volumes balancing WCSB natural gas production must price competitively relative to US natural gas supplies to move into traditional export demand markets.

Effectively, due to the additional demand pull requiring supplies from the WCSB as a result of the Project, a portion of export pipeline supply heading to the US L48 markets and markets in Eastern Canada under the H1 2019 Base Case is redirected to supply the forecast natural gas requirements for feed gas, and only results in an incremental WCSB supply increase above the WM H1 2019 base case of 0.08 Bcfd.

Regarding the displacement of WCSB pipeline exports, the flows which will be impacted the greatest in the Adjusted Base Case versus the WM H1 2019 Base Case, are pipeline natural gas exports to the US Midwest (with a minimal impact to Eastern Canada flows), primarily on the Northern Border pipeline, Viking pipeline and Great Lakes Gas Transmission pipelines as these are the paths with the greatest cost to market. Due to the additional demand created as a result of the Energie Saguenay project and the slightly higher impact to natural gas prices at AECO, the resulting AECO price and costs of pipeline transport to get to the US Midwest market (including some Eastern Canada flows) will effectively be more than additional supplies from the US Northeast and other US production regions, using existing pipeline infrastructure from the Marcellus/Utica or Permian/MidCon to get to the Chicago area. Additionally, some incremental production flowing North from the Mid continent & Permian will also dispatch at a lower cost and fill the gap resulting from lower WCSB imports, thus satisfying the demand in the Midwest and Eastern Canada regions in lieu of WCSB pipeline gas imports.

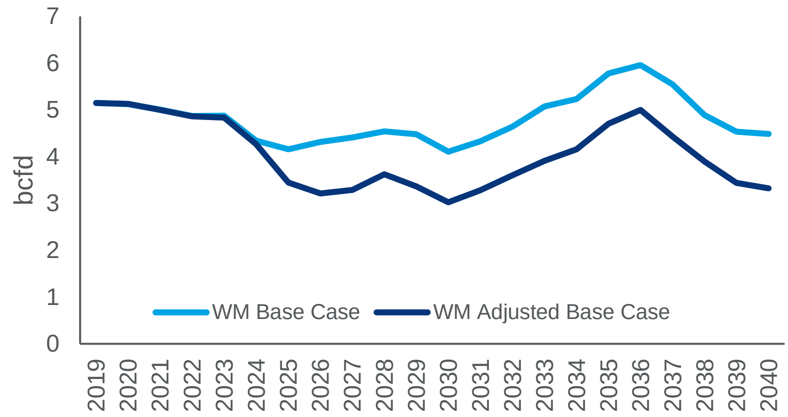
The balance of required supply to meet domestic US & Canadian forecast demand in the Adjusted Base Case is slated to be sourced from the US L48, primarily from NE US volumes from the Marcellus & Utica plays, which are in near proximity to Midwest US and Eastern Canadian demand, offer low breakeven costs of supply and have recently targeted infrastructure capacity increases and reversal to bring natural gas to demand markets in the US Midwest and Eastern Canada.

Figure 7.5: WCSB Upstream Supply Delta, WM Base Case vs Adjusted Base Case, bcfd



Source: Wood Mackenzie

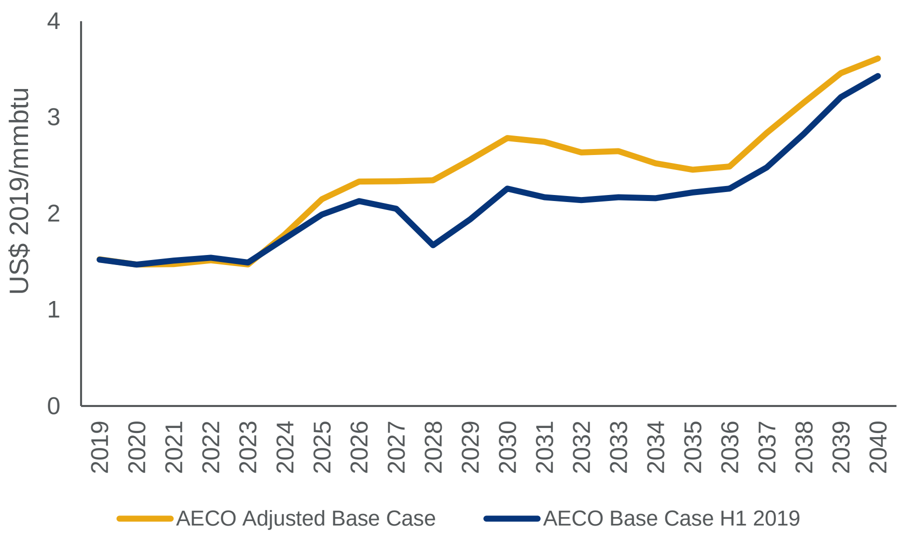
Figure 7.6: WCSB Net Pipe Exports, WM Base Case vs Adjusted Base Case, bcfd



Source: Wood Mackenzie

Additionally, due to the small increase in WCSB gas supply over the forecast timeframe which dispatched slightly more expensive natural gas, the impact to prices was also marginal at an average price increase of US$0.35/mmbtu (2019 real terms) over the 2025-2040 timeframe.

Figure 7.7: AECO Price Impacts, WM Base Case vs Adjusted Base Case, US$/mmbtu (2019 Real)



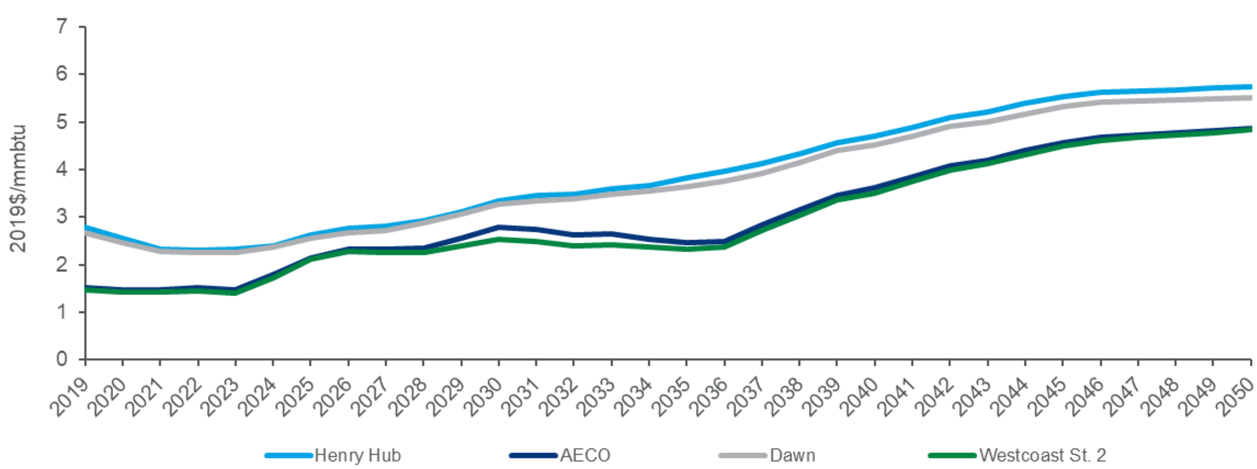
Source: Wood Mackenzie

8. North American Price Outlook

Gas prices are determined by a combination of the cost of production, gathering & processing, competing fuels, gas on gas competition, pipeline capacity availability, and cost to transport gas from supply sources to major demand centres across North America. The Henry Hub pricing point is the reference for North American gas prices as it is the official delivery point for NYMEX futures and spot market gas trading, with other regional price hubs trading at either a premium or discount to the Henry Hub price marker. Wood Mackenzie has focused on the four most important regional price points impacting Canadian natural gas supply - each price hub represents major Canadian supply and/or demand points and other important price hubs affecting Canadian natural gas balances:

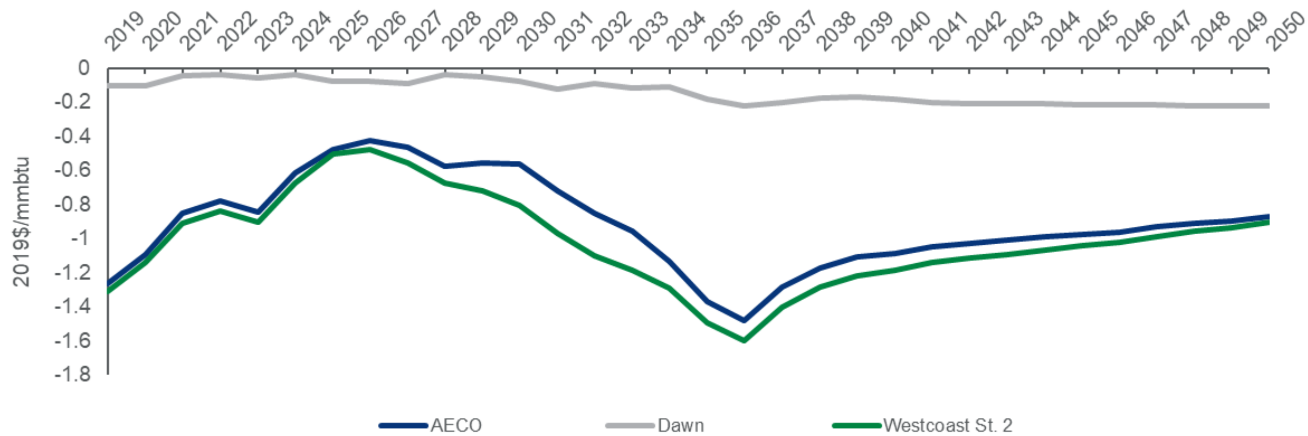
- **AECO**: AECO is a virtual gas trading hub for all gas volumes flowing through the Alberta NOVA Inventory Transfer (NIT) and is the main pricing index for Canadian WCSB natural gas production (equivalent to Henry Hub for US gas production) and is an extremely liquid point. Physical volumes traded in 2019 amounted to 12.7 bcfd, in aggregate.
- **Station 2**: Located in Northeast British Colombia, Station 2 is one of the key points of Enbridge's (previously Spectra) Westcoast pipeline. It is a virtual transfer point for market participants wishing to trade gas where the T-North line joins the Fort St. John line and flows into the T-South line past Station 2, carrying natural gas to markets in Southern British Colombia, including an interconnection point to the US Pacific Northwest.
- **Dawn:** Located in Southwest Ontario, Dawn is adjacent to major industrial complexes and large natural gas storage pools in the Sarnia area. It remains one of the most liquid trading hubs in North America as market participants from Western Canada, Eastern Canada and the US actively trade and transact around the Dawn index. It also interconnects with pipelines supplying gas from key US supply basins, such as the Marcellus, Utica, and Rockies.

Figure 8.1: Gas Price Forecast on Selected North America Hubs (2019 – 2050)



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

Figure 8.2: Gas Price Outlook on Basis Differential to Henry Hub (2019 – 2050)



Source: Wood Mackenzie H1 2019 adjusted GNLQ base case

Henry Hub prices average $2.46/mmbtu through 2023. Vast volumes of low to zero cost associated gas supply, primarily driven by Permian tight oil production, flood the market pressuring the price downwards. These volumes are supplemented by economic dry gas resources from the Haynesville play and Northeast US (Marcellus and Utica plays), with significant resources with sub-$2.50/mmbtu breakevens resulting in a moderately depressed Henry Hub price in the short-term.

Moving forward, second wave of US LNG facilities coming online unlocks the global market potential that underpins LNG export demand growth. This much anticipated market expansion increases Henry Hub prices above $3.00/mmbtu by 2029. Resilient North American LNG export growth continues to increase the call on dry gas volumes, pushing Henry Hub prices to eclipse the $5.00/mmbtu mark by 2042, and reaching $5.74/mmbtu by 2050.

Pricing differentials to Henry Hub

AECO and Station 2 are flooded with associated gas volumes produced by WCSB liquids-rich fields through 2023. However, Western Canadian demand growth is not enough to balance the available supply, whereas available takeaway capacity on the NGTL system at West Gate is insufficient to egress the WCSB supply growth to the Eastern Canadian and US demand markets. Additionally, increasing cheap gas supply from the US, combined with high transportation costs, reduce the attractiveness of WCSB gas for US pipeline export. As a result, AECO and Station 2 prices are expected to be discounted relative to Henry Hub by $0.97/mmbtu and $1.02/mmbtu through 2023, respectively. Dawn experiences similar price dynamics to Henry Hub as associated gas volumes from the WCSB and Lower 48, as well as a relatively flat Northeast US supply cost stack pressure Dawn price downward relative to Henry Hub prices, averaging $2.39/mmbtu between 2019 and 2023.

LNG Canada, which is forecast to come online in 2024, will significantly change Canadian gas market dynamics by creating a large new demand centre to debottleneck the expected WCSB supply surplus. This results in AECO and Station 2 prices reaching over $2.00/mmbtu by 2025 and initially reducing differentials to Henry Hub to $0.60-0.80/mmbtu. Nonetheless, AECO and Station 2 price gains are potentially offset by expiring long-term fixed price (LTFP) contracts for the TC Mainline pipeline. The TC Mainline holds a critical role in unlocking the Eastern Canada and US demand markets. Without set LTFP renewals currently carried in the WM adjusted base case, AECO and Station 2 prices are expected to move downwards to the <$2.00/mmbtu range in the 2026 to 2028 timeframe to allow for additional export volumes to flow out of the WCSB basin. Beyond 2028, AECO and Station 2 price points are expected to recover with LNG Canada Phase 2 coming online to alleviate supply constraints. However, the second wave of US LNG facilities increase Henry Hub prices above $3.00/mmbtu by 2029 and coupled with abundant lower cost supply out of the WCSB, these factors drive up the basis differentials of AECO and Station 2 post 2029.

AECO and Station 2 are expected to appreciate steadily as additional LNG projects come online post 2037. Likewise, we foresee growing demand for US natural gas exports as further US LNG projects enter service in 2038 and core areas of US dry gas supply are slowly depleting post-2035, pulling more WCSB supply to the US Pacific Northwest. Similar to the US, WCSB producers will be required to shift the production focus to higher-cost gas extraction as core, lower cost drilling locations are depleted, which tightens AECO & Station 2 basis spread to Henry Hub in the long-term. Dawn follows Henry Hub closely through 2050 reaching $5.51/mmbtu by 2050, though is pressured under Henry Hub towards the back end of the forecast as lower cost US Northeast gas continues to push into Chicago/Sarnia physical natural gas infrastructure and key market hub.

Leveraging our integrated pricing models, Wood Mackenzie has forecast these four selected price hubs as well as Henry Hub through 2050. **Error! Reference source not found.** illustrates the price movement between 2019 – 2050 with the following section outlining significant price trends and key drivers for each price point at short-term, mid-term, and long-term horizons.

Short-term Price Outlook (2019 – 2023)

Henry Hub prices remain depressed, averaging $2.46/mmbtu through 2023. Vast volumes of low to zero cost associated gas supply, primarily driven by Permian tight oil production, flood the market pressuring the price downwards. These volumes are supplemented by economic dry gas resources from the Haynesville play and Northeast US (Marcellus and Utica plays), with significant resources with sub-$2.50/mmbtu breakevens resulting in a moderately depressed Henry Hub price in the short-term.

AECO and Station 2 are also flooded with associated gas volumes produced by WCSB liquids-rich fields. However, Western Canada demand growth is stagnant, whereas available takeaway capacity is insufficient to egress the WCSB supply growth to the Eastern Canadian and US demand markets. Additionally, increasing cheap gas supply from the US Northeast and associated gas from the Bakken play, combined with high transportation costs, reduce WCSB attractiveness for US export. As a result, AECO and Station 2 prices are expected to remain heavily discounted relative to Henry Hub by $0.97/mmbtu and $1.02/mmbtu, respectively

Dawn experiences similar price dynamics to Henry Hub as associated gas volumes from the WCSB, Rockies, and Mid-Continent, as well as a relatively flat Northeast US supply stack pressure Dawn prices downward on a similar trajectory as Henry Hub prices, averaging $2.39/mmbtu between 2019 and 2023. On the contrary, a lower production outlook that results in the US Northeast region remaining over-piped improves DSP basis price differentials in the short-term, with prices averaging $2.28/mmbtu.

Mid-term Price Outlook (2024 – 2035)

LNG Canada, which comes online in 2024, will significantly change Canadian gas market dynamics by creating new demand centres to debottleneck the WCSB gas supply surplus. Wood Mackenzie expects a portion of existing gas production from LNG Canada partners (Shell 40%, PETRONAS 25%, PetroChina 15%, Mitsubishi 15% and KOGAS 5%) to be re-directed to supply the LNG facility away from current sales into AECO and Station 2, while a majority of feed gas will be supplied by new drill production. This results in AECO and Station 2 prices reaching $2.00/mmbtu by 2025 and initially reducing differentials to Henry Hub to $0.60-0.80/mmbtu. Nonetheless, AECO and Station 2 price gains would be partially offset by expiring long-term fixed price (LTFP) contracts for the TC Energy Mainline , which hold a critical role in unlocking Eastern Canada and US demand markets. Without set LTFP renewals, we expect AECO and Station 2 prices to move below the $2.00/mmbtu range.

Beyond 2028, AECO and Station 2 price points are expected to recover with LNG Canada Phase 2 coming online to alleviate supply constraints. However, we also expect a second wave of US LNG facilities to come online, unlocking the global market potential that underpins LNG export demand growth. This much anticipated market expansion increases Henry Hub prices above $3.00/mmbtu by 2029, driving up the basis differentials to AECO and Station 2 post-2029.

Although debottlenecked in the mid-term, US Northeast production continues to grow into available capacity towards 2028 and new long-haul capacity will only be needed post-2030 as DSP basis widens to above $0.50/mmbtu post-2028. With environmental and public opposition as well as cost overruns on current projects, we believe the next round of pipeline development will be high cost and with a higher degree of difficulty. US Northeast production is forecast to continue growing through 2035 as sufficient economic resource exist and, coupled with higher costs of future capacity buildout in the US Northeast, WM believes the discount of DSP to Henry Hub will continue to widen gradually during this period.

Long-term Price Outlook (2036 – 2050)

Resilient North American LNG export growth continues to increase the call on dry gas volumes, pushing Henry Hub prices to eclipse the $5.00/mmbtu mark by 2042. Western Canadian prices (AECO and Station 2) are expected to appreciate steadily as additional LNG projects come online post-2037. Likewise, we foresee growing demand for US natural gas exports as further US LNG projects enter service in 2038 and core areas of US dry gas supply are slowly depleted post-2035, pulling more WCSB supply to the US Pacific Northwest. As a result, WCSB producers will be required to shift the production focus to higher-cost gas extraction, namely the Liard and/or the Horn River, helping to replace WCSB's other declining supply sources, which tightens AECO & Station 2 basis price differentials to Henry Hub in the long-term. Additionally, gas pipeline costs ex-WCSB to major US and Eastern Canadian demand centers are forecast to continually decrease due to the shrinking rate base of the TC Energy Canadian Mainline, which is forecast to also have a tightening effect on basis over the long term. Dawn follows Henry Hub closely in the long-term while DSP basis continues to widen, again driven by increasing production which will require costlier long-haul pipe capacity buildout.

9. Risks to Supply & Demand Outlooks

9.1 Risks to Supply

9.1.1 AECO Price Dynamics

Low gas prices pose the largest risk to WCSB production. Recently, AECO has traded at sub-$1.50/mmbtu, resulting in negative producer cash flows in some circumstances and lower IRRs. Consequently, producers have tended to reduce capital spending programs, which will reduce activity in WCSB plays. In a sustained low, long-term AECO price environment, fewer drilled wells and slower field development could gradually reduce the WCSB production outlook.

While high AECO prices encourage producers to increase capital investments leading to WCSB production growth, it poses a separate risk to the Project's supply volume as a portion of it will likely be indexed to AECO prices. Thus, increasing AECO prices lead to a higher sourcing cost, impacting project economics. However, LNG demand markets (i.e. Asia, Europe) are expected to remain robust, support the projects economics, while the availability of WCSB supply at relatively low costs is expected to limit the amount of AECO price upside throughout the forecast period.

9.1.2 Premature Decline of Liquids-Rich Gas Production

Liquids, which are comprised of condensates and light oil, are critical components that are required as a diluent by the Canadian oil sands industry to enable the flow of heavy oil down pipelines. As oil price has increased in the last three years, so too has oil sands production. Increasing liquids requirements drive producers to target operations in liquid-rich plays, resulting in ample low-cost associated gas volumes. A future rise in the oil price could incentivize producers to set more aggressive drilling programs in the liquid-rich plays. However, there are only a finite amount of economic WSCB associated gas reserves and extensive liquids production short-term could exhaust these reserves sooner than the adjusted base case forecast, potentially accelerating the onset of, and increasing the pace at which overall WCSB production declines.

9.1.3 Less Field Development from Acquired Acreage Positions

WCSB plays are saturated by operators aiming to reap high production outcomes, leveraging supportive geological characteristics and attractive well economics. However, sustained low AECO prices could result in smaller producers, who have been key drivers of future growth plans, having difficulty executing their capital expenditure programs. Larger operators could see this as an opportunity to acquire acreage positions from the struggling small operators to consolidate their geographic footprint for economies of scale. Should the larger operators acquire the smaller parties, they could exercise a strategy which maintains production to fill existing capacity without the need to grow production. This could result in a lower supply outlook as operators could slow down new well drilling activity to maintain production at levels not exceeding gas processing capacity, which in turn potentially could exacerbate delays in supply development across the WCSB.

9.1.4 US Lower 48 Supply Competition

The resurgence of shale gas production in the Marcellus/Utica and Bakken poses competition to WCSB exports. Both Marcellus/Utica and Bakken gas volumes benefit from low transportation costs as they are located adjacent to US demand markets (i.e. Midwest and Northeast). Meanwhile, WCSB production generally faces higher transportation costs, resulting in WCSB supply becoming less attractive to supply US markets. Technology advancement driving outperformance of productivity and efficiency improvements could also improve Marcellus/Utica and Bakken breakevens. In this situation, WCSB piped exports to the US could be more limited due to the competitive environment, consequently pressuring regional gas prices and delaying WCSB supply growth.

9.1.5 Other Regulatory and Environmental Risks

Uncertainties around regulations and environmental sanctions could impact investments in the WCSB, putting production at risk of delay or suspension. Below are some regulatory and environmental challenges that potentially limit WCSB capability to supply the Project:

- Opposition could potentially delay WCSB growth. In the past, opposition groups have successfully delayed gas-related projects. Effective communication and collaboration is key to mitigate this risk. Under our adjusted base case assumptions, Wood Mackenzie anticipates that opposition will not unduly impact WCSB development. The Alberta government has previously imposed temporary production curtailments to resolve crude takeaway congestions and prolonged low commodity prices. The curtailment is expected to end by 2020, with the cut-off limit to be increased between now and 2020. With gas prices having faced a similar crash, there is a possibility for a similar curtailment to be assessed for gas production. However, with additional takeaway capacity and LNG exports coming online, regional gas prices should recover in the short-term, which minimizes the risk of gas production curtailments being imposed and, even if imposed, we would expect they would be short-lived.
- Carbon-pricing plans, or widely known as a carbon tax, have been implemented in several Canadian provinces and are in the process of being applied at a national level by the Federal government, as an effort to reduce carbon emissions and fossil fuel use. The Greenhouse Gas Pollution Pricing Act (GHGPPA) regulates the minimum price applied to fossil fuel end-users for each Canadian province. Although the recent AB government has taken a strong position against the carbon tax, there is still uncertainty around whether the federal government would impose federal carbon tax starting in January 2020. In contrast, BC is the first province to apply a carbon tax, starting in 2008. Since then, BC has grown its economy even with the presence of carbon taxation. Thus, we do not foresee any significant impact to WCSB production economics from the carbon tax implementation. Furthermore, we expect the carbon tax to foster more gas volumes for LNG exports if domestic demand declines more than expected due to enactment of a Federal carbon tax policy.
- Fracking underpins the majority of WCSB activities, making it susceptible to fracking bans. For instance, the AB government temporarily halted fracking operations in the Duvernay formation last March due to escalating earthquakes reaching up to a 4.4 magnitude. Similarly, the BC government also raised a temporary fracking halt in 2018 following 3.5 – 4.0 magnitude earthquakes, forcing well shutdowns that lasted for 30 days. A fracking halt could delay or suspend WCSB production as it forces producers to shut down wells for an indefinite period. Nonetheless, the economies of British Columbia and Alberta are heavily underpinned by the oil and gas industry, and a fracking ban would severely impact Provincial revenues. Therefore, Wood Mackenzie considers the implementation of an indefinite, all-out fracking ban as a very low probability.

9.2 Risks to Demand

9.2.1 Economic Growth

The recent trade turmoil and slowdown in global economic activity may have an impact on demand growth, both from a global perspective and in Canada. As the global economy is susceptible to trade disputes resulting in additional costs of trading goods and services, this may impact the energy demand required to create, package and ship goods to their destination. A prolonged trade dispute between the two largest global economies (US and China) may result in a slowdown of economic activity and growth, impacting domestic natural gas demand growth to the downside. However, Wood Mackenzie believes that the risk of a prolonged trade dispute to be minimal as the negative consequences of such a scenario far outweigh the benefits of trade wars. In a prolonged trade war case, Canadian LNG exports may be looked upon favourably by Chinese end users of LNG (CNOOC, CNPC, Sinopec, etc.) as a mitigant to US LNG exports, which may result in additional LNG facility buildout above and beyond the WM base case, resulting in higher LNG exports from Canada.

9.2.2 The Push for Emissions Reductions and Carbon Policies

A recent shift in public opinion, both across North America and globally, pushing for more stringent climate change and emissions reductions targets could adversely affect natural gas demand growth in Canada. With carbon taxes already in place in many Canadian jurisdictions and the goal to roll out a federal policy by January of 2020, an increase in costs to the end user of fossil fuelled energy, including natural gas consumers, is expected. Under this scenario, Canadian natural gas consumption growth is expected to be impacted to the downside across the demand sectors. However, under this scenario, less domestic demand will result in additional supply available for the Project, which may result in lower gas sourcing costs, enhancing the Project's competitiveness globally. Additionally, with a significant portion of the energy required to operate the Project coming from hydro-electric sources, the Project has a distinct advantage to other competing projects from a carbon footprint standpoint, which may be well received from a regulatory standpoint.

9.2.3 Other Demand Side Risks

A shift in power generation capacity buildout in favour of renewables (solar, wind, biomass, etc.) is already present in today's power markets, as individuals, companies and nations seek to lower emissions from generating electricity. Should the pace at which developers add renewable power capacity increase above the adjusted base case assumptions, natural gas used to generate electricity could be impacted to the downside. However, since solar and wind capacity are not available at all times of the day/year, natural gas fired generation is forecast to remain the complementary fuel of choice at times of low renewables dispatch to provide reliability for the intermittent nature of renewables.

10. Conclusions

There are abundant gas resources and a strong supply push from the WCSB while domestic demand growth remains modest: Wood Mackenzie believes WCSB gas supplies are more than adequate to support indigenous demand throughout the study period as well as LNG exports. Gas supply growth outperforms domestic demand growth during the forecast period from 2019 to 2050 (10.5 bcfd vs 6.9 bcfd), and with the decrease in pipeline export demand, ~ 8.8 bcfd of supply will be met by LNG exports in 2050. Ample amounts of WCSB gas reserves are economic under the adjusted base case long-term forecasted Henry Hub price, competitive with some of the best basins in the US. With the advances in production and renewable energy technology, we could see larger supply and demand gap in the future that would need to be met by exports.

Western Canada's key AECO trading hub displays strong physical and trading liquidity: The western Canada region has an advantageous position near low-cost associated and non-associated gas production, an actively expanding infrastructure network, and increasing links to demand centres both domestic and export. Trading at the AECO hub is very liquid, and a high level of transparency mitigates risks for traders, producers and end users of Canadian natural gas.

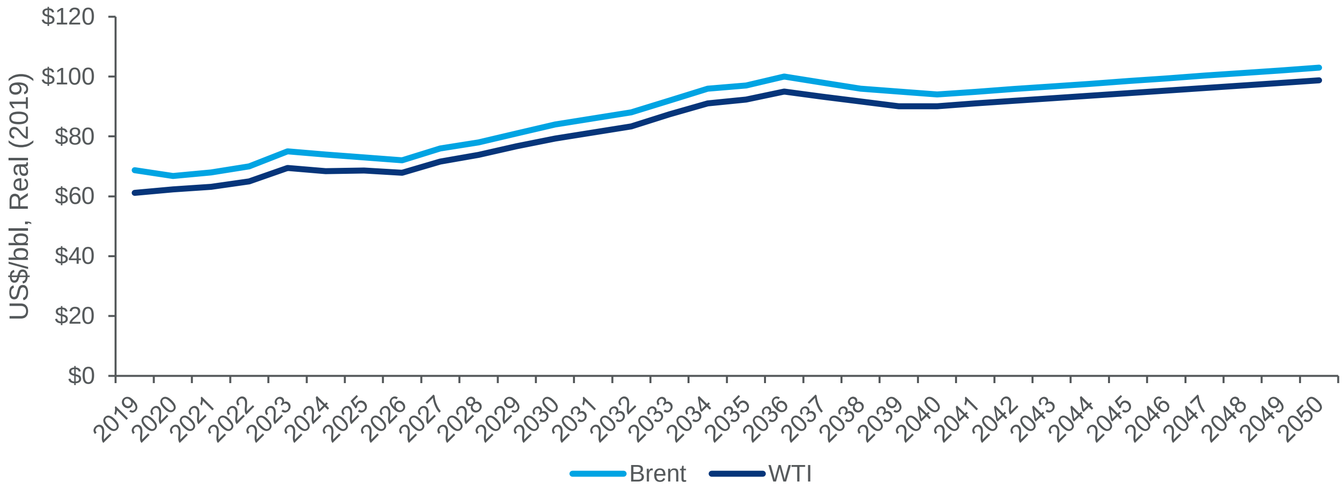
There is a strong need for additional pipeline egress capacity to drive production growth which the Project will provide: The WCSB has been historically dependent on export markets in the US to balance gas production. Growing supply has exacerbated infrastructure constraints and depressed regional prices in the near term. The Gas transmission line and the Project will provide additional connectivity to demand markets globally, incentivizing midstream operators to expand egress capacity out of the WCSB which will in turn stimulate production growth.

Regional market pricing dynamics create opportunities for the Project: The upstream economics and low breakevens in the WCSB play a key role in the Project's positioning. Although Wood Mackenzie anticipates, the Project's gas transmission line transport costs from AECO to the Project's location could be more expensive compared to LNG export projects on the Canadian West Coast due to the greater transport distance, the Project can capitalize on the spread between AECO and global gas prices, its unique location in Quebec reducing overall CAPEX and OPEX, its lower GHG emissions and its access to hydropower while taking advantage of cheaper feedstock costs versus Henry Hub-indexed projects.

11. Appendices

Appendix A – Oil Price Forecast

Figure 11.1: Wood Mackenzie Oil Price Forecast (US$/bbl)



Source: Wood Mackenzie Macro Oils Service Adjusted GNLQ Base Case

Appendix B – Macroeconomics

Table 11.1: GDP Growth on a Constant US Dollar Basis

Year	GDP		Year	GDP	
	US	Canada		US	Canada
2019	2.5%	1.6%	2035	1.8%	1.8%
2020	1.6%	1.3%	2036	1.9%	1.8%
2021	1.4%	1.4%	2037	1.9%	1.8%
2022	1.9%	1.8%	2038	1.8%	1.8%
2023	2.2%	1.6%	2039	1.8%	1.7%
2024	2.1%	1.6%	2040	1.8%	1.7%
2025	2.0%	1.6%	2041	1.8%	1.7%
2026	1.9%	1.5%	2042	1.8%	1.7%
2027	1.9%	1.5%	2043	1.8%	1.7%
2028	1.9%	1.5%	2044	1.8%	1.7%
2029	1.9%	1.6%	2045	1.8%	1.7%
2030	1.9%	1.6%	2046	1.8%	1.7%
2031	1.8%	1.7%	2047	1.8%	1.7%
2032	1.9%	1.7%	2048	1.8%	1.7%
2033	1.9%	1.8%	2049	1.8%	1.7%
2034	1.9%	1.8%	2050	1.8%	1.7%

Table 11.2: Inflation

Year	Inflation		Year	Inflation	
	US	Canada		US	Canada
2019	2.1%	2.2%	2035	2.0%	2.0%
2020	2.1%	2.1%	2036	2.0%	2.0%
2021	2.1%	2.1%	2037	2.0%	2.0%
2022	2.1%	2.1%	2038	2.0%	2.0%
2023	2.0%	2.0%	2039	2.0%	2.0%
2024	2.0%	2.0%	2040	2.0%	2.0%
2025	2.0%	2.0%	2041	2.0%	2.0%
2026	2.0%	2.0%	2042	2.0%	2.0%
2027	2.0%	2.0%	2043	2.0%	2.0%
2028	2.0%	2.0%	2044	2.0%	2.0%
2029	2.0%	2.0%	2045	2.0%	2.0%
2030	2.0%	2.0%	2046	2.0%	2.0%
2031	2.0%	2.0%	2047	2.0%	2.0%
2032	2.0%	2.0%	2048	2.0%	2.0%
2033	2.0%	2.0%	2049	2.0%	2.0%
2034	2.0%	2.0%	2050	2.0%	2.0%

Appendix C – Definitions

Definitions of Wood Mackenzie LNG Supply Project Categories:

Operational: Supply projects which are currently operational.

Under Construction: Supply projects which have taken the Final Investment Decision (FID) and / or are under construction.

Probable: Supply projects which have not yet taken FID, but which in our opinion, are expected to do so within the next 12 months.

Possible: Proposed Supply projects that are named and which are reasonably well defined in terms of participation, structure and underlying gas resource(s), but which are not expected to take FID within the next 12 months. However, if in our opinion, one or more of the major issues or challenges are currently preventing the project from making substantial progress; we classify it as speculative instead.

Speculative: Either, an LNG Supply project that currently lacks any reasonable definition in terms of participants, structure and / or underlying gas resources or, a well-defined proposed Supply project where, in our opinion, one or more major issues or challenges is currently preventing the project from making substantial progress.

Appendix D – Conversion & Currency Exchange

Conversion Rates

Volumes within this report are based on gas at Standard Temperature and Pressure 15˚C (59˚F) and 760 mmHg with a common calorific value of 40 MJ/m^3 (1,074 Btu/scf). This is to enable LNG volumes, indigenous production and piped imports to be compared on a consistent energy basis across the globe. Calorific values are dependent on the specific chemical composition of the gas which varies field by field across the world. LNG tends to have a higher calorific value than conventional indigenous production or gas transmission line gas because of the cryogenic process required to produced LNG – lower dew points and CO_2 contents are required to prevent frost formation in the liquefaction equipment.

Table 11.3: Conversion Rates for Energy

Unit	mmbtu	bcf	mcf	Mcm	GJ
1 mmbtu	1	0.000000962	0.000962	0.0000272	1.0552
1 bcf	1,040,000	1	1000	28.32	1,097,200
1 mcf	1.04	0.001	1	0.0283	1,097
1 Mcm	36.7224	0.0353	35.31	1	38,742
1 GJ	0.9477	0.000000911	0.000911	0.0000258	1

Table 11.4: Conversion Rates for Volumes (Gas / LNG)

Unit	Tonne LNG	mmtpa LNG	Mcm	Mcm/d	Bcf/d
1 tonne LNG =	1	1,000	0.0014	0.0000384	0.00000136
1 mmtpa LNG =	0.001	1	0.000014	3.84×10^{-8}	1.36×10^{-9}
1 Mcm =	712	0.712	1	0.00274	0.00009675
1 mcm/d =	0.73189	0.00073189	365	1	0.03531
1 bcf/d =	0.0258	0.000258	10,336.8	28.32	1

Currency Exchanges

Table 11.5: Wood Mackenzie Annual Exchange Rates from US Dollar

Year	Canadian Dollar (Real 2019)
2019	1.33
2020	1.31
2021	1.28
2022	1.26
2023	1.25
2024	1.25
2025	1.25
2026	1.25
2027	1.25
2028	1.25
2029	1.25
2030	1.25
2031	1.25
2032	1.25
2033	1.25
2034	1.25

Year	Canadian Dollar (Real 2019)
2035	1.25
2036	1.25
2037	1.25
2038	1.25
2039	1.25
2040	1.25
2041	1.25
2042	1.25
2043	1.25
2044	1.25
2045	1.25
2046	1.25
2047	1.25
2048	1.25
2049	1.25
2050	1.25

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