

Gas Processing Management Incorporated (GPMi)

Alberta Gas Supply and Infrastructure Analysis

The Assessment of Gas Supply and Infrastructure as it relates to the development and operation of Natural Gas Fired Power Generation in the Province of Alberta

B, Armstrong, R, Child and T. Joubert
December, 2016

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Section 1 – Introduction

The following report has been commissioned by the Independent System Operator operating as the Alberta Electrical Systems Operator (AESO). The purpose of the report is to assist them in understanding the operation of the Alberta (AB) and Western Canada Natural Gas Systems as they relate to the development and operation of dependable and reliable large scale natural gas fired electrical power generation in AB as a replacement for coal fired power generation and back up to electrical power generated by renewable sources. The Report examines AB, Western Canada as the AB systems are interconnected to those in British Columbia (BC), Saskatchewan (SK) and the United States (US). The US is included as their natural gas systems are interconnected with those in Western Canada through export pipelines and have the potential to impact operations in Canada.

The Study utilizes available public source data to provide a detailed understanding of:

- Natural gas demand, supply and available resource in AB, Western Canada and the US and a comparison of the systems in Western Canada and the US.
- Intra AB Natural Gas Systems, the overall reliability and dependability of those systems and their commercial operations. Where the operation of the system is interconnected with BC and SK, the analysis has been expanded to include Western Canada. The analysis includes natural gas production, gathering and processing, sales gas transportation and storage.
- The potential operation of large scale Natural Gas Fired Power Generation and the factors that will affect the reliability and dependability of that Generation.

Section 2 – Executive Summary

The analysis of the natural gas systems in Western Canada and the integration of large scale natural gas fired electrical power generation concludes that there is substantial natural gas resource, a dependable delivery system and established commercial processes underpinning its operation. However, there are characteristics of the natural gas system that will need to be monitored and managed to ensure future reliability of electricity supply from natural gas fired power generation, especially in regions with a high concentration of such assets. Some potential areas of assessment include:

- Regions such as Lake Wabamun could potentially have a high concentration of natural gas-fired generation that may be dependent upon a limited pipeline infrastructure for fuel supply. As the pipeline infrastructure is expanded to allow for increased natural gas demand for power generation, analysis of planned and forced pipeline outages needs to be completed with potential mitigation plans where significant reliability issues may arise. Such mitigation activities may include redundant pipelines or minimizing the number of electric power generators that are dependent upon a single pipeline.
- The timing to develop additional pipeline infrastructure in fully contracted delivery point regions needs to be reviewed to ensure reliable fuel supply on a timely basis to meet the incremental natural gas demand for electrical power generation.
- The supply of natural gas into the system is relatively inflexible over the short term (i.e., within hours) with fluctuations in demand or supply generally balanced through the use of system line pack and natural gas storage. The system was not originally designed with the capability to respond to large short term fluctuations in natural gas demand that may evolve based on the requirements of electrical power generation (i.e., increased volatility in natural gas demand for electric power generation resulting from changes in renewables electrical production). The generation facilities may need to consider the installation of on-site storage of natural gas or fuel switching capability to ensure fully dependable operation to manage low probability high impact events where natural gas from the system may not be available.
- For increased long-term reliability, natural gas storage facilities within the Alberta system should be assessed (particularly withdrawal capacities) as natural gas fired electrical power generation and renewables generation increase in Alberta.

Additional recommendations as the power and natural gas markets become more integrated include:

1. Natural gas system operators and electric power generation developers work together to ensure that the influx of new natural gas electric power generation does not impact regional system reliability.
2. To ensure reliability of fuel supply, electric power generators should consider high-priority, high-capacity transportation services and storage contracts. These may include on-site storage contracts and facilities.

The following summary provides the high level observations from the following sections:

Western Canadian Natural Gas Overview

- Total Western Canada Natural Gas Demand (including production facility fuel) is expected to increase to 13.4 Bcf/d in 2040 from 9.1 Bcf/d in 2015. Industrial use is the largest consumer of natural gas at 6.3 Bcf/d in 2015 (70% of the total) increasing to 8.7 Bcf/d in 2040 (65% of the

total). Electric Power generation is the second largest consumer of natural gas at 1.1 Bcf/d in 2015 (12.7% of the total) increasing to 2.6 Bcf/d in 2040 (19.5% of the total)¹.

- Canadian Natural Gas production is expected to increase to 17.9 Bcf/d in 2040 from 15.1 Bcf/d in 2015². Non-LNG exports are expected to decrease from 5.2 Bcf/d in 2015 to 0.2 Bcf/d in 2040. The EIA forecasts a similar trend but is slightly more bullish on overall net imports³ to the US indicating 1.6 Bcf/day in 2040⁴. Production from the WCSB in 2015 (14.8 Bcf/d) represents 98% of total Canadian supply and >99% in 2040 (17.8 Bcf/d).
- The NEB Reference Case forecasts natural gas production from the Western Canadian Sedimentary Basin to grow to 17.8 Bcf/d in 2040 from 14.8 Bcf/d in 2015⁵. AB production is forecast to drop to 9.5 Bcf/d in 2040 (53% of the total) from 10 Bcf/d in 2015 (67% of the total) as production grows in BC to meet the forecasted LNG Demand. BC production is forecasted to grow to 8.2 Bcf/d in 2040 from 4.4 Bcf/d in 2015 (46% of Total WCSB production in 2040 from 30% in 2015).
- The NEB EF 2016 provides an estimate of Natural Gas Resource Potential for the Western Canadian Sedimentary Basin (WCSB). Based on 2015 Marketable Production of 5.2 Tcf/year (14.3 Bcf/d), the WCSB has 164 years of remaining life on the Reference Case Remaining Marketable Resource and 255 years at the High Price Forecast⁶.

United States Natural Gas Overview

- The EIA Reference Case expects US Natural Gas Demand increases to 94.3 Bcf/day in 2040 from 75.3 Bcf/d in 2015. In 2040, Electric Power Generation is expected to be the largest demand source at 35% of total demand.
- The EIA AEO2016 Reference Case provides a range of forecast of US Dry Gas Production⁷; dry gas production is expected to grow to 115.4 Bcf/day in 2040 from 74.5 Bcf/day in 2015. In 2040, the US will be a net exporter of natural gas.
- As of Jan 1, 2013, the EIA estimates technically recoverable US dry natural gas resource at 2,300 Tcf⁸. At the 2015 dry gas production rate of 27.2 Tcf/year this represents a life of 84 years.

Canadian and United States Natural Gas Supply, Demand and Systems Comparison

- Both the US and Western Canada have significant natural gas resources and productive capacity (both absolutely and relative to demand).
- Productive capability is diverse and connected to the major demand areas by a network of sales gas pipeline systems.
- Geographically the producing areas are located relatively near the demand centers in both the US and Western Canada.
- One of the key factors in the reliability of the supply sources are the duplication of access paths to market. Western Canada has considerable redundancies built into the system that may not

¹ Includes natural gas consumed in field operations. From the NEB EF 2016

² Excludes natural gas consumed in field operations. From the NEB EF 2016

³ Net imports are defined as imports less exports

⁴ Source US Energy Information Systems (Oct 2008)

⁵ From the NEB EF 2016

⁶ From the NEB EF 2016

⁷ Source US Energy Information Administration (Oct 2008)

⁸ Source US Energy Information Administration (Oct 2008)

be present when a state is dependent upon gas supplies located out of state. This discontinuity does introduce a potential reliability risk that is not present in Western Canada.

Intra Alberta Sales Gas Systems

- AB has a well-established extensive gas transportation network. The combined Nova Gas Transmission Limited (NGTL) and ATCO system is the system most likely to be utilized by the proposed natural gas fired power generation facilities.
- NGTL has developed a sophisticated planning and project execution process to respond to customer requests for new or modified gas receipt or delivery points and to make any existing system modifications required transport gas to Intra AB and export markets.
- The development of West Coast LNG export facilities will have a significant impact on Western Canada gas transportation systems. The impact on the NGTL system in AB will be more significant if the proposed LNG facilities are deferred and or reduced in scope due to increased pressure on the existing system to deliver gas south and east of the growth producing areas.

Intra Alberta Natural Gas System Reliability

- AB has a robust gas supply and delivery system with very high system reliability from producing facilities through the transportation system to end users. The upstream segment of the system consists of a large number of gas gathering and processing facilities that operate essentially independent of each other. The downstream transportation segment has significant redundancy and flexibility to provide alternative gas flow paths in the event of a planned or unplanned outage in one part of the system.
- Reliability of the supply system upstream of natural gas fired power generation facilities is critical. Gas supply assurance is dependent upon three main factors: supply (ultimately resource) availability, capacity of the infrastructure to deliver the required supply and the reliability of that infrastructure to deliver the available resource.
- NGTL has several methods in place to notify customers of planned outages and their impact on customers. The highest gas supply risk due to a single point outage to a specific natural gas fired powered generation facility is a failure or outage on a dedicated single pipeline to the facility. The impact of failures upstream of dedicated pipelines is mitigated by the redundancies and flexibility of the system.
- Depending on the location of new natural gas fired power generation facilities, significant modifications could be required to provide a reliable source of supply. In particular, the infrastructure to supply gas to the Wabamun area west of Edmonton requires upgrading if natural gas fired power generation facilities are located in that area.

Intra Alberta Gas Commercial Arrangements

- The NGTL system provides a well-developed commercial system for transportation and title transfer of gas.
- NGTL system expansions, tolling and operations are under NEB jurisdiction. This requires NGTL to provide services as a common carrier in an open and non-discriminatory fashion.
- Nova Inventory Transfer (NIT) with the Natural Gas Exchange (NGX) and over the counter trading makes AB one of the largest and most liquid gas trading hubs in North America. Typically, gas transfers ownership 5 to 6 times per day before it is delivered off the system.
- Spot market prices in the short term can be sensitive to supply and demand dynamics. Driven

primarily by price, the market balances through changes in storage injects or withdrawals, export balancing and line-pack adjustments. These factors combine to moderate price spikes.

Natural Gas Storage

- There are eight operating natural gas storage facilities in AB with a total storage capacity of approximately 450 Bcf. In BC, the Aitken Creek facility adds another 77 Bcf of storage to western Canada.
- Driven primarily by price signals, storage facilities are used to balance supply and demand needs and can change system balance by up to 2 Bcf/d day over day with a maximum evidenced withdrawal rate from storage of 4 Bcf/d.
- Storage in AB is operated as merchant enterprises (versus regulated open access facilities) where owners negotiate contracts with clients. Commercial terms of these contracts are based on market conditions.

Alberta Natural Gas Fired Power Generation Overview

- The NGTL system currently handles significant seasonal volatility through operational optimization and the use of storage and line pack. The system compensates for periodic large outages or abnormal operating conditions and maintains supply to customers in essentially all circumstances. The current system design can manage storage with withdrawal swings at a rate of up to 2 Bcf/d. However, superimposing large swings in demand (as the result of start-up of substantial natural gas fired power generation) at a time when withdrawals from storage are at maximum (in addition to much smaller weather related swings and larger seasonal variations) is untried and is difficult to predict without a more detailed assessment.
- With installation of large scale natural gas powered electrical generation, we need to assure the ability of the commercial and physical systems to provide short term fuel supply in response to significant and immediate demand increases (0 to 4 hours) and to continue to provide that natural gas over an extended period of time to operate the power generation facilities (24 plus hours). In addition to the flexibility that the normal physical and commercial operation of the NGTL system provides, the specific power generation facilities could install “pipeline” storage to handle periods of short term fuel shortage or install “LNG” storage to handle periods of short term or extended fuel variability or shortage.
- The natural gas supply in Western Canada on a short term basis is relatively inflexible. Fluctuations in natural gas demand are generally managed commercially to access the available natural gas supply. Through the trading desks, the fluctuations in demand are met by accessing gas storage, shifting natural gas export volumes or by re-allocating Intra-Canada demand.

Alberta Natural Gas Fired Power Generation Dependability and Reliability

- The risks associated with the physically and commercially available natural gas supply can be categorized as Western Canada gas resource, Western Canada hourly and daily supply, commercial access, and physical delivery system.
- With respect to overall Western Canadian Natural gas supply (based on the NEB EF 2016 Analysis), the addition of 10,000 MW of natural gas fired power generation will be more than underpinned by the available resource. Anticipated growth of demand for natural gas fired power generation will put upward pressure on the price of natural gas within Western Canada

and, given sufficient cycle time, the development of additional supplies of natural gas to meet the long term need.

- Natural gas movement through the NGTL systems varies over time as demand and supply changes. On a short term basis, natural gas supply is fairly inflexible to daily variations. Short term variations in natural gas demand are met by natural gas withdrawals from storage, re-allocation of natural gas exports or re-allocation of Intra-Western Canada demand.
- Gas supply risk is highest during the period when natural gas storage reservoirs are late in their withdrawal cycle (generally late winter – natural gas demand exceeds supply), shortages in gas supply would result in an increased Western Canada spot price and a shift of gas supply from export and other Intra-Western Canada demand in the response to shifts in net backs. The ability to shift demand decreases as export volumes drop and a higher percentage of demand is focused on electrical power generation. These risks are mitigated by the installation of on-site storage (LNG), assuring commercial access to available gas storage withdrawal volumes or fuel switching. LNG storage options have been discussed in Section 10.

Section 3 - Western Canadian Natural Gas Overview

The following analysis of Western Canadian Natural Gas is based on data sourced from the Alberta Energy Regulator (AER) and the National Energy Board (NEB).

NEB Outlooks

The NEB, in its outlook Canada's Energy Future 2016 (EF 2016), provides an overview of energy supply and demand in each of the Canadian Provinces and Territories and for the Western Canadian Sedimentary Basin (WCSB). A Western Canada look can be developed by summing that from Alberta (AB), British Columbia (BC) and Saskatchewan (SK). The outlook is presented in two reports, Energy Supply and Demand Projections to 2040⁹ and the Province and Territories Outlooks¹⁰ with detailed data backup¹¹. Their projections provide valuable insight into Canada's energy future and a context to understand the development and operation of Natural Gas Fired Power Generation in the Province of AB. In its introduction to its outlook, the NEB indicates:

"The projections presented in both EF 2016 and this supplemental report are a baseline for discussing Canada's energy future and do not represent the Board's predictions of what will take place in the future. The projections in EF 2016 are based on assumptions which allow for analysis of possible outcomes. Any assumptions made about current or future energy infrastructure or market developments are strictly theoretical and have no bearing on the regulatory proceedings that are or will be before the Board.

Only policies and programs that are law at the time of analysis are included in the EF 2016 projections. As a result, any policies under consideration, or new policies developed after the projections were completed in the summer of 2015, are not included in this analysis. Several provinces announced new energy plans and policies prior to the Paris climate conference in late 2015. These announcements and policy changes are not included in the EF 2016 projections¹²."

The EF 2016 contains six Cases for energy supply and demand in Canada covering various uncertainties to 2040. These Cases are outlined in the following figure with overviews of the assumptions in the cases described. For the purpose of this assessment, the Reference Case will be used primarily as its basis. Where applicable, the other Cases have been included to ensure that the range of possible outcomes are considered.

⁹ <https://www.neb-one.gc.ca/nrg/ntgrtd/fttr/2016/2016nrgftr-eng.pdf>

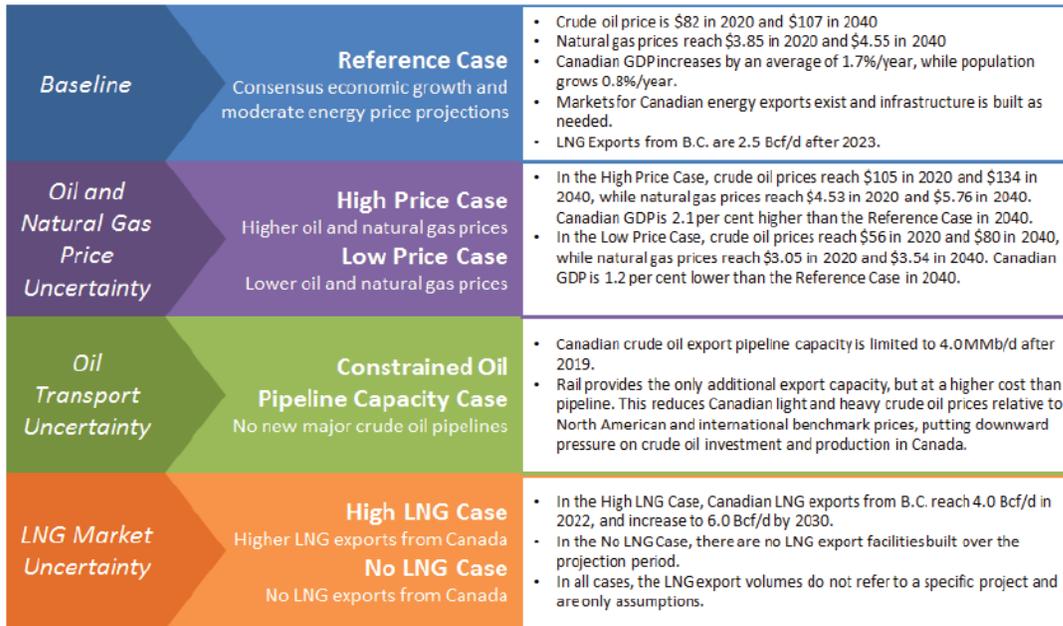
¹⁰ https://www.neb-one.gc.ca/nrg/ntgrtd/fttr/2016pt/nrgyftrs_rprt-2016-eng.pdf

¹¹ [Canada's Energy Future 2016: Update - Energy Supply and Demand Projections to 2040 - Appendices](#) – Oct 2016

¹² From Canada's Energy Future 2016 Province and Territory Outlooks

FIGURE 1.1

Overview of EF 2016 Projections and Key Assumptions



Crude Oil Prices: Brent, 2015 US\$, Natural Gas Prices: Henry Hub, 2015 US\$, Gross Domestic Product (GDP): 2007C\$

Figure 3.1: An Overview of the NEB EF 2016 Projections and Key Assumptions¹³

AER Outlooks

The Alberta Energy Regulatory (AER) annually provides the ST98 Assessment of Alberta’s Energy Reserves (2015) and Supply/Demand Outlook from 2016 to 2025 (ST 98-2016)¹⁴:

“As part of this mandate, one of the AER’s key services is to provide credible information about AB’s energy resources that can be used for good decision making. To this end, the AER issues a report every year that gives stakeholders independent and comprehensive information on the state of reserves, supply, and demand for AB’s diverse energy resources: crude bitumen, crude oil, natural gas, natural gas liquids, sulphur, and coal¹⁵.”

The ST98-2016 provides a single case outlook for AB that can provide further understanding of the energy outlook for the Province as part of this assessment.

Natural Gas Demand

Intra Western Canada – Production

The NEB EF 2016 provides forecasts of demand by energy source (Electricity, Natural Gas, Refined Petroleum Products (RPP) and Liquid Petroleum Gas (LPG), Biofuels and Emerging Fuels, and Others) by Province and Territory. The following analysis sums the Provincial analyses for BC, AB and SK to provide a look for Western Canada. The demand is intra province and does not included gas moved to other

¹³ From Canada’s Energy Future 2016 Province and Territory Outlooks

¹⁴ <http://www.aer.ca/data-and-publications/statistical-reports/st98>

¹⁵ From the ST98-2016 Report

areas of Canada or exported to the United States (US); natural gas exported to the US is analyzed separately. Demand is reported in Pentajoules/year and discussed here in Bcf/day¹⁶;

The NEB analyzes demand as primary and secondary end-use¹⁷. Primary demand is the total energy used including end-use demand and the energy required to generate electricity. It is calculated by adding the energy used to generate electricity (fossil fuels, hydro, nuclear and renewables) to total end-use demand and then subtracting the end-use demand for electricity. Removing end-use electricity demand from the total avoids double counting¹⁸. Secondary (end use) demand is forecast in four categories:

- Residential is the energy consumed by Canadian households. This includes energy used for space and water heating, air conditioning, lighting, large appliances, and other energy using devices like televisions and computers.
- Commercial is a broad category that includes offices, stores, warehouses, government and institutional buildings, utilities, communications, and other service industries. It also includes energy consumed by street lighting and pipelines. Buildings use energy for space and water heating, air conditioning, lighting, appliances and other devices. Pipelines use energy to power pumps or compressors that move oil and natural gas through pipelines.
- Industrial includes manufacturing, forestry, fisheries, agriculture, construction, mining, and oil and natural gas extraction.
- Transportation includes passenger and freight on-road transportation, as well as air, rail, marine, and non-industrial off-road travel, such as recreational all-terrain vehicles and snowmobiles.

Demand includes natural gas consumed in field producing and processing operations. For example, this would include the combustion of natural gas by natural gas producers to operate field gathering, compression and processing. The NEB supply analysis is based on Marketable natural gas that excludes those volumes.

The following chart shows Reference Case natural gas demand by demand type (total including production facility fuel). Total Western Canada Natural Gas Demand is expected to increase to 13.4 Bcf/d in 2040 from 9.1 Bcf/d in 2015. Industrial use is the largest consumer of natural gas at 6.3 Bcf/d in 2015 (70% of the total) increasing to 8.7 Bcf/d in 2040 (65% of the total). Electric power generation is the second largest consumer of natural gas at 1.2 Bcf/d in 2015 (12.7% of the total) increasing to 2.6 Bcf/d in 2040 (19.5% of the total).

¹⁶ Pentajoules/year are converted to Bcf/d by using a factor of 0.9478 Bcf per Pentajoule

¹⁷ Excerpts from the NEB EF 2016

¹⁸ Net natural gas used for electrical power generation is calculated by taking the total adjusted Primary Energy Demand for natural gas and subtracting the Secondary Demand for natural gas

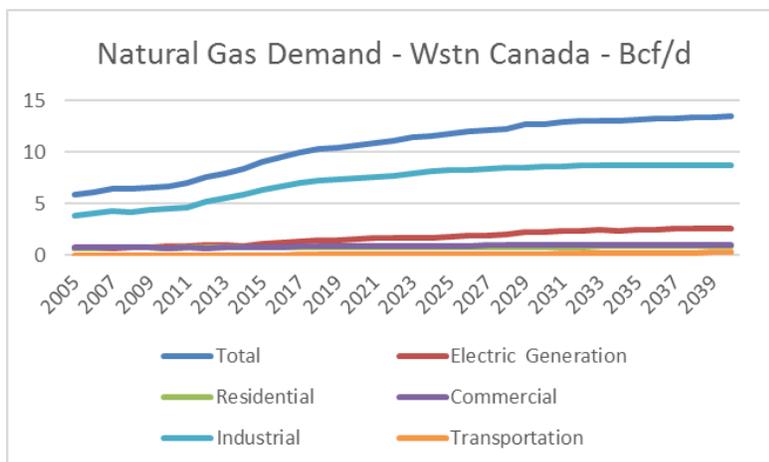


Figure 3.2: Western Canada Natural Gas Demand – By Type¹⁹

Gas used to generate electricity is the second largest component of Western Canada Demand, the following table summarizes that demand by province.

Table 3.1: Western Canada Natural Gas Demand for Electrical Power Generation²⁰

Natural Gas Demand Bcf/d	2015	2025	2040
Alberta ²¹	0.93	1.49	2.13
British Columbia	0.02	0.06	0.06
Saskatchewan	0.18	0.25	0.43
Total	1.15	1.79	2.63

In comparison, the Alberta Energy Regulator estimates the natural gas demand for electrical power generation at 0.8 Bcf/d in 2015 and 1.09 Bcf/d in 2025²².

The following figure shows Reference Case natural gas demand by province (total including production facility fuel). AB is the largest consumer of natural gas in Western Canada at 7 Bcf/d in 2015 (77% of the total) increasing to 10.5 Bcf/d in 2040 (78% of the total). In 2040, the NEB forecasts that total demand intra BC will be 1.5 Bcf/d (11.3% of the total) and in SK 1.4 Bcf/d (10.7% of the total).

¹⁹ Based on data from the EF 2016 Energy Supply and Demand Projections to 2040

²⁰ Based on data from the EF 2016 Energy Supply and Demand Projections to 2040

²¹ The NEB EF 2016 Reference Case forecasts adjusted primary demand for coal in AB will decrease to 300 Pentajoules per year in 2040 from 462 in 2015 (a decrease of 35%) with the assumption that AB coal fired power generation is still operating

²² Based on data from the AER ST98 2016

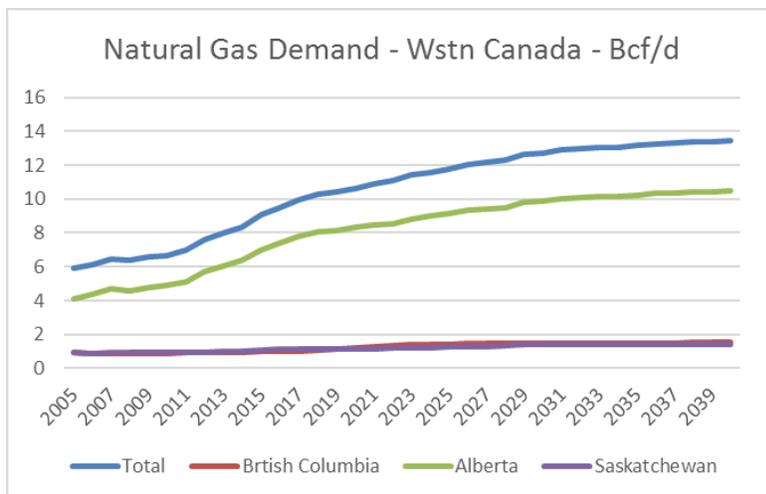


Figure 3.3: Western Canada Natural Gas Demand – By Province²³

Western Canada Exports – Marketable Gas

There are three other sources of demand for Western Canadian natural gas;

1. Movement to other provinces for consumption.
2. Export to the US.
3. Export off shore as Liquefied Natural Gas (LNG).

The NEB EF 2016 provides forecasts for natural gas exports, allowing us to understand the impact that exports have on the overall supply/demand balance. Note that both the following supply and demand forecasts are in Marketable Gas excluding natural gas used to fuel surface production facilities and, as a result, are less than the total demand as summarized in the preceding section.

The following chart shows total Canadian natural gas supply, demand, LNG exports and conventional exports in the Reference Case. Canadian Natural Gas production is expected to increase to 17.9 Bcf/d in 2040 from 15.1 Bcf/d in 2015. Non-LNG exports are expected to decrease from 5.2 Bcf/d in 2015 to 0.2 Bcf/d in 2040. The EIA forecasts a similar trend but is slightly more bullish on overall net imports²⁴ to the US indicating 1.6 Bcf/day in 2040²⁵. Production from the WCSB in 2015 (14.8 Bcf/d) represents 98% of total Canadian supply and >99% in 2040 (17.8 Bcf/d). Total Canadian Demand in the following figure excludes non-marketed natural gas production used directly by those that produce it (including: flared gas, in situ oil sands consumption, etc.).

²³ Based on data from the EF 2016 Energy Supply and Demand Projections to 2040

²⁴ Net imports are defined as US imports less exports

²⁵ Source US Energy Information Systems (Oct 2008)

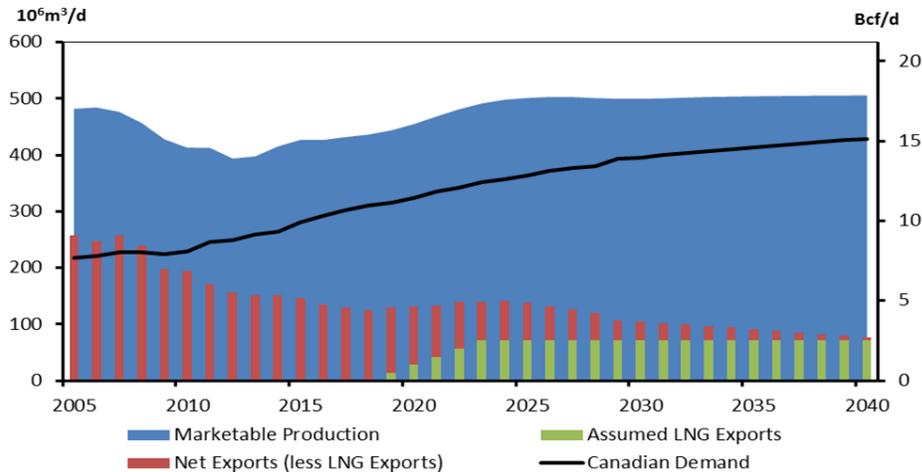


Figure 3.4: Canadian Natural Gas Supply²⁶

The following chart provides a range of net exports in the High, Low and Reference Case. Net exports are the difference between Canadian marketable natural gas and Canadian demand and include both conventional and LNG volumes. In the Reference Case, export volumes decline until 2019 when the first exports of LNG are forecasted to begin. Growth in LNG Exports continue until 2023 after which total exports decline to 2040. In the High Price Case, exports continue to grow due to the higher natural gas prices. The converse occurs in the Low Price Case.

FIGURE 6.6
Canadian Net Exports of Natural Gas, Reference, High and Low Price Cases

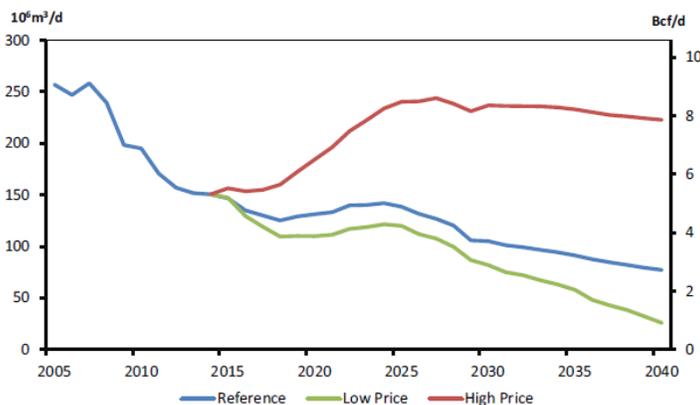


Figure 3.5: Canadian Net Exports of Natural Gas²⁷

One of the key variables to be considered in WCSB demand is the timing and pace of West Coast LNG Development. The NEB considered three LNG Development Cases in the EF.2016 analysis; High, Reference and No Development.

The following figure shows forecast LNG Exports from the WCSB in the 3 LNG Cases. The Reference and High Cases assume the start-up of initial liquefaction capacity in 2018/19. In 2019, the Reference Case indicates 0.3 Bcf/d of LNG exports with 0.8 Bcf/d in the High Case. The Reference Case indicates peak

²⁶ Based on data from the EF 2016 Energy Supply and Demand Projections to 2040

²⁷ From the EF 2016 Energy Supply and Demand Projections to 2040

capacity development in 2026 to 2040 with 2.4 Bcf/d of Exports. The High Case indicates peak capacity development in 2034 to 2040 with 6.2 Bcf/d of exports. LNG is forecast to be a significant component of required supply by 2040. In the Reference Case LNG represents 14% of the supply requirement and 29% in the High Case²⁸.

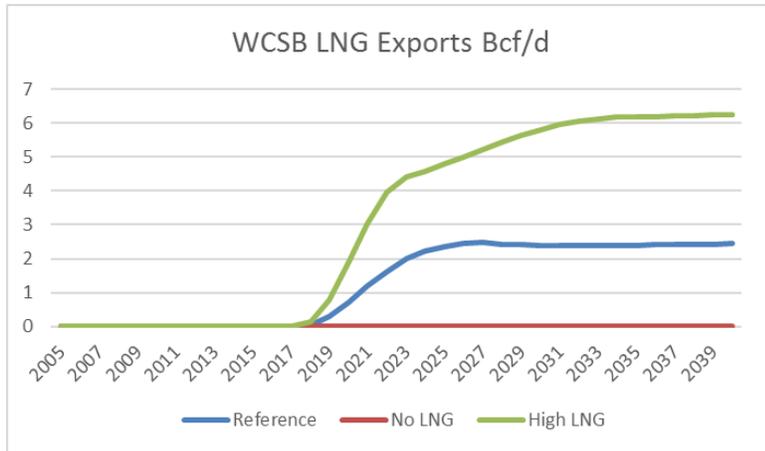


Figure 3.6: WCSB LNG Exports²⁹

The following figure summarizes (at the end of 2015) Global LNG Supply and the LNG Liquefaction Capacity that was under construction as of that date, projects under construction (mostly in the US and Australia) would add 13 Bcf/d of capacity.

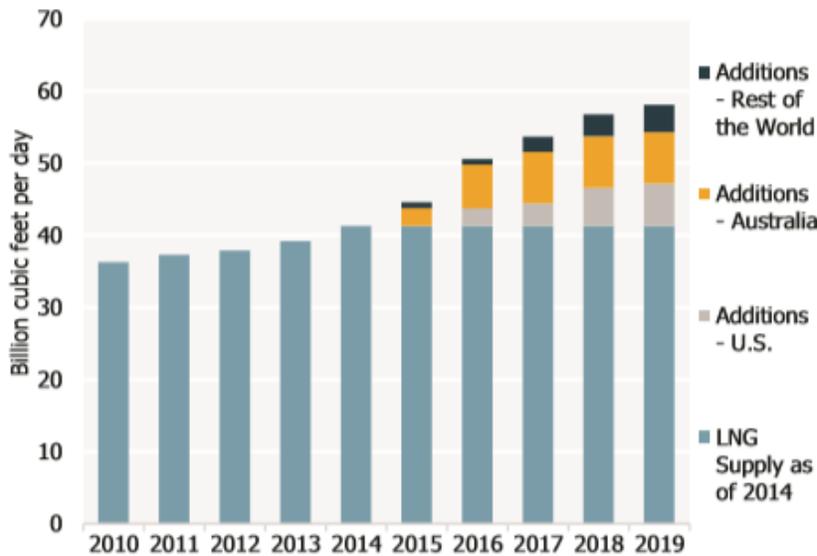


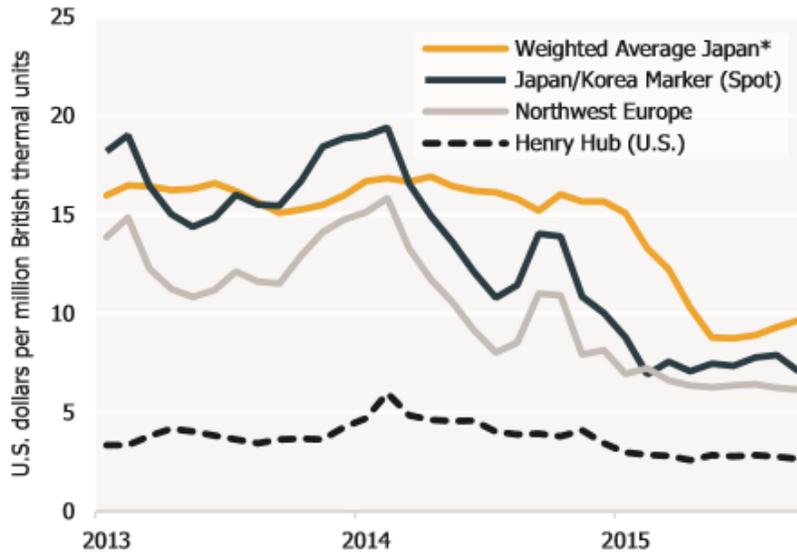
Figure 3.7: Worldwide LNG Liquefaction Capacity Additions³⁰

²⁸ Since the NEB prepared the EF 2016 forecast, the projects being developed in Western Canada have slowed; on stream dates in the late 2010's or early 2020's are probably overly optimistic. Peak development forecast in the out years of the forecast (2030+) may still be realistic

²⁹ Based on data from the EF 2016 Energy Supply and Demand Projections to 2040

³⁰ NEB Canadian Energy Dynamics Highlights of 20015 - Figure 17 LNG Liquefaction Capacity 2010 to 2019

The following figure summarizes LNG pricing in 2015 relative to 2013/14. The monthly average Japan Korea Marker spot price fell from a high of US\$19.40 per MMBtu in early 2014 to an average of US\$7.45 per MMBtu in 2015. Pricing of LNG traded under oil-linked contracts dropped in response to the decline in crude oil prices.



* Average LNG import price for Japan.

Figure 3.8: LNG and Henry Hub Natural Gas Prices³¹

These changes in the world LNG Market has introduced uncertainty in the timing and ultimate development of Canadian LNG. Curtailment of development would put pressure on Canadian natural gas pricing as supply competes for existing markets in Canada and the US and would result in slowed development as economics are negatively impacted.

Alberta – Marketable Gas

The AER ST98-2016 analysis contains historical and forecast (to 2025) natural gas demand and production data. The analysis provides a complete view of AB demand as it includes gas that is moved out of the Province within Canada and for export to the US. Demand and Supply is expressed in Marketable Gas³² that excludes natural gas used in Production Operations. As a result, the forecasts are less than that incorporated into the NEB total demand for AB as that analysis includes gas consumption for production and processing operations.

The following figure shows natural gas demand for AB to 2025³³. Total natural gas demand in AB in 2015 was 10.6 Bcf/day and forecast to decrease to 8.1 Bcf/day in 2025. In 2015, intra-AB demand accounted for 49% (5.2 Bcf/day) of total AB demand, increasing to 69% (6.3 Bcf/day) in 2025. Removals (to Eastern Canada and export to the US) are forecasted to decrease to 2.5 Bcf/day in 2025 from 5.4 in 2015. Oilsands industrial use is the largest consumer of natural gas in the province accounting for 34% of intra-

³¹ NEB Canadian Energy Dynamics Highlights of 2015 - Figure 18 LNG and Henry Hub Natural Gas Prices

³² The AER defines marketable gas as the gas that remains after the raw gas is processed to remove nonhydrocarbons and heavier natural gas liquids and that meets specifications for use as a fuel

³³ From the ST98 Report

AB demand in 2015 (1.8 Bcf/day) and forecast to increase to 45% in 2025 (2.9 Bcf/day). Electricity generation accounts for 16% of intra-AB demand in 2015 (0.8 Bcf/day) and is forecast to increase to 17% in 2025 (1.1 Bcf/day).

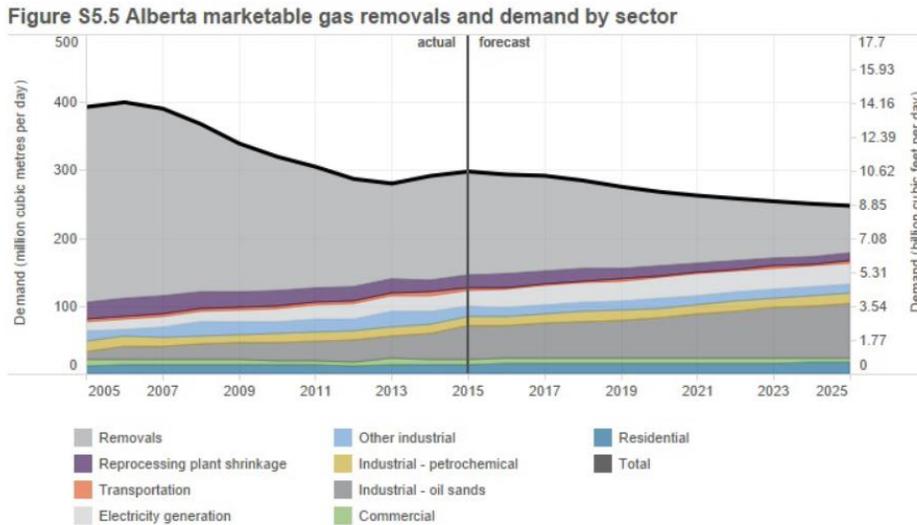


Figure 3.9: Alberta Marketable Gas Removals and Demand by Sector³⁴

One of the components of natural gas demand in AB is gas consumed in the production of crude bitumen. The AER in its ST98 analysis forecasts both Crude Bitumen production and related natural gas demand. From the AER Website:

“Crude bitumen is extra-heavy oil that in its natural state does not flow to a well. It occurs in sand (clastic) and carbonate formations in northern AB. Crude bitumen and the rock material it is found in, together with any other associated mineral substances other than natural gas, are called oil sands. For administrative purposes, the geological formations and the geographic areas containing the bitumen are designated as oil sands areas (OSAs). Combined, these areas occupy an area of about 142 000 square kilometers (km²) (54 000 square miles). Other heavy oil is deemed to be oil sands if it is located within an OSA. Since some bitumen within an OSA will flow to a well, it is amenable to primary development and is considered to primary crude bitumen in this report³⁵.”

From the ST98 Analysis, the following figure summarizes the AER’s forecast of Crude and Bitumen production to 2025.

³⁴ Figure S5.5 is from the ST98 2016 Website Report

³⁵From the ST98 Report

Figure S3.3 Alberta crude bitumen production

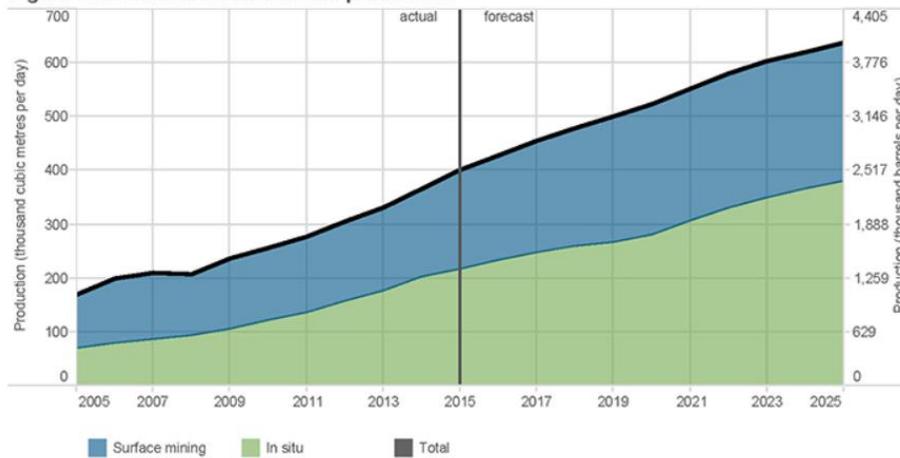


Figure 3.10: Alberta Crude Bitumen Production³⁶

From the ST98 Analysis;

“Total mineable raw production is expected to grow 40 per cent by 2025 relative to 2015 levels; Suncor’s Fort Hills and further expansions at Imperial’s Kearl are forecast to contribute the bulk of the added production. Compared to 2015, total in situ production is expected to grow 75 per cent by 2025. As with mineable production, the outlook for in situ production is slightly lower relative to last year’s forecast due to the reassessment of project start dates in light of the current low price environment.”

The following figure shows Natural Marketable Gas Demand for AB Industrial – Oil Sands³⁷. Consumption is forecast to increase from 1.8 Bcf/d in 2015 (17% of total AB Demand) to 2.9 Bcf/d in 2025 (32%). Changes in development of crude and bitumen has the potential to substantially impact the demand for Marketable Gas in AB.

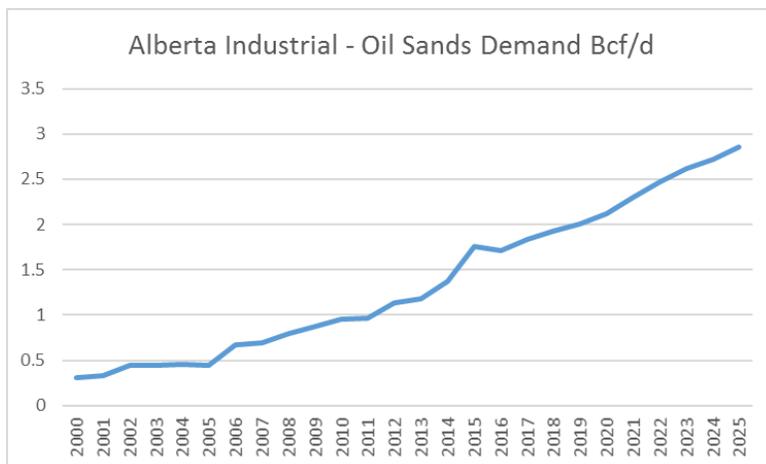


Figure 3.11: Alberta Industrial – Oil Sands Natural Gas Demand³⁸

³⁶ Figure S3.3 is from the AER ST98 2016 Website Report

³⁷ From ST98

³⁸ Based on data from the AER ST 98 Report

Natural Gas Supply – Marketable Gas

Western Canada – Western Canadian Sedimentary Basin

The NEB EF 2016 provides outlooks of natural gas supply by Province and Territory and for the Western Canadian Sedimentary Basin (WCSB)³⁹. The following analysis is for the WCSB.

The following chart shows WCSB natural gas supply to 2040 in the 6 NEB analyzed cases⁴⁰ (marketable gas). The Reference Case forecasts natural gas production from the Western Canadian Sedimentary Basin to grow to 17.8 Bcf/d in 2040 from 14.8 Bcf/d in 2015.

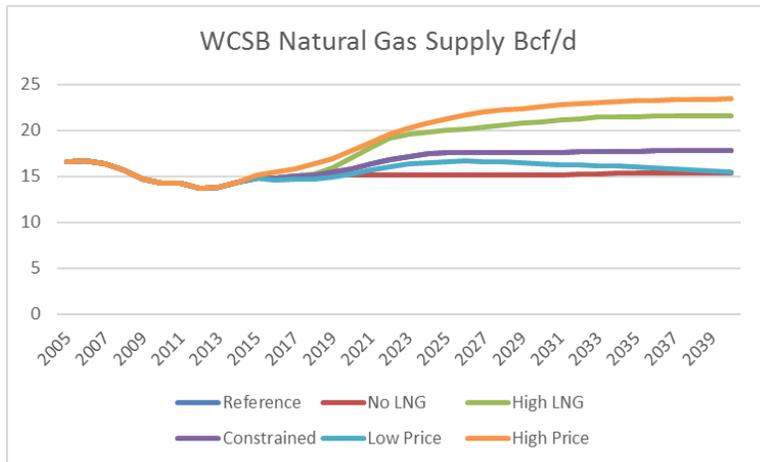


Figure 3.12: WCSB Natural Gas Supply by Case⁴¹

The following chart shows WCSB natural gas supply to 2040 by Province for the Reference Case (marketable gas). AB production is forecast to drop to 9.5 Bcf/d in 2040 (53% of the total) from 10 Bcf/d in 2015 (67% of the total) as production grows in BC to meet the forecasted LNG Demand. BC production is forecasted to grow to 8.2 Bcf/d in 2040 from 4.4 Bcf/d in 2015 (46% of total WCSB production in 2040 from 30% in 2015).

³⁹ The Western Canadian Sedimentary Basin (WCSB) is the sedimentary basin underlying most of Western Canada including southwestern Manitoba, southern Saskatchewan, AB, northeastern BC and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east. This wedge is about 6 kilometers (3.7 miles) thick under the Rocky Mountains, but thins to zero at its eastern margins. The WCSB contains one of the world's largest reserves of petroleum and natural gas and also has huge reserves of coal. Of the provinces and territories within the WCSB, AB has most of the oil and gas reserves and almost all of the oil sands. From EF 2016

⁴⁰From EF 2016

⁴¹ Based on data from the EF 2016 Energy Supply and Demand Projections to 2040. Note that the Reference and Constrained Cases data sets plot over each other

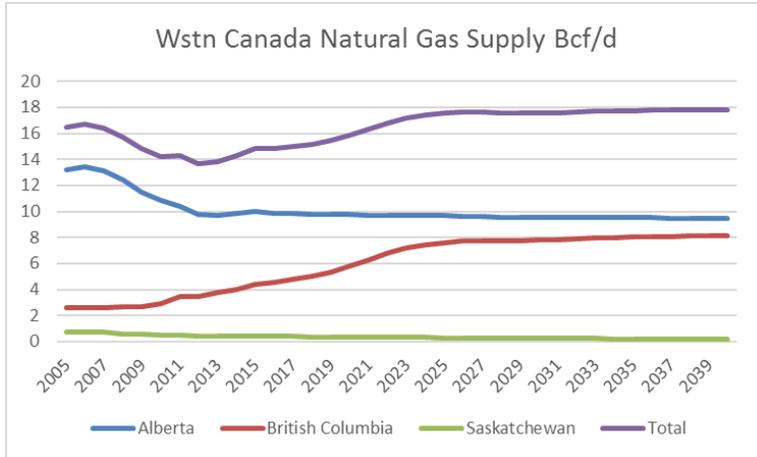


Figure 3.13: Western Canada Natural Gas Supply by Province⁴²

Alberta

As with demand, the AER analyzes natural gas production in the ST98-2016 Report. Production is reported by gas type (coal bed methane (CBM), shale gas and gas from oil wells) and by the Petroleum Services Association of Canada (PSAC) areas for conventional production; the following map highlights the PSAC areas.

⁴² Based on data from the EF 2016 Energy Supply and Demand Projections to 2040

PSAC Areas

The Petroleum Services Association of Canada (PSAC) has sectioned Canada into a number of geographic regions based on the predominate type of geological interest to the oil and gas industry. Figure AA.1 shows the PSAC areas in Alberta. The AER often refers to the historical, current, and future oil and gas activity it discusses by PSAC area.

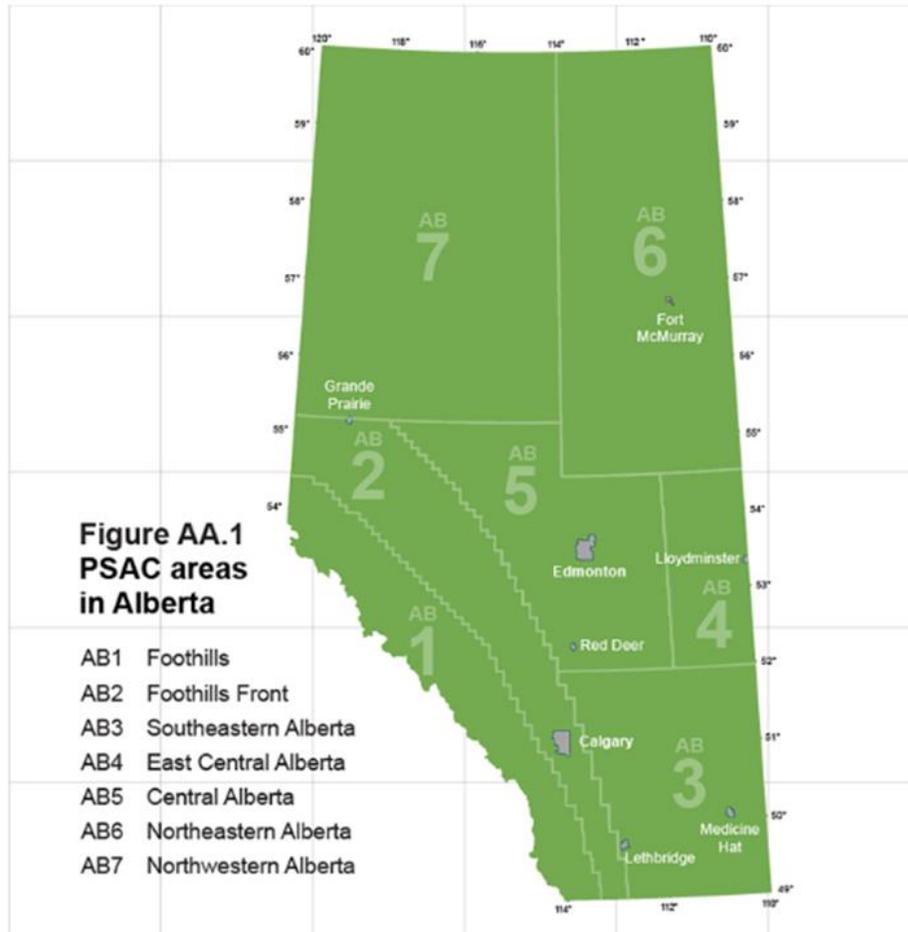


Figure 3.14: Petroleum Services of Canada Natural Gas Forecasting Areas⁴³

The following chart shows AB Supply by PSAC area⁴⁴ (marketable gas). Marketable Natural Gas production in the province is forecast to drop to 8.8 Bcf/day in 2025 from 10.6 Bcf/day in 2015. The largest production area is the Foothills Front accounting for 47% of AB production in 2015 (5 Bcf/day) and forecasted to increase to 52% in 2025 (4.57 Bcf/day).

⁴³ The figure is from the ST98 Report

⁴⁴ From the ST98 Report

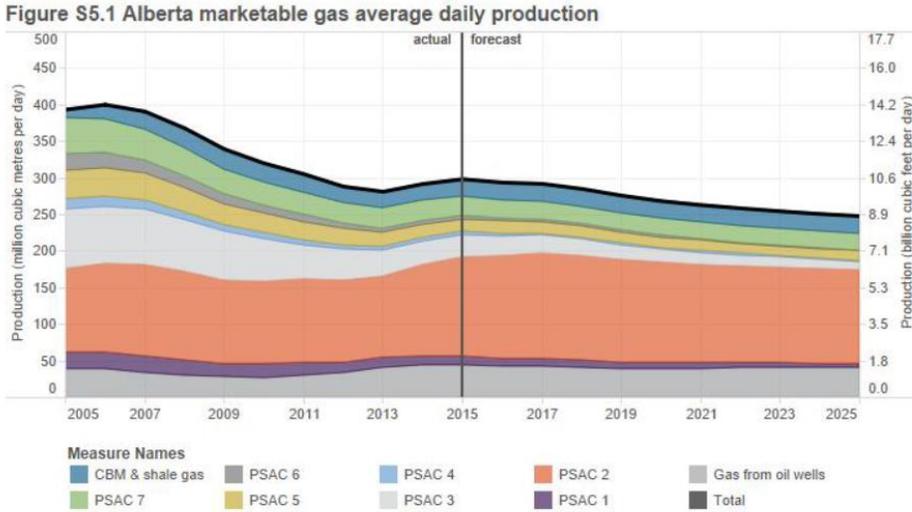


Figure 3.15: AB Marketable Gas Production by Geographic Area⁴⁵

The following chart shows the AER and NEB forecasts of natural gas supply (marketable gas). The NEB’s Canada’s EF 2016 indicates a slightly less conservative view of AB forecasted production. The EF 2016 Reference Case production is forecast at 9.5 Bcf/d in 2040 down from 10 Bcf/d in 2015. The outcomes from the five Cases range from a high of 13 Bcf/d (High Price) to 8 Bcf/d (Low Price) in 2040. The AER ST 98 forecast is slightly higher historically and approximates the NEB Low Case Forecast.

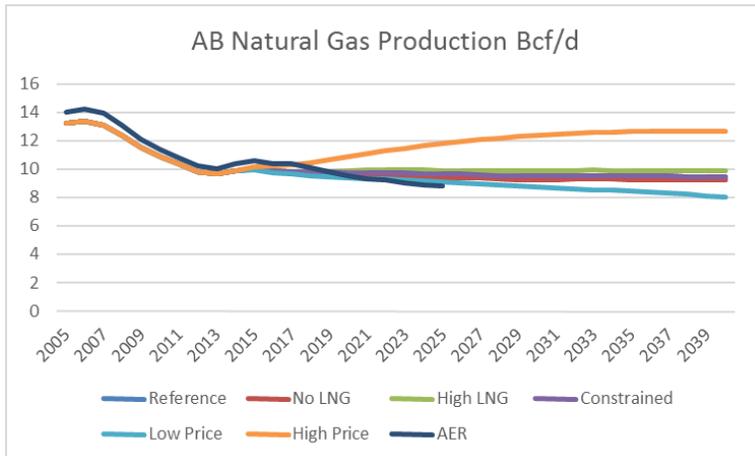


Figure 3.16: AB Natural Gas Production by Case⁴⁶

Impact of Hydraulic Fracturing

One of the key technology advances that has impacted the supply and resulting price of natural gas has been the advent of long reach horizontal well drilling and multi stage hydraulic completions. These approaches have allowed the industry to produce natural gas (and oil) from tight conventional and shale formations that had previously been uneconomic to develop. These advancements have also triggered

⁴⁵ Figure S5.1 is from the AER ST98 2016 Website Report

⁴⁶ Based on data from the AER ST98 Report and from the EF 2016 Energy Supply and Demand Projections to 2040. Note that the Reference and Constrained Cases data sets plot over each other

considerable discussion on the expansion of hydraulic fracturing and the impact that it could have on ground water supplies. The NEB EF 2016 provides an outlook of natural gas production for the WCSB by gas type that provides some insight into future gas production and infer the potential for curtailment of supply should significant changes be made to the regulations that support the use of hydraulic fracturing and the development of the corresponding resource.

The following chart shows the Reference Case forecast by gas type (marketable gas). Tight gas is the predominate gas type by 2040 growing to 13.6 Bcf/d in 2040 from 8 Bcf/d in 2015 (77% of total WCSB production in 2040 from 54% in 2015). In the Reference Case, there is some growth in Shale gas as production grows to 1.1 Bcf/d in 2040 from 0.6 Bcf/d in 2015. In combination, tight and shale gas are anticipated to provide 83% of the overall gas supply in the Reference Case.

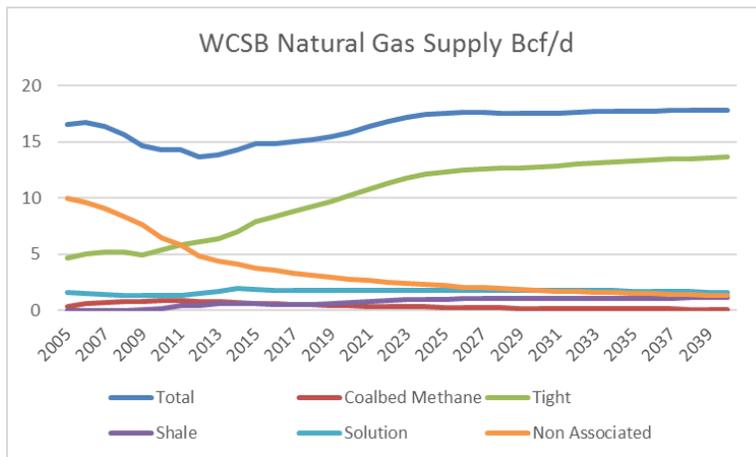


Figure 3.17: WCSB Natural Gas Supply by Play Type⁴⁷

Within the Canada, regulations that control hydraulic fracturing and their impacts are primarily a provincial responsibility. With the development of a high percentage of the natural gas supply currently dependent upon hydraulic fracturing, any significant changes to that practice (disallowing or curtailing hydraulic fracturing) would have an impact on the natural gas supply.

Natural Gas Resource Potential

One of the key variables that need to be considered is the remaining recoverable resource in Western Canada and in AB.

Western Canada Sedimentary Basin

The NEB EF 2016 provides an estimate of Natural Gas Resource Potential for the Western Canadian Sedimentary Basin. The following table shows remaining Marketable Resource for 3 Cases (Reference, Low Price and High Price). Based on the 2015 WCSB Marketable Production of 5.2 Tcf/year (14.3 Bcf/d), the WCSB has 164 years of remaining life on the Reference Case Remaining Marketable Resource and 255 years at the High Price Forecast.

⁴⁷ Based on data from the EF 2016 Energy Supply and Demand Projections to 2040

Table 3.2: WCSB Marketable Resource⁴⁸

WCSB Remaining Marketable Resource (Tcf)	Reference	Low Price	High Price
Conventional ⁴⁹	599	474	936
Tight Gas Portion ⁵⁰	528	403	866
Montney Tight Gas Portion	447	348	738
CBM	34	20	52
Shale Gas ⁵¹	222	157	337
Horn River Portion	78	61	96
Sub Total	855	651	1325

Natural Gas Resource Potential – Alberta

The following table shows resource at year end 2015 for AB. Based on 2015 Production of 3.9 Tcf/year (10.7 Bcf/d - as compared to Marketable Production of 8.8 Bcf/d), the Province has 8 years of remaining life on its Established Reserves and 57 years of remaining life on its Ultimate Recoverable Resource⁵².

Table 3.3: Alberta Resource⁵³

AB Resource (Tcf)	
Initial in-place Resources	351
Initial established Reserves	201
Cumulative Production	169
Remaining Established Reserves	31.3
Annual Production	3.9
Ultimate potential recoverable Resource (excluding unconventional natural gas)	223

⁴⁸ Based on data from the EF 2016 Energy Supply and Demand Projections to 2040

⁴⁹ Includes the following tight gas and Montney Resources

⁵⁰ Includes the following Montney Resource

⁵¹ Includes the following Horn River Resource

⁵² Note that the AB resource numbers exclude unconventional natural gas resources

⁵³ Based on data from the AER ST98 2016 analysis (Table 1 Executive Summary)

Section 4 – United States Natural Gas Overview

The major impacts of the replacement of coal fired power generation in AB will be on the Western Canada natural gas systems, however those systems are linked to the US and need to be understood in the larger context.

The following analysis of US Natural Gas Demand and Supply is based on information sourced from the US Energy Information Administration (EIA) Website and Publications. The EIA is part of the US Department of Energy and a principal agency of the US Federal Statistical System responsible for collecting, analyzing, and disseminating energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. EIA programs both short and long term energy outlooks for all types of energy used in the US. (Petroleum and Other Liquids, Natural Gas, Electricity, Coal, Renewables and Alternate Fuels, and Nuclear and Uranium).

Key sources of data for the US natural gas system from the EIA include the: Annual Energy Outlook 2016, Natural Gas 2015 Annual Publications and latest AEO2016 Energy Forecasts. For the purpose of this analysis, the Reference Case from the AEO2016 Forecast will provide key data and insights.

The AEO2016 forecast generally contains a spread of outcomes based on the impact of three oil price inputs. From the EIA Website:

“Key influences on consumption and production are price trends and the reactions of consumers and producers to those trends, which in turn influence future prices. EIA has developed three price cases to examine a range of potential interactions of supply, demand, and prices in world liquids markets: The Reference case and alternative Low Oil Price and High Oil Price cases. While the three oil price cases represent a wide range of uncertainty in future markets, they do not capture all possible outcomes. Because EIA's oil price paths represent market equilibrium between supply and demand, they do not show the price volatility that occurs over days, months, or years.”

The following figure shows the oil price forecast that is the basis of the 3 oil based EIA Modelled Cases⁵⁴.

⁵⁴ Source US Energy Information Systems (Oct 2008)

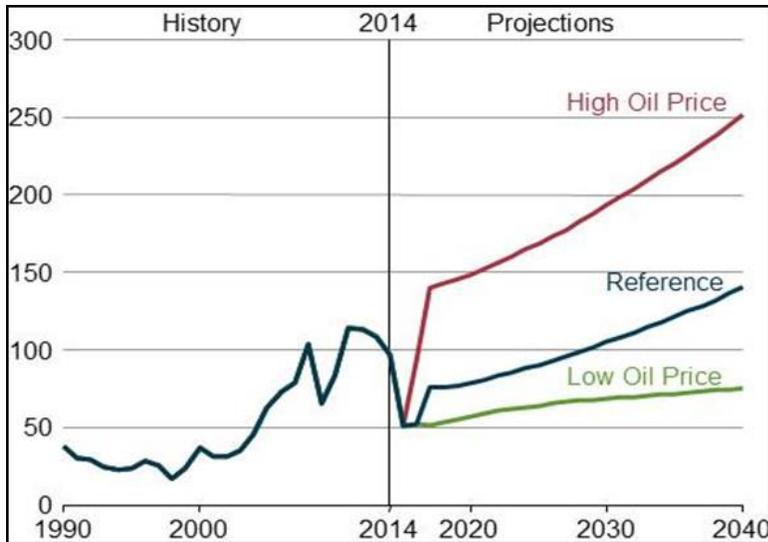


Figure 4.1: EIA Model Price Assumptions⁵⁵

The following figure shows the Natural Gas pricing assumptions in the five Modelled Natural Gas Cases included in the EIA assessment⁵⁶. Within that forecast, the price of natural gas is affected by the oil prices through changes in consumption and exports and the rate of resource recovery from oil and natural gas wells and by technology improvements which affect natural gas production and the associated costs. As a result, two additional cases are added; the High Oil and Gas Technology Case (with higher initial estimated ultimate recovery per well and more rapid technology improvements) and the Low Oil and Gas Resource and Technology Case (with slower rates of resource recovery and technology improvements). For the purpose of this analysis, generally the Reference Case is used as the basis for the assessments. Dry natural gas production in the High Technology Case is 32% higher than the Reference Case and the Low Technology Case 37% less.

⁵⁵ Source US Energy Information System (Oct 2008). Figure 2-1. North Sea Brent crude oil spot prices in three cases, 1990-2040 (2013 dollars per barrel)

⁵⁶ Source US Energy Information System (Oct 2008)

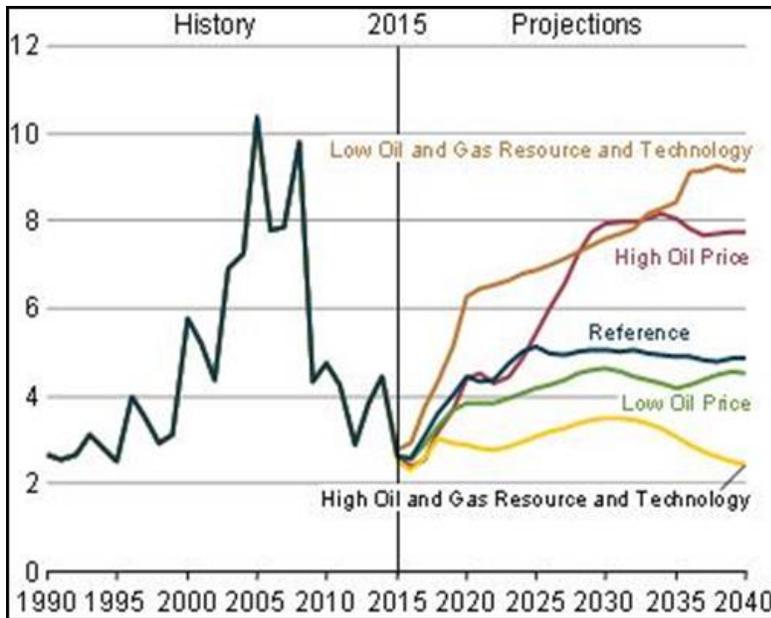


Figure 4.2: EIA Natural Gas Model Price Assumptions⁵⁷

US Natural Gas Demand

The EIA AEO2016 Reference Case provides a forecast of US Dry Gas Consumption. The following figure shows Reference Case Dry Gas Consumption by category⁵⁸. Within that forecast, the key demand growth areas are Industrial and Electricity Generation.

Table 4.1: US Natural Gas Demand⁵⁹

US Consumption of natural gas (Tcf/year)	2015	2025	2035	2040
Residential	4.6	4.7	4.6	4.6
Commercial	3.2	3.4	3.6	3.7
Industrial	7.5	8.7	9.2	9.6
Electricity Generation	9.6	9.3	11.0	12.0
Other	2.51	3.34	4.09	4.6
Total	27.5	29.35	32.59	34.42

Natural gas consumed in electrical generation is of specific interest as the assumptions around the shutdown of coal fired power generation and the development of renewables have an impact on that demand. In the US, the Clean Air Act (CAA) sets the regulatory framework for federal efforts to control emission of air pollutants; within those provisions, the US Environmental Protection Agency (EPA) has developed a program to limit CO₂ emission from the electrical power sector by setting CO₂ performance standards for new and existing power plants (the Clean Power Plan (CPP)). These rules were published in 2015 taking effect in 2022 but stayed by a Supreme Court Ruling in 2016. As a result, the AEO2016 Reference Case includes both a CPP and an alternative No CPP Case. EIA AEO2016 CPP Reference Case

⁵⁷ Source US Energy Information System (Oct 2008). Figure MT-42. Annual average Henry Hub natural gas spot market prices in five cases, 1990–2040 (2015 dollars per million Btu)

⁵⁸ Source US Energy Information Administration (Oct 2008)

⁵⁹ Source US Energy Information Administration (Oct 2008)

provides a forecast of net electricity generation by fuel as indicated in the following figure⁶⁰. That Case assumes that the US Clean Power Plan is implemented and indicates that net electricity generated plus net imports will increase to 5,060 billion kilowatt-hours in 2040 from 4,090 in 2015. Net electricity generation from natural gas will increase to 1,942 billion kilowatt-hours in 2040 from 1,348 in 2015. During the same period net electricity generated from coal drops to 919 in 2040 from 1,355 in 2015. By 2040, the EIA forecasts that as a percentage of total electrical generation, net electricity generated from coal will decrease to 18% in 2040 from 33% in 2015.

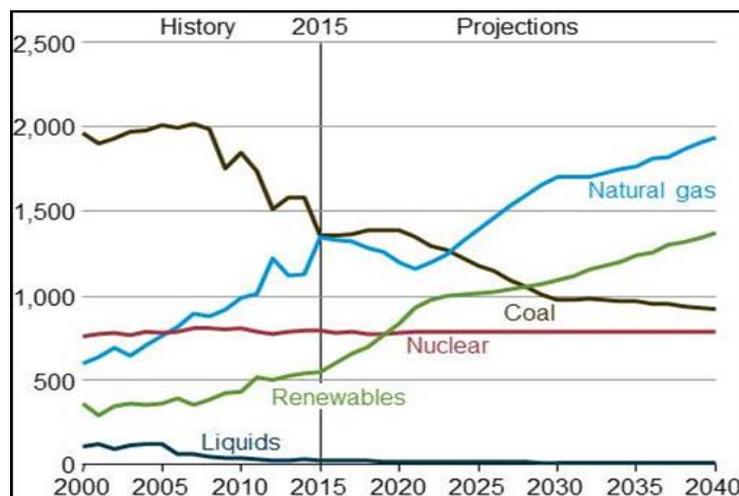


Figure 4.3: US Net Electrical Generation by Fuel Source – CPP Case (billion kilowatt-hours)⁶¹

An understanding of the impact on natural gas used for electrical power generation can be gained through a similar EIA forecast in the Non-CPP case. The EIA AEO2016 No CPP Reference Case provides a forecast of net electricity generation by fuel as indicated in the following figure⁶² without the implementation of the Clean Power Plan (CPP). With No CPP, coal fired net electricity generation shows little change to 2040. In this case, the growth in net electricity demand is met through the growth in renewables and natural gas fired power generation. Overall, in the comparison of the two cases there is little difference in natural gas fired electricity generation as growth in electricity demand is increased in the No CPP case due to its lower electricity price structure.

⁶⁰ Source US Energy Information Administration (Oct 2008)

⁶¹ AEO2016 Market Trends - Figure MT-28. Net electricity generation by fuel in the Reference case, 2000–2040 (billion kilowatt-hours)

⁶² Source US Energy Information Administration (Oct 2008)

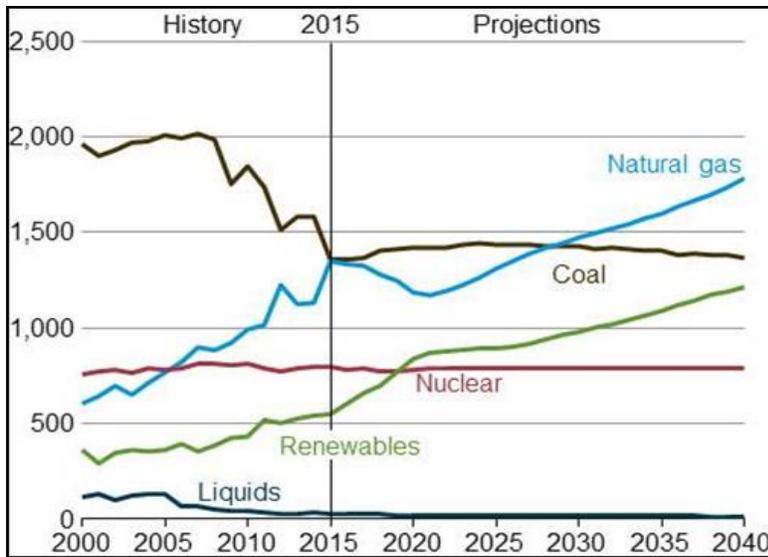


Figure 4.4: US Net Electrical Generation by Fuel Source – No CPP Case (billion kilowatt-hours)⁶³

On an overall basis, the consumption of natural gas for electricity increases by about 10% in the CPP in comparison to the No CPP case. In 2040, total natural gas consumption for electricity in the CPP case is forecast at 11.96 Tcf/year; a 10% increase would require another Tcf/year of supply, a relatively small amount relative to the total demand of 34.42 Tcf/year and the available supply. As a result, we can conclude that, within the EIA Forecasting assumptions, accelerated shut down of coal fired power generation in the US would have limited impact on the US natural gas supply/demand balance and no impact on the demand for Canadian Natural Gas.

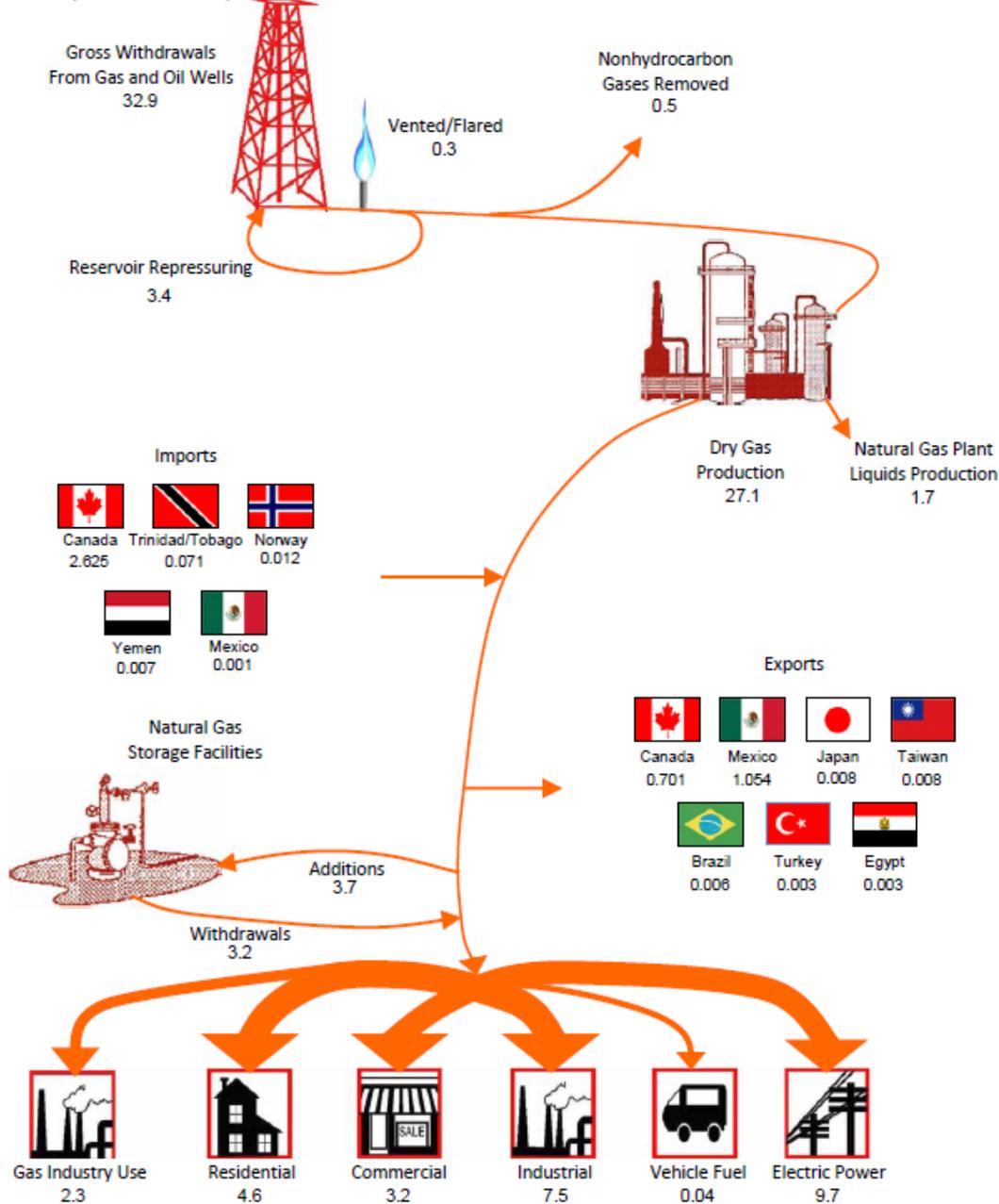
US Natural Gas Supply

The supply of natural gas is a primary energy source in the US and a complicated mix of domestic production, imports and exports. The following figure provides a snap shot of that supply for the year 2015⁶⁴.

⁶³ EIA AEO2016 Market Trends –Figure MT-29. Net electricity generation by fuel in the No CPP case, 2000–2040 (billion kilowatt-hours)

⁶⁴ Source US Energy Information Administration (Oct 2008)

Figure 2. Natural gas supply and disposition in the United States, 2015
(trillion cubic feet)



Sources: Energy Information Administration (EIA), Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition"; Form EIA-914, "Monthly Natural Gas Production Report"; Form EIA-837, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers"; Form EIA-816, "Monthly Natural Gas Liquids Report"; Form EIA-844, "Annual Report of the Origin of Natural Gas Liquids Production"; Form EIA-191, "Monthly Underground Gas Storage Report"; Office of Fossil Energy, U.S. Department of Energy, "Natural Gas Imports and Exports"; the Bureau of Safety and Environmental Enforcement and predecessor agencies; Form EIA-923, "Power Plant Operations Report"; Form EIA-886, "Annual Survey of Alternative Fueled Vehicles"; state and federal agencies; Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves"; PointLogic Energy; DrillingInfo; Ventyx; and EIA estimates based on historical data.

Figure 4.5: Schematic of US Natural Gas Supply and Demand⁶⁵

The EIA AEO2016 Reference Case provides a range of forecast of US dry gas production (see the above figure) as indicated in the following figure⁶⁶ Dry gas production is expected to grow to 42.1 Tcf/year in

⁶⁵ Source US Energy Information Administration (Oct 2008). EIA – Natural Gas Annual 2015

⁶⁶ Source US Energy Information Administration (Oct 2008)

2040 from 27.2 Tcf/year in 2015. In 2040, dry gas production varies by 7.8 Tcf/year across the oil price cases.

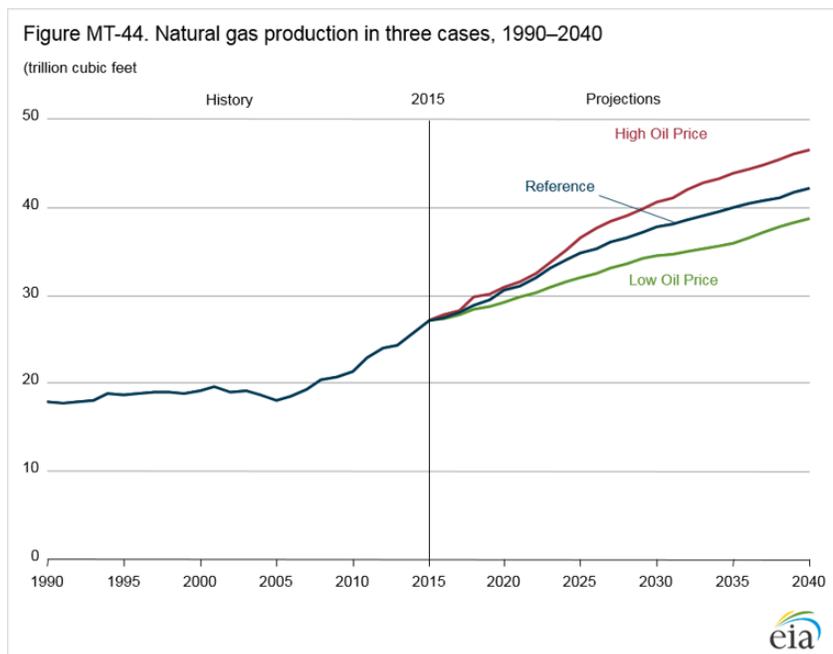


Figure 4.6: US Natural Gas Production⁶⁷

Natural Gas produced in Canada is moved to the US through a network of pipelines as indicated on the following map⁶⁸: There are four major pipeline corridors moving Canadian natural gas to the US:

- Canada Western (labelled #6)** - from Western Canada to the Western US (principally California, Oregon, and Washington State). The route brings natural gas from AB and BC, through Washington, Idaho, and Oregon, with terminating points in Nevada and California. In Canada, Spectra Energy Corporation's Westcoast Gas Transmission Ltd. and Alberta Natural Gas Ltd. (in association with Foothills Pipeline Ltd.) receive gas from NGTL (NOVA) in AB and transport that gas to the US border. There the supplies are received by Northwest Pipeline Company (from Westcoast Gas Transmission) and Gas Transmission Northwest.
- Canada Midwest (labelled #7)** - from the Western Canada to the Midwestern US. This transportation corridor lies between Western Canadian supply areas and the US Midwest and links two Canadian systems, TransCanada Pipeline Ltd. and Foothills Pipeline Company, with three US pipeline systems, Great Lakes Gas Transmission Company, Northern Border Pipeline Company and Viking Gas Transmission Company. In addition, the 1,300-mile Alliance Pipeline, provides a direct transportation route for "wet" (natural gas high in liquids content) between producing fields in northwestern BC and AB, and a gas-processing plant (Aux Sable) located outside Chicago, Illinois.
- Canada Northeast (labelled #8)** - from Western Canada to Northeastern markets in the US. The western portion of the Canada-Northeast corridor links the TransCanada Pipeline system (and

⁶⁷ AEO2016 Market trends - Figure data - August 25, 2016. Figure MT-44. Natural gas production in three cases, 1990–2040 (trillion cubic feet)

⁶⁸ Source US Energy Information Administration (Oct 2008)

Western Canadian gas production) to seven pipeline companies in the Northeastern US. The seven are: Iroquois Pipeline Company, North Country Pipeline Company, the Portland Gas Transmission System, Tennessee Gas Pipeline Company, Empire Pipeline Company, Vermont Gas Company, and St. Lawrence Gas Company. Indirectly, the corridor also supplies gas to the National Fuel Gas Supply Company and Dominion Transmission Company.

- **Eastern Offshore Canada Northeast (labelled #9)** - from the area of offshore eastern Canada (Sable Island) to New England markets in the US This corridor consists primarily of the Maritimes and Northeast Pipeline system, which can transport natural gas into the United States from off the eastern coast of Canada at Sable Island.

Major U.S. Natural Gas Transportation Corridors, 2008

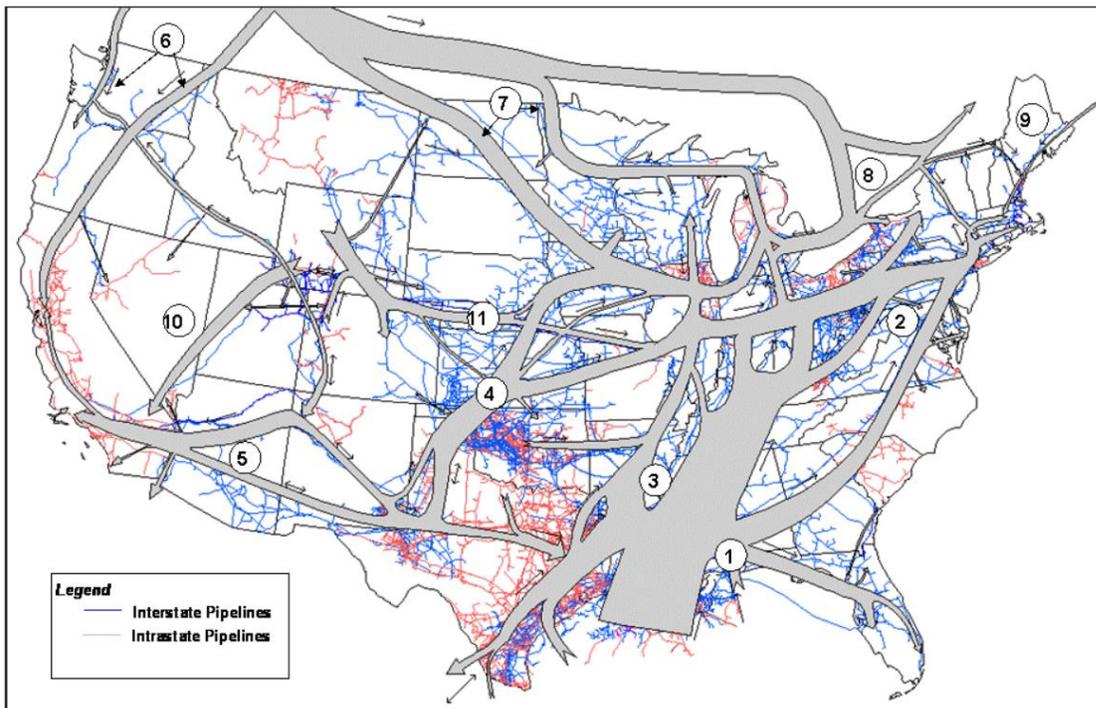


Figure 4.7: US Natural Gas Transportation Corridors⁶⁹

The EIA AEO2016 provides a forecast of net imports of dry natural gas as indicated in the following figure⁷⁰. Net imports are the sum of exports of gas from Western Canada and imports to Eastern Canada from the Marcellus/Utica Play. In 2015, Canada exported a net of 2 Bcf/day into the US; the EIA is forecasting that to drop to a small US import position by 2040.

⁶⁹ Source US Energy Information Administration (Oct 2008). EIA Natural Gas – About US Natural Gas Pipelines, 2008

⁷⁰ Source US Energy Information Administration (Oct 2008)

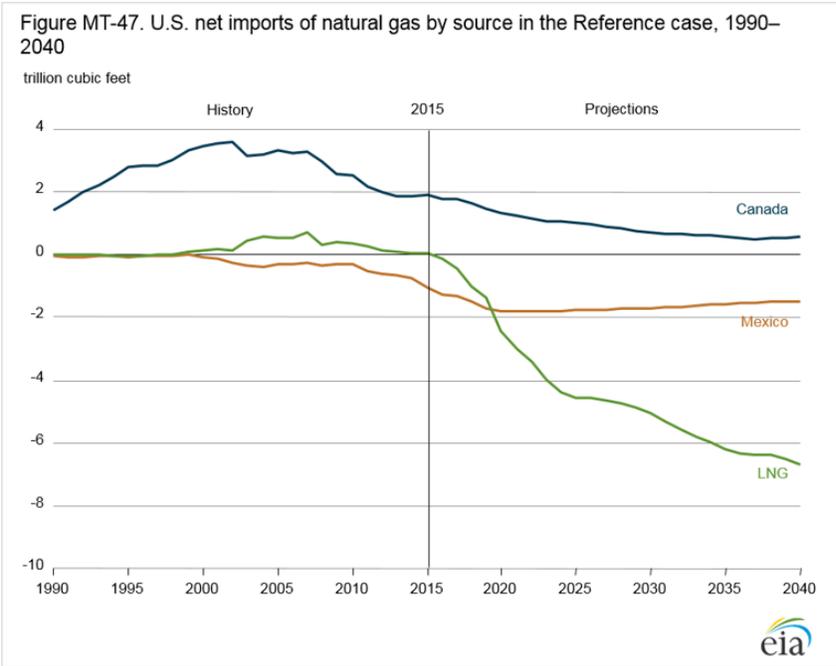


Figure 4.8: US Net Imports of Natural Gas⁷¹

Impact of Hydraulic Fracturing

One of the key technology advances that has impacted the supply and resulting price of natural gas has been the advent of long reach horizontal well drilling and multi stage hydraulic completions. These approaches have allowed the industry to produce natural gas (and oil) from tight conventional and shale formations that had previously been uneconomic to develop. These advancements have also triggered considerable discussion on the expansion of hydraulic fracturing and the impact that it could have on ground water supplies.

The EIA provides a historical analysis of marketed gas produced from hydraulically fractured wells and, in AEO2016, a forecast of dry natural gas production by gas type⁷². Currently about two thirds of total US marketed natural gas is produced from hydraulically fractured wells. We can gain further insight into the impact of hydraulically fracturing on the US natural gas supply by examining where the EIA forecast natural gas to be developed by gas type. In 2040, the EIA Reference Case forecasts that of the 42.1 Tcf/year of dry natural gas about 70% will be produced from shale gas or tight oil plays that require hydraulic fracturing to currently develop the resource⁷³.

⁷¹ Source US Energy Information Administration (Oct 2008). AEO2016 Market trends - Figure data - Figure MT-47. U.S. net imports of natural gas by source in the Reference case, 1990–2040 (trillion cubic feet)

⁷² Source US Energy Information Administration (Oct 2008)

⁷³Source US Energy Information Administration (Oct 2008)

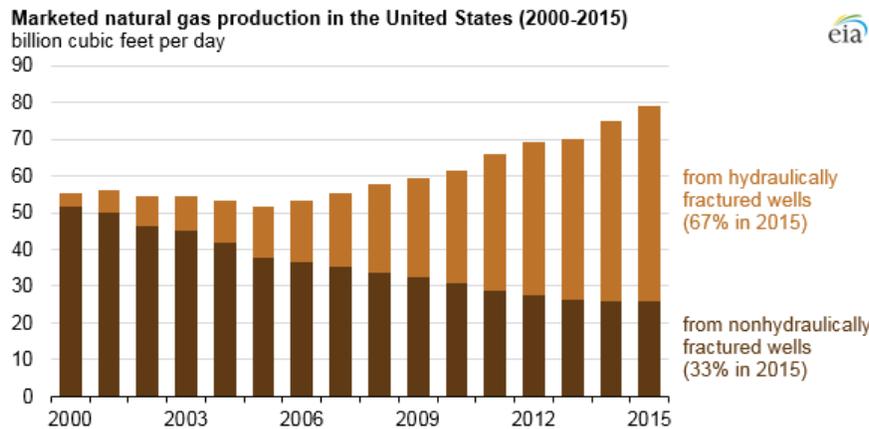


Figure 4.9: US Marketable Natural Gas from Hydraulically Fractured Wells⁷⁴

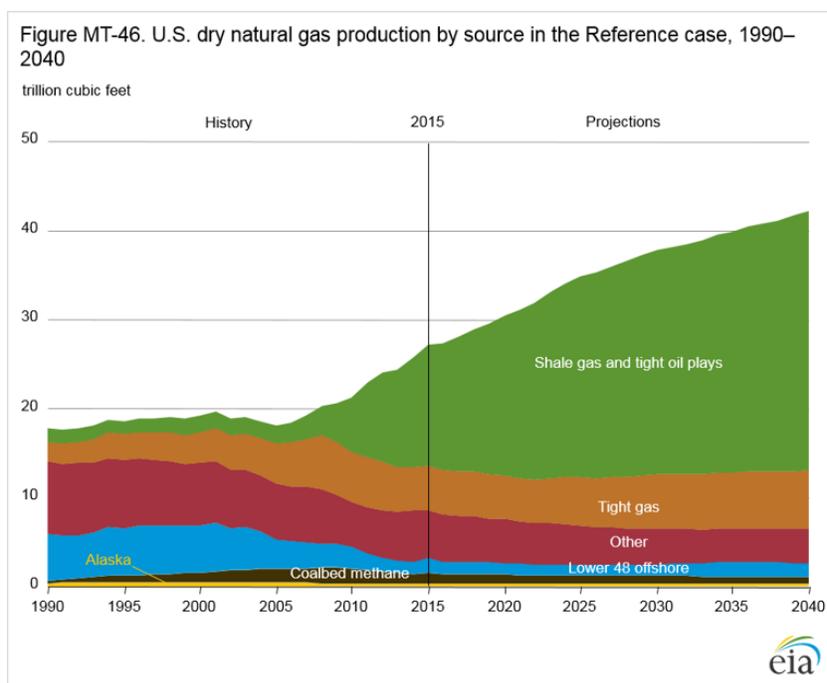


Figure 4.10: US Dry Natural Gas Production by Play Type⁷⁵

Within the US, the regulations that address well integrity and water protection are both federal (Public and American Indian Lands) and state (private and state owned lands). As a result, regulations vary and may continue to vary across the various jurisdictions. With the development of a high percentage of the natural gas supply currently dependent upon hydraulic fracturing, any changes to that practice (disallowing or curtailing hydraulic fracturing) could have a significant impact on the US natural gas supply. The assumption that similar regulatory changes would not be made in Canada could open up significant new demand for the export of natural gas in the US.

⁷⁴ Source US Energy Information Administration (Oct 2008). EIA Today in Energy May 5, 2016, Hydraulically fractured wells provide two-thirds of US natural gas production

⁷⁵ Source US Energy Information Administration (Oct 2008). AEO2016 Market trends - Figure data. Figure MT-46. U.S. dry natural gas production by source in the Reference case, 1990–2040 (trillion cubic feet)

US Natural Gas Resource Potential

As of Jan 1, 2013, the EIA estimates technically recoverable US dry natural gas resource at 2,767 Tcf. The accompanying table summarizes the type and location of that resource⁷⁶. Note that resources in other areas where drilling is officially prohibited are not included. At the 2015 dry gas production rate of 27.19 Tcf/year this represents a life of some 84 years.

Table 4.2: US Natural Gas Resource⁷⁷

Technically recoverable Dry Gas Resource (as of January 1, 2013) in Tcf	Proved Reserves	Unproved Resource	Total
Lower 48 Onshore ⁷⁸	287.3	1,392.0	1,679.3
Tight Gas	65.3	353.7	418.9
Shale Gas & Tight Oil	141.2	595.7	736.9
Coal Bed Methane	13.6	119.6	133.2
Other	67.4	323.0	390.4
Lower 48 Offshore	11.2	305.3	316.5
Alaska (Onshore and Offshore)	9.7	271.1	280.7
Total US	308.2	1,968.4	2,276.5

⁷⁶Source US Energy Information Administration (Oct 2008)

⁷⁷Source US Energy Information Administration (Oct 2008)

⁷⁸ The following Gas Types are included in the total

Section 5 - Canadian and United States Natural Gas Supply, Demand and Systems Comparison

The previous Sections 3 and 4 examined the natural gas resource, supply and demand in Western Canada and the US. When considering the performance of the systems as it relates to dependable and reliable supply for natural gas powered electrical generation there are significant similarities and some differences that could impact how those systems perform:

Similarities:

- Both the US and Western Canada have significant natural gas resources and productive capacity (absolutely and relative to demand).
- Productive capability is diverse and connected to the major demand areas by a network of sales gas pipeline systems.
- Geographically, the producing areas are located relatively near the demand centers in both the US and Western Canada.
- In Western Canada (as indicated in the following map⁷⁹), the main gas resource plays are the Montney (AB and BC), Deep Basin (AB and BC), Duvernay (AB) and the Liard, Horn River and Cordova Shale Gas Basins (BC).
- In the US (as indicated in the following map⁸⁰) the main gas resource holding states can be divided into three general areas; central (Texas, Oklahoma, Wyoming, Louisiana, Colorado and Ohio), northeast (Pennsylvania, West Virginia) and the Gulf of Mexico. The main natural gas demand is located in Texas, California, Louisiana, New York, Florida, Pennsylvania, Ohio, Michigan and New Jersey.

⁷⁹ From the NEB EF 2016 Energy Supply and Demand Projections to 2040

⁸⁰ Source U.S. Energy Information Administration (Oct 2008)

FIGURE 6.3

Key Producing Regions in the Western Canada Sedimentary Basin

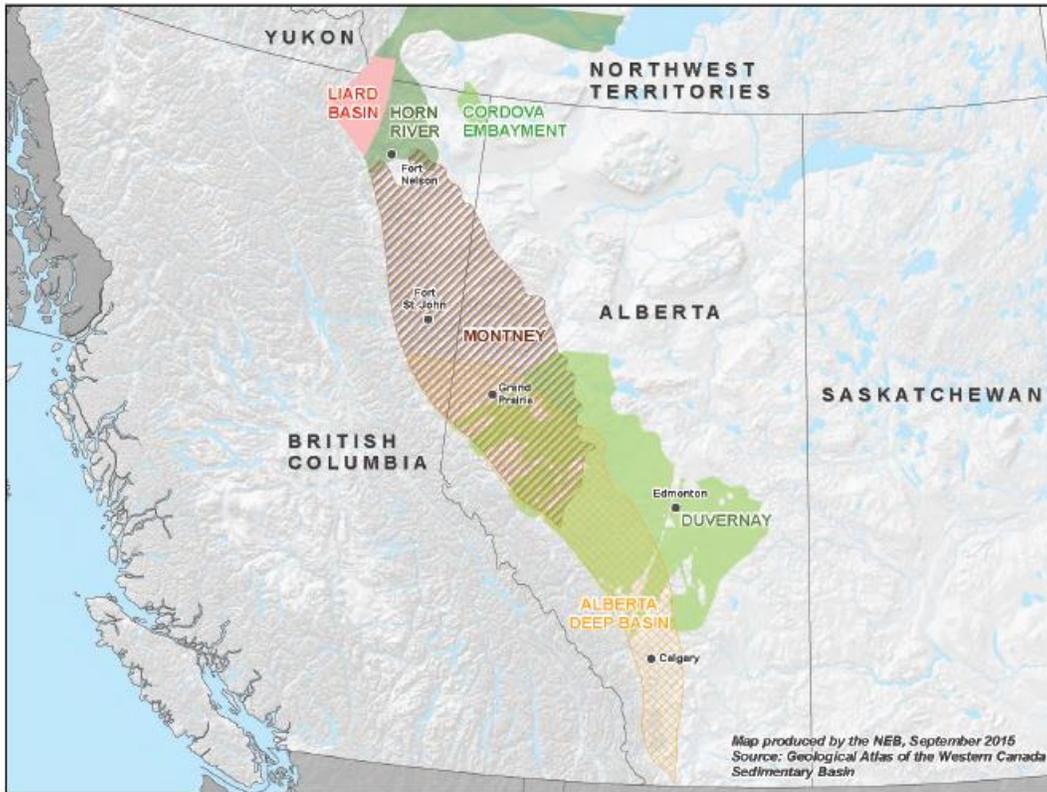


Figure 5.1: Key Natural Gas Growth Plays of Western Canada⁸¹

⁸¹ From the NEB EF 2016 Energy Supply and Demand Projections to 2040

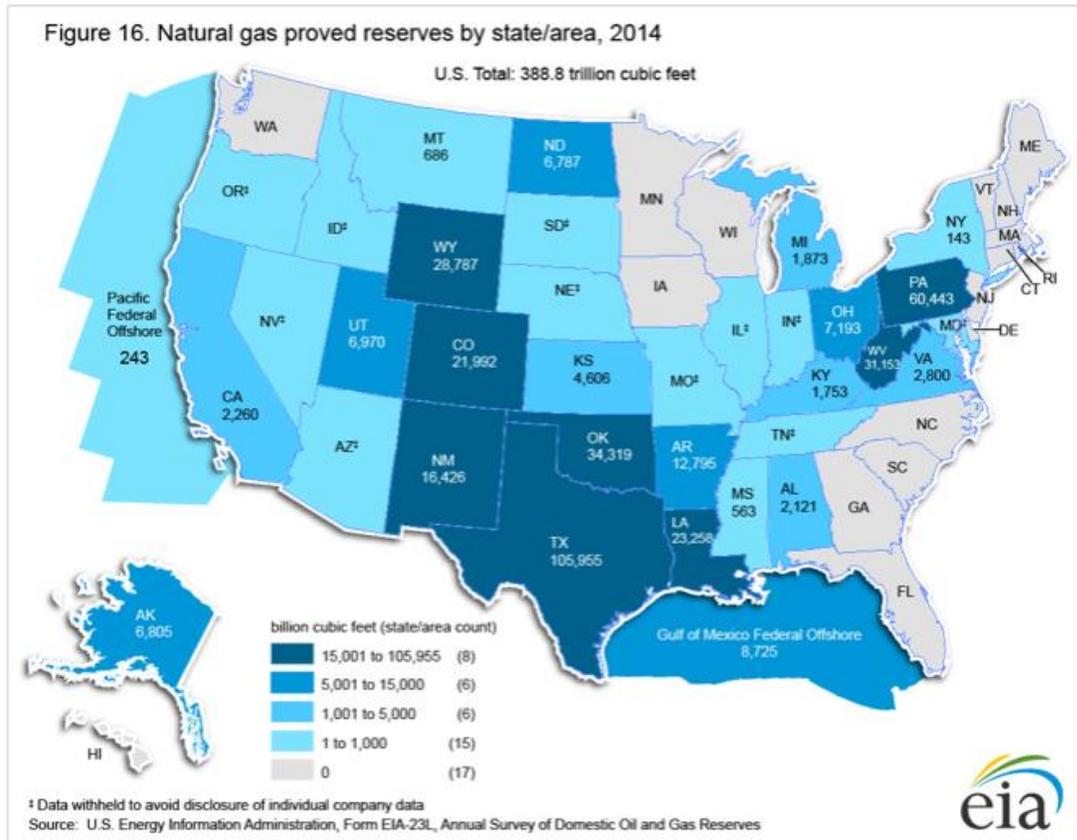


Figure 5.2: US Natural Gas Reserves by State⁸².

Differences:

- The distribution of the demand/consumption and the production of natural gas - The following map⁸³ shows the main interstate natural gas pipelines and the states where 85% of more of the natural gas consumed is delivered through the interstate pipeline network. The most current data available is for 2007 but should still be representative of the consumption and production patterns.
- The duplication of access paths to market - Western Canada has considerable redundancies built into the system that may not be present when a state is dependent upon gas supplies located out of state. This discontinuity does introduce a potential reliability risk that is not present in Western Canada.

⁸² Source U.S. Energy Information Administration (Oct 2008). US Crude oil and Natural Gas Proved Reserves, 2014

⁸³Source U.S. Energy Information Administration (Oct 2008)

Interstate Natural Gas Supply Dependency, 2007

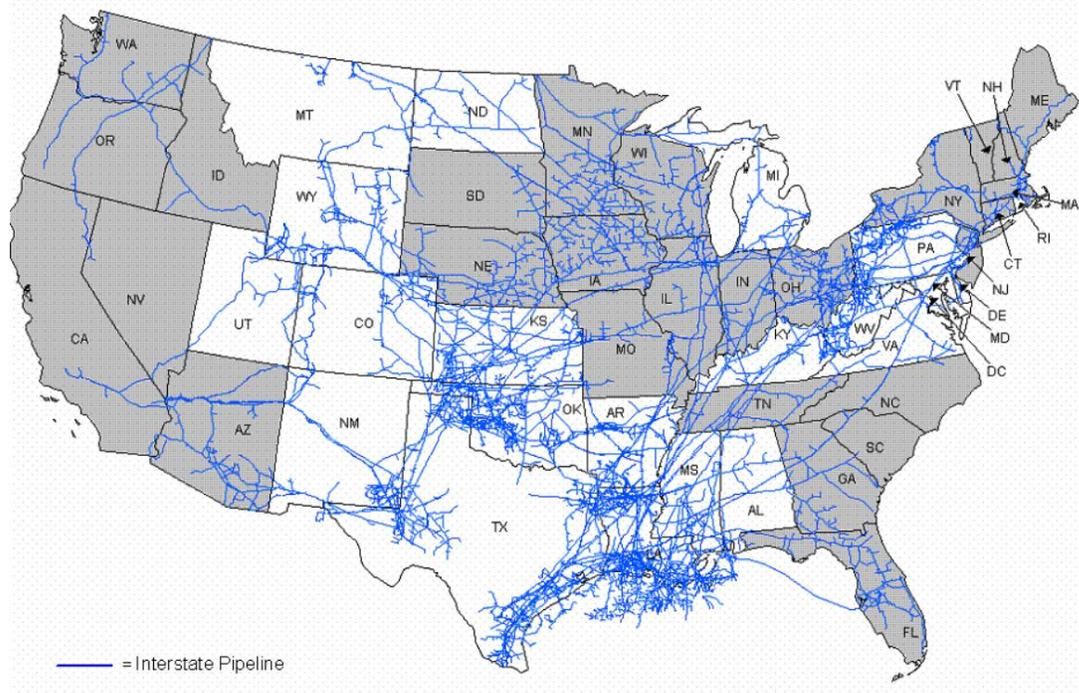


Figure 5.3: US Natural Gas Supply Dependency State⁸⁴

⁸⁴ Source U.S. Energy Information Administration (Oct 2008). EIA Natural Gas – About US Natural Gas Pipelines – Transporting Natural Gas

Section 6: Intra Alberta Sales Gas Systems

Summary of the Intra Alberta Natural Gas Transport Systems

There are three companies that operate essentially all of the pipelines that make up the Intra AB Natural Gas Transportation Systems; Nova Gas Transmission Limited (NGTL), ATCO and Alliance; two of the systems, Alliance and NGTL, also operate pipelines in BC:

- **Nova Gas Transmission Limited** - A wholly owned subsidiary of TransCanada, owns the largest system of pipelines in Western Canada spanning AB and, recently with expansions, into BC. The NGTL System (also referred to as NOVA) connects with other TransCanada operated pipelines and third party pipelines to supply natural gas to Intra AB and Eastern Canada markets and for export to the US.
- **ATCO** – The pipeline is part of the ATCO Group of Companies and is integrated with NGTL. From the shipper’s perspective, ATCO and NGTL are one pipeline system with a single point of contact for both systems. NGTL manages the overall planning functions for both companies. ATCO continues field operations of its system in coordination with NGTL.
- **Alliance** - A rich gas pipeline with receipt points in BC and AB that transports gas for processing at an Aux Sable facility outside of Chicago to recover liquids from the gas prior to the gas being sold in US Mid-West markets.

In addition, Westcoast (wholly owned by Spectra Energy) operates a fourth sales gas transportation system in BC. Spectra does not operate sales gas pipelines in AB but has interconnections with both the NGTL and Alliance systems that can deliver gas to or receive gas from the AB systems.

The following figure shows the main pipeline systems in Western Canada. For simplicity, the map only includes the portions of the NGTL System in the main supply growth areas (North West AB and North East BC) and the major demand growth area (North East AB Oil Sands).

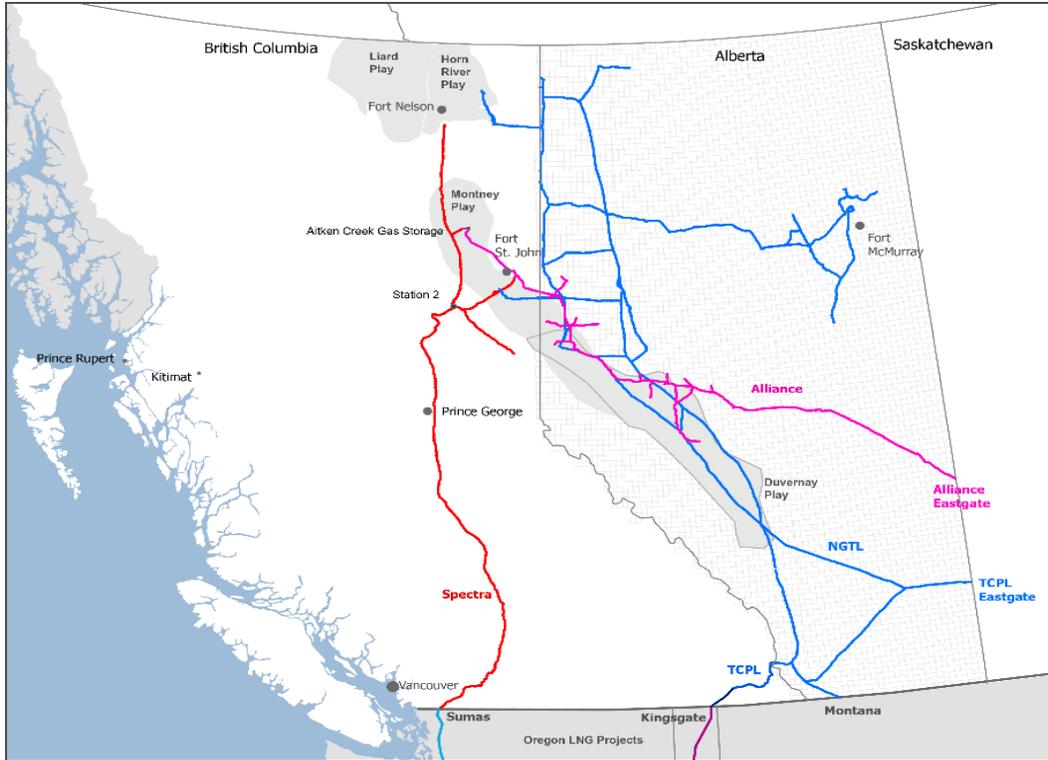


Figure 6.1: Major Western Canada Gas Transportation Pipelines⁸⁵

The following figure shows the combined NGTL and ATCO pipeline system in AB with an overview of the geographic coverage of the two systems; the NGTL System is shown in green and the ATCO System brown.

⁸⁵ Source: GPMi and Ziff Energy Gas West for LNG Growth - Western Canada Gas Supply & Infrastructure Study – December 2014

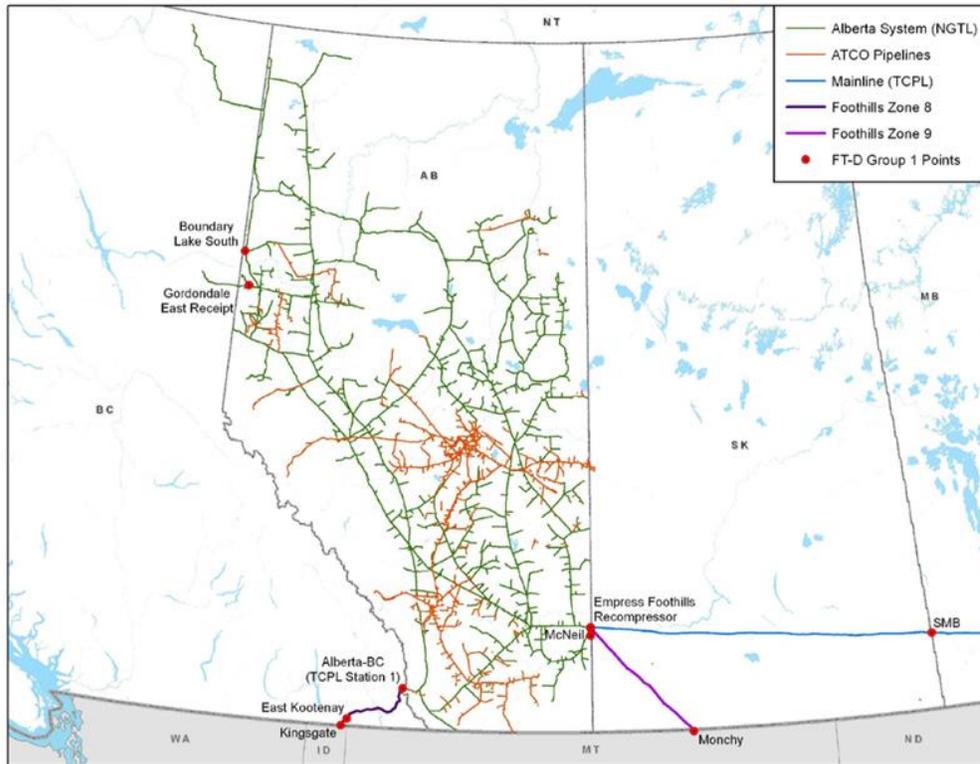


Figure 6.2: NGTL and ATCO Gas Transportation Pipelines⁸⁶

The NGTL System Segments Codes and Project Areas September 2016 map⁸⁷ on the NGTL website included in the footnote will be used as a reference in the following sections of the report where additional detail of the system is required.

System Design, Operation and Focus

The combined NGTL and ATCO System is by far the most extensive gas transportation system in AB and Western Canada. It is an interconnected system of 24,500 km (15,250 miles) of pipelines with over 1,100 receipt points and 380 delivery points. The system allows gas received by the pipeline (receipt point) to exit (delivery point) anywhere on the system, provided there is sufficient physical capacity for both receipt and delivery of the gas. It should be noted that the NGTL and ATCO systems are commercially and operationally managed as an integrated system.

The NGTL System is the main pipeline system delivering gas to Intra AB markets and to markets outside of AB via connections with the TransCanada Eastern Canadian Mainline and Foothills pipelines as well as third party systems. NGTL's recent focus has been to provide pipelines to deliver growth volumes from North East BC and North West AB to proposed Liquefied Natural Gas (LNG) facilities on the west coast of BC (the Kitimat and Prince Rupert areas) and to provide gas volumes to support the Oil Sands Projects in North East AB.

⁸⁶ Source NGTL maps – Bing image

⁸⁷ http://www.transcanada.com/customerexpress/docs/fh_system_maps/ab-system-map-segments-sept2016-final.PDF

The ATCO system is an Intra AB System and is integrated with the NGTL System. The focus of the ATCO system is to supply gas for residential and commercial markets in AB.

The Alliance pipeline is a high pressure dense phase 2,980 km (1,860 mile) “bullet” pipeline with 42 receipt points in AB and BC and 11 delivery points in the US Mid-West. This system accesses gas markets in the US Mid-West and provides an alternative method to transport Natural Gas Liquids (NGL’s) from Western Canada for markets in the Chicago area.

The Spectra system gathers gas from gas processing facilities in northern BC for delivery to several distribution pipelines that deliver gas to residential and commercial markets in BC. Gas in excess of BC’s needs is exported to US markets (Seattle, Washington) at Sumas BC.

The following table provides a summary of pipeline sizes and maximum operating pressures (MOP) for the four systems that transport gas in Western Canada. The pipeline sizes and pressures are typical for the mainline segments of the systems that transport larger volumes of gas and do not include the smaller lateral pipelines that gather gas from individual or groups of receipt points or to Intra AB delivery points. In general, the main NGTL and Spectra pipeline corridors have more than one pipeline in parallel.

Table 6.1: Pipeline Size and Maximum Operating Pressure

System	Pipe Outside Diameter Range (OD - Inches)	Maximum Operating Pressure Range (Psi)	Comments
NGTL			
Edson Mainline	30 to 48	935 to 1260	Edson to James River – four parallel pipelines
West AB Mainline	36 to 48	845 to 1260	James Rover to AB/BC border – two or three parallel pipelines
Central and Eastern Mainline	30 to 48	826 to 1260	James River to AB/SK border – four or five parallel pipelines
ATCO			
	8 to 10	300 to 1440	Majority of the ATCO larger pipelines are surrounding Edmonton and Calgary
	12 to 24	300 to 1230	60% of the 8 inch and larger pipelines are 12, 16, or 24-inch diameter
Alliance			
	36 to 42	1740	Canadian Mainline
	36	1935	US Mainline
Spectra			
	30	935	Fort Nelson to Station 2 – two parallel pipelines for most of the length
	30 and 36	935	Station 2 to Kingsvale – two parallel pipelines

As the purpose of each main pipeline system is different, the pipeline size distribution and operating pressure of each system is also different and tailored towards the service that the specific system provides. The ATCO system is designed to distribute gas to end users and its pipelines typically operate at lower pressure and are of a smaller diameter. The Alliance system is a single pipeline designed to transport gas rich in NGL components from North East BC and AB receipt points to the Chicago area and the pipeline is larger in diameter and operates at a higher pressure. The NGTL system is the most extensive system and has been continually modified over the years, resulting in the addition of parallel pipelines (loops) in many areas as supply and market demand grew.

Pipeline Costs and Delivery Capacity

The following table provides cost estimates that NGTL has developed for recent projects⁸⁸, normalized cost information for various pipeline projects and a commonly used rule of thumb method to estimate pipeline costs. The table summarizes the cost for 15 pipelines from 20 inch to 48 inch with various lengths and provides a reasonable method to estimate costs for other pipeline projects using the average factor of \$233,000/diameter-inch-mile. NGTL has a substantial base of historical projects to estimate costs therefore this factor should be reasonable to estimate other pipeline projects of comparable size, length, operating pressure and gas characteristics. Pipeline costs vary considerably depending on a variety of factors including: terrain, river crossings, stakeholder issues, etc. Therefore, caution must be used when extrapolating these estimated costs to other system design parameters.

Table 6.2: Estimated Pipeline Costs

Pipeline Project	Pipe OD (Inches)	Pipe Length (miles)	Investment (\$MM)	Normalized Cost (\$/dia-inch-mile)
2015 Annual Plan				
Hythe Lateral Loop No. 2	20	8.125	41	\$252,308
Cutbank River Lateral Loop No.2	24	11.25	65	\$240,741
North Central Corridor Loop	48	20	200	\$208,333
Western AB Mainline Loop	42	20.625	240	\$277,056
Appendix E 2016 Facility Status Update (September)				
Calgary UPR (AP)	20	11.875	75	\$315,789
Edmonton APR (AP)	20	5	35	\$350,000
Grande Prairie Mainline Loop No. 2	48	22.5	228	\$211,111
Inland Looping (AP)	20	11.875	42	\$176,842
Kettle River Lateral Loop	24	12.5	77	\$256,667
Liege Lateral Loop No. 2 (Pelican)	30	35	233	\$221,905
North Montney Mainline (Kahta)	42	74.375	530	\$169,668
Northwest Mainline Loop No. 2	36	16.875	116	\$190,947
Northwest Mainline Loop Boundary	36	56.875	442	\$215,873
Cutbank River Lateral Loop No. 2	24	20	92	\$191,667
Pembina Expansion	24	12.625	66	\$217,822
Average				\$233,115

Pipeline Capacity

NGTL operates many pipelines and has significant history to develop accurate methods to estimate capacity of their pipelines. Appendix 5⁸⁹ of NGTL's Guidelines for New Facilities shows the capacity of various pipeline diameters and the assumptions used to determine the flowrates. The capacities are based on pipelines 30 Km (18.6 miles) long with inlet pressure of 8,450 kpa (1,225 psi)⁹⁰. Other assumptions on gas quality and flowing characteristics are also listed in Appendix 5 of that NGTL Guideline.

⁸⁸ Source: NGTL 2015 Annual Plan and Appendix 2, 2016 Facility Status Update (September)

⁸⁹ http://www.transcanada.com/customerexpress/docs/ab_industry_committee_ttfp/Guidelines-for-New-Facilities.pdf

⁹⁰ This is the highest practical pressure in the NGTL system based on the Maximum Operating Pressure (MOP) of 1260 psi in segments of their system. Table 6.1 shows that portions of the system have MOPs as low as 826 psi.

The NGTL data was used to correlate to publicly available capacity calculation methods in order to determine capacity sensitivity at different pressures. The publicly available CheCalc⁹¹ approach to Natural Gas pipeline sizing was used for this analysis. There are also many other methods available. A reasonable match was obtained using the assumptions in the NGTL Appendix 5 and the CheCalc method for the same criteria. As a result, the CheCalc method was used to determine pipeline capacities at lower pressures than used by NGTL in the samples included in Appendix 5 of the NGTL Guidelines for new facilities.

With pipeline capacities determined, the power generated in MW's by the volume of gas for each pipeline size was determined by using the factor of 7.5 GJ of gas required to generate an MWhr of electric power. This factor assumes an efficient natural gas fired power generation system will be developed. If a lower efficiency is assumed, a higher volume of gas to generate the same quantity of power will be required.

The following figure shows several sizes of pipelines commonly used on the NGTL system and their ability to deliver the gas required to produce the equivalent quantity of electric power.

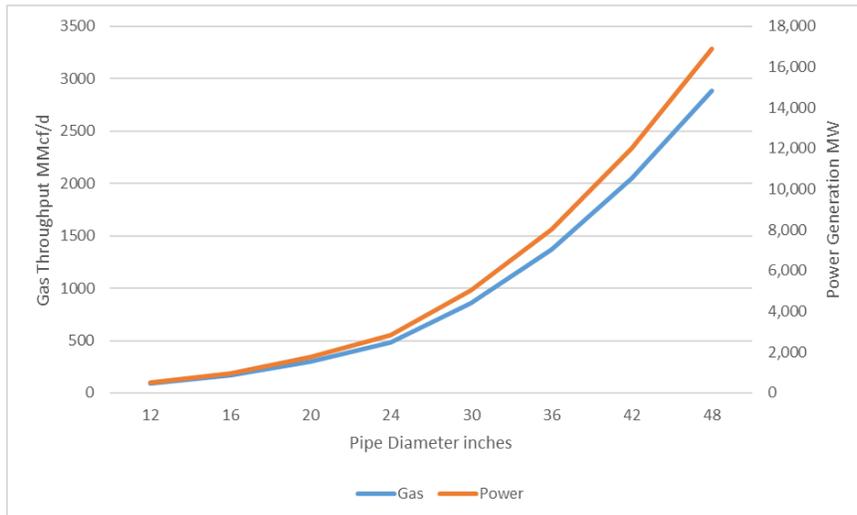


Figure 6.3: Pipeline throughput and Equivalent Power Generated

The following figure and table show the impact of lower operating pressures on the ability of pipelines to deliver gas for power generation.

⁹¹ Chemical Engineering Calculations - cheCalc.com/solved/gasPipeSizing.html

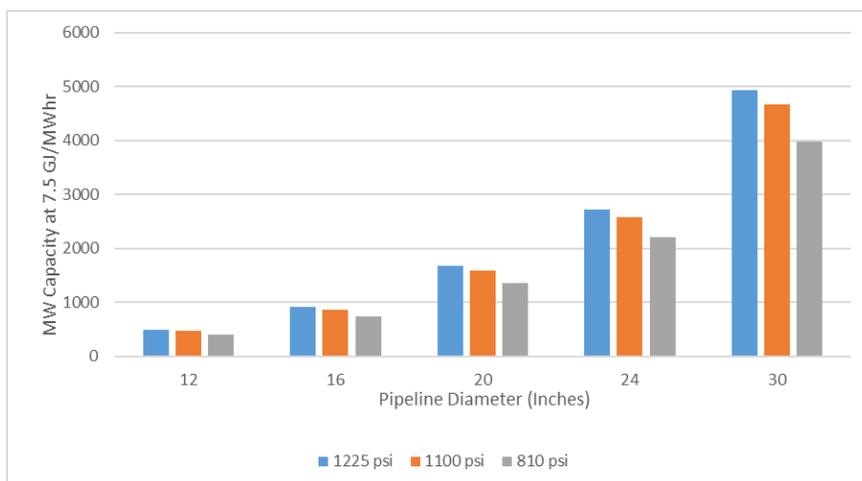


Figure 6.4: Pipeline Operating Pressure Impact on Capacity

Table 6.3: Pipeline Operating Pressure Impact on Capacity

Pipe Size (inches)	MW of Electrical Power Generation - Operating Pressure (Psi)		
	1,225	1,100	810
12	492	469	398
16	920	867	738
20	1,676	1,588	1,353
24	2,724	2,584	2,203
30	4,939	4,675	3,984
36	8,003	7,575	6,450
42	12,010	11,365	9,684
48	17,048	16,128	13,744

Gas Transportation System Modifications Development Process

For purposes of the following analysis, the focus is on the NGTL System as it is the system that is most likely to supply gas to proposed gas fired power generation projects to replace coal fired power generation. Alliance and Spectra have similar processes.

The NGTL system is very complex due to the large number of receipt and delivery points and the interconnectivity of pipelines within the system. Over the years, a sophisticated procedure has evolved to manage the system and develop solutions for customer driven requests for receipt and delivery services.

The process is initiated by customer requests for new or modified receipt or delivery requirements, NGTL’s internal review of these requests, and system supply and demand forecasts. This information is assembled into an annual plan that includes gas with signed firm service agreements. NGTL then completes a detailed system design and lateral review. Once the annual plan is approved, the project specific regulatory applications are made and projects to implement the required modifications and or new facilities are carried out. This process can take up to 2 to 3 years (or longer) to complete as the NGTL process is very rigorous and obtaining the regulatory and stakeholder approvals can be time consuming.

Components of the process include:

- **The Tolls, Tariff, Facilities & Procedures Committee (TTFP)** - This committee is the main forum for communicating system wide issues between NGTL and shippers on the system. A subcommittee, the standing Facilities Task Force (FTF)⁹² is responsible for issues arising from TTFP priorities regarding facility planning and policy issues.
- **The Annual Plan** - NGTL develops an Annual Plan that is discussed with the TTFP members and made available on their website for use by customers and other interested parties. The December 2015 Annual Plan is referenced in this analysis. The plan describes the system wide modifications expected to be initiated during the next Gas Year as a result of customer requests for Firm Service on the system. The Gas Year is defined as being from November 1 through to the following November 1 of a given year. The Annual Plan also provides NGTL's design forecast (generally prepared about 6 months prior to developing the Annual Plan) and other information to assist in planning for system changes. The Annual Plan is updated after its release to include subsequent service requests and modifications. Refer to the following links for additional details^{93,94}.
- **Facilities Design Documents** - NGTL has developed several documents to provide guidelines for the development of new or modified facilities to connect new receipt and delivery points. The Facilities Design Methodology Document (FDMD)⁹⁵ describes the geographic planning areas used to determine design forecasts and the process used to implement changes. Figure 4⁹⁶ of this document provides a flow chart for the Facility Design Process. A key component of this process are the Customer Service Agreements for Firm Service on the system that must be in place before the requested service can be included in the overall Facility Plan.
- **Report of the Guidelines for the New Facilities Task Force**⁹⁷ – A companion document, with the most recent revision dated October 18, 2011, provides additional details concerning the management, construction, ownership and operation of receipt and delivery modifications for new connections. These guidelines generally follow the concept to differentiate what modifications can be rolled into the system toll calculation and what modifications must be absorbed by the company requesting the new or modified receipt or delivery point service. In general, modifications that only benefit the customer requesting the service, are not rolled into the system tolls. Each project is reviewed separately.

Customer requests for a new or modified service on the NGTL system are initiated by completion of either a NGTL AFS Delivery or Receipt Form. This request is evaluated by NGTL as part of the Annual Plan to determine modifications to receive or deliver the new volumes and any modifications required to the

⁹² http://www.transcanada.com/customerexpress/docs/ab_industry_committee_ttfp/TTFP-Procedures.pdf

⁹³ https://www.google.com/url?q=http://www.transcanada.com/customerexpress/docs/ab_regulatory_filings/2015_Annual_Plan_December_15_2015_final.pdf&sa=U&ved=0ahUKEwiZnanQj-rPAhWn5oMKHUb0AzgQFggNMAQ&client=internal-uds-cse&usg=AFQjCNHHDTvQAPVEyoR1erqnfz4akDuxHA

⁹⁴ http://www.transcanada.com/customerexpress/docs/ab_regulatory/appendix-2-annual-plan-2016.pdf

⁹⁵ http://www.transcanada.com/customerexpress/docs/ab_regulatory_facilities/Facilities-Design-Methodology-Document.pdf

⁹⁶ Figure 4 is found on page 26 of the FDMD document

⁹⁷ http://www.transcanada.com/customerexpress/docs/ab_industry_committee_ttfp/Guidelines-for-New-Facilities.pdf

existing system downstream of receipt points or upstream of delivery points to ensure the system is capable of transporting the gas requested. Existing system modifications will also take into account other customer requests made during the planning period that impact the affected portion of the NGTL system and other system changes that result from the NGTL review of the system to meet overall forecast volumes⁹⁸.

Potential Impact of West Coast British Columbia LNG Plants on the NGTL System in Alberta

There has been significant gas development activity in North East BC and North West AB at least partially stimulated by the proposed LNG projects. More than a dozen LNG projects are in various stages of development or approval.

Gas Transportation System to Deliver Gas to LNG Facilities

There is only one small diameter pipeline that currently accesses the west coast ports where the majority of the LNG plant capacity has been proposed (Kitimat and Prince Rupert). This pipeline receives natural gas off the Spectra System and currently transports gas for residential and commercial customers and does not have the capacity for supplying any of the large LNG facilities that have been proposed.

The following figure⁹⁹ shows the pipelines that have been proposed to deliver gas to the West Coast LNG facilities.

⁹⁸ http://www.transcanada.com/customerexpress/docs/NGTL_AFS_Delivery_APR2015.pdf
http://www.transcanada.com/customerexpress/docs/NGTL_AFS_Receipt_APR2015.pdf

⁹⁹ Source: GPMi and Ziff Energy Gas West for LNG Growth - Western Canada Gas Supply & Infrastructure Study – December 2014

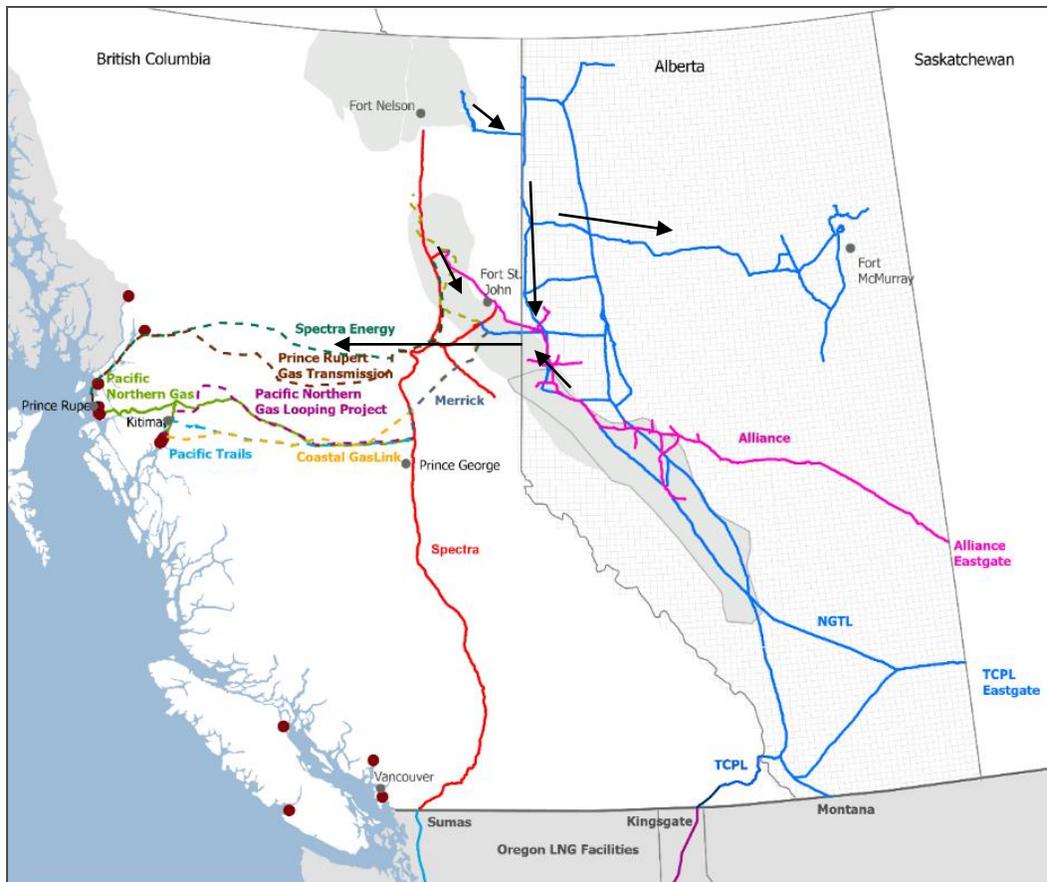


Figure 6.5: Proposed Pipelines to West Coast LNG Facilities¹⁰⁰

The following tables^{101 102} provide preliminary design details for the pipelines proposed to deliver gas to West Coast LNG facilities.

Table 6.4: Proposed Northeast BC Interconnect Pipelines

System Name	Operator and Owners	Associated LNG Project	Permit Status	From/To	Initial Design Capacity, Bcf/d	Expanded Capacity, Bcf/d	Pipe OD, inches	Pipeline Length, miles
Merrick Pipeline	NGTL	KM LNG	NEB Application Pending	Groundbirch to Summit Lake	1.9	3.6	48	160
North Montney Mainline	NGTL	Pacific Northwest LNG	NEB Application filed	Aitken Creek to Groundbirch ¹⁰³	2.4	None announced	42	187

¹⁰⁰ Source: GPMi and Ziff Energy Gas West for LNG Growth - Western Canada Gas Supply & Infrastructure Study – December 2014

¹⁰¹ Source: GPMi and Ziff Energy Gas West for LNG Growth - Western Canada Gas Supply & Infrastructure Study – December 2014

¹⁰² Source: GPMi and Ziff Energy Gas West for LNG Growth - Western Canada Gas Supply & Infrastructure Study – December 2014

¹⁰³ Connections to proposed Prince Rupert Transmission pipeline project to Prince Rupert

Table 6.5: Proposed Prince Rupert/Kitimat Feedstock Pipelines

System	Operator and Owners	Associated LNG Project	Permit Status ¹⁰⁴	From/To	Initial Design Capacity, Bcf/d	Expanded Capacity, Bcf/d	Pipe OD, inches	Pipeline Length, miles
Westcoast Connector Gas Transmission ¹⁰⁵	Spectra Energy and BG Canada ¹⁰⁶	Prince Rupert LNG	Under Review	Cyprus Area to Ridley Island	4.2	Second parallel pipeline 8.4	Land sections 48 Marine sections 42	525
Prince Rupert Gas Transmission ¹⁰⁷	TransCanada Pipelines	Pacific Northwest LNG	Under Review	Hudson's Hope to Lelu Island	2.0	3.6 total	Land sections 48 Marine sections (2) 36	560
Pacific Northern Looping Project	Pacific Northern Gas	Multiple Proposed	Pre-Application	Summit Lake to Kitimat	0.6	N/A	24	330
Pacific Trail Pipeline	Pacific Northern Gas	Kitimat LNG	Certificate Extension	Summit Lake to Bish Cove	4.0	N/A	42	290
Coastal GasLink	TransCanada Pipelines	LNG Canada	Certificate Issued	Groundbirch to Kitimat	1.8	3.6 total	48	400

The impact of LNG projects on the NGTL System depends on assumptions as to when the LNG export projects will mature, what projects are developed and where the gas will be sourced. To that end, we have assessed two goal post scenarios primarily related to the timing of the proposed projects.

Assume LNG Projects Proceed in the Near Future

In this scenario, the supply of gas to the LNG plants will likely have minimal impact on all but the extreme North West portion of the NGTL system in AB¹⁰⁸.

Initially it is expected that the majority of the gas that will be re-directed to West Coast BC LNG will be from the North Montney play that is well established in BC. Depending on the volume of gas required and the supply arrangements of the owners of the specific LNG project, the Groundbirch Mainline and Gordondale Lateral (GRDL) that currently flow west to east into AB will be reversed and flow gas to the west coast. As additional projects are developed, gas from the Liard and Horn River areas will flow east through an existing NGTL lateral and south on the North West Mainline (NWML), to the Saddle Hills Compression facility and then west through the Gordondale Lateral and Groundbirch Mainline to connect to proposed pipelines to the LNG facilities¹⁰⁹. Timing and volume of gas flowing down this system will depend on development plans by the LNG participants with gas in the Liard and Horn River areas and overall system dynamics. Gas from the NWML and GRDL areas on the NGTL system are likely

¹⁰⁴ Status obtained from BC Environmental Assessment Office website October 26, 2014.

¹⁰⁵ Data source; Environmental Assessment Certificate Application March 2014 and Spectra Energy Website.

¹⁰⁶ BG has announced that their LNG Export Plant has been deferred.

¹⁰⁷ Application for an Environmental Assessment Certificate Revision, 1 May 2014, Part A.

¹⁰⁸ Refer to NGTL System - Segment Codes and Project Areas - September 2016 - segment 4 GRDL of the Peace River Project Area

¹⁰⁹ Refer to NGTL System - Segment Codes and Project Areas - September 2016 - segment 3 NWML of the Peace River Project Area

to also flow east to the Oil Sands areas. NGTL has already completed modifications to the system to allow flow in both directions on portions of the North West Mainline system down to the Saddle Hills Compression Facility to direct gas to the Oil Sands Projects or south to the main system. Currently gas flows north and then east to the Oil Sands Area.

Impacts on the majority of the NGTL System in AB will not be felt until a significant number of LNG projects proceed. This will require additional facility modifications later in the forecast period. A “balance point” will occur on the mainline north of the James River junction that will allow flow to the north and west for LNG or south and east for traditional markets¹¹⁰ depending on the relative flows west or east. Physical flow of gas will also be impacted by commercial trades and swaps on the system.

The black arrows on Figure 6.5 show the generalized flow patterns as gas supply to LNG projects increases.

Assume LNG Projects are Delayed

Currently there is more developed or developable gas supply in Western Canada than there is demand. This together with uncertainty of the viability and timing of the LNG projects is significantly impacting the future of the natural gas industry in Western Canada. With deferral of LNG projects and limited growth of local gas markets, the only outlet for the developing gas in the growing Peace River Project Area is movement south and east on the NGTL system to Eastern Canada and export to the US or to export points south on the Spectra system. Both of these systems are currently capacity constrained.

With limited or no flow west to LNG facilities, the Gordondale Lateral and Groundbirch Mainline will continue to flow east. Additional flows will also be supplied from new or larger connections from the Spectra System. This will put additional pressure on the existing NGTL System in AB, predominantly upstream of James River.

Historically, flows on the main lines in segments from Edson to James River (CENT) and the main lines downstream of James River to the Saskatchewan Border have been greater than current flows, therefore the system is potentially capable of flowing more gas than current rates. There will need to be modifications to the system to re store the previous capacity. For example, the design capability of the segment from Princess to Empress/McNeill (EGAT) is currently 4 Bcf/d¹¹¹, compared to 7 Bcf/d¹¹² in 2012 when demand for export gas was higher than it is today.

¹¹⁰ Refer to NGTL System - Segment Codes and Project Areas - September 2016 - likely in segment 7 GMPI of the Peace River Project Area

¹¹¹ System Utilization Monthly Report for month ending August 2016

¹¹² System Utilization Monthly Report for month ending August 2012

Section 7 Intra Alberta Natural Gas System Reliability

The reliability of the delivery system to supply gas for large scale power generation is critical. Gas supply assurance is dependent upon three main factors: supply (ultimately resource) availability, capacity of the infrastructure to deliver the required supply and the reliability of that infrastructure to deliver the available resource. This section of the report deals with reliability of the gas delivery system.

Uninterrupted supply to gas fired power generation facilities is a function of the capacity of the system that delivers gas to the specific generation site, the reliability of the segments of the delivery system and redundancies available to support gas delivery when operational problems occur. The total gas supply system is composed of two main segments:

- The upstream segment including the wells, gathering pipelines, field compression facilities and centrally located gas processing plants that condition the gas from the reservoirs and deliver sales gas to the transportation pipeline systems.
- The downstream portion including the transportation pipelines, compression, storage facilities and distribution pipelines that receive the conditioned gas at the gas processing plant or field facility outlets (receipt points) and transport the gas to various Intra AB or export markets (delivery points).

The following figure shows a simplified schematic of the delivery system.

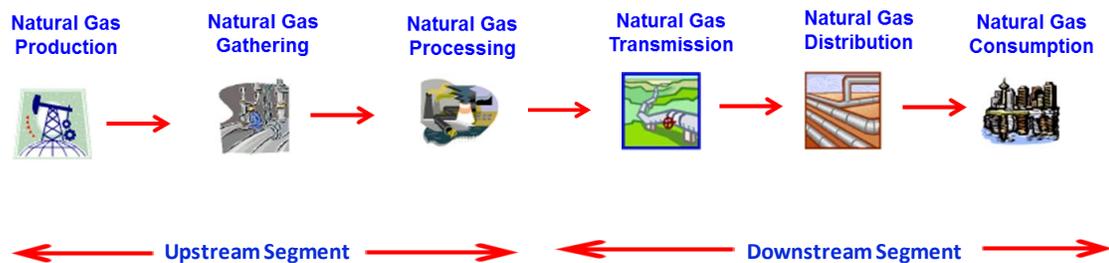


Figure 7.1: Schematic of Gas Delivery System¹¹³

Upstream Segment

The upstream segment of the system includes approximately 575 active gas processing plants operated by over 100 different companies ranging in size from less than 1 MMcf/d to over 700 MMcf/d^{114,115} of capacity. Total capacity of the active gas processing plants is 30 Bcf/d with average utilization of slightly less than 40%. Each of the 575 gas processing plants and associated gathering and compression facilities operate essentially independent of each other with the exception of connection to the power grid and liquids take away pipelines in some locations. Therefore, an outage at a specific processing facility or supporting gathering and compression infrastructure is not likely to impact the operation of the remaining processing facilities and does not significantly impact downstream delivery points remote from the specific upstream facilities.

¹¹³ Source GPMi Presentation - Western Canada NGL 101

¹¹⁴ Excludes the straddle plants that reprocess gas at the AB borders for delivery to export markets

¹¹⁵ Source: GeoScout data base

Downstream Segment

The major transportation and compression infrastructure and portions of the distribution system are operated by NGTL and ATCO. Storage facilities are operated by private entities. Several local distribution companies connect to the NGTL and ATCO systems and also distribute gas to consumers. Figure 6.2 on page 44 (in Section 6) shows a schematic of the NGTL and ATCO transportation system. The system has many points where pipelines inter connect which provides significant flexibility to flow gas along alternative flow paths in the event of an outage in any one section. In addition, there is redundancy provided by parallel pipelines in many areas and multiple compressors at many locations allowing gas to flow at reduced rates if one pipeline or compressor is shut down for maintenance or other reason. The significant number of independent upstream processing facilities plus the flexibility of the transportation system provides a very high overall system reliability which has been demonstrated over the years.

NGTL provides a monthly update of system utilization and system capability on their web site. The report for August 2016 is included in the link below¹¹⁶.

Page 7 of that August report shows the Current Throughput vs. Design Capability of the NGTL transportation pipeline system upstream of the James River junction (located about 10 miles north of Sunde, AB). This section of the system is under the greatest capacity stress due to increasing receipt point requests to transport developing production primarily from the Montney play in North East BC and North West AB. The chart shows that the system is operating essentially at current design capability with actual throughputs fluctuating within a narrow band of capability. These throughput fluctuations are as the result of:

- The rise and fall of market demand.
- Upstream receipt point shortfalls due to outages.
- Transportation system operational variations including line pack¹¹⁷ and weather changes and planned or unplanned outages on the NGTL system.

This chart is typical of charts for each section of the NGTL system, however each section has different flow vs capability characteristics.

An additional region of capacity stress is the Lake Wabamun area west of Edmonton. In this instance, it is the shortness of additional delivery capacity as market participants assess the value of converting coal-fired generators to natural gas.

Causes of Transportation System Outages

Planned System Outages

Pipeline companies have sophisticated preventative maintenance and asset integrity programs. These programs use historical operational data to develop annual programs to carry out compressor and pipeline maintenance, make necessary repairs, meet regulatory requirements, assess the condition of facilities and reduce unplanned outages.

¹¹⁶ http://www.transcanada.com/customerexpress/docs/ab_operations_planning_system_utilization/August_2016.pdf

¹¹⁷ Line pack is the volume of gas in the pipeline system at any given time. For example, on November 4, 2016, line pack volume was 16,500 MMcf/d. Line pack varies over time depending on operating pressures, receipt rates and delivery rates.

NGTL utilizes several methods to update customers as to the status of their system and planned outages to implement pipeline integrity programs and preventative maintenance programs. To the extent possible, planned outages are coordinated with shippers and integrated into the overall program. The methods NGTL uses to coordinate and communicate planned outages are described in documents including the Monthly Outage Forecasts and meetings such as the NGTL System and Foothills Pipeline Customer Meetings.

The table at the end of the Monthly Outage Forecast for October ¹¹⁸ provides an estimate of where outages are required, outage durations and timing of the outages for the next 12-month period. Typical duration of outages is less than a week however larger projects can result in longer durations. The majority of the outages are restrictions in flow not complete curtailments.

Slides 8 and 9 of the NGTL System and Foothills Pipeline Customer Meeting for September 22, 2016¹¹⁹ provides a summary of the long term, short term and imminent outage notification methods used to communicate with customers.

Power Failure

Power supply failures do not have a significant impact on the downstream pipeline transportation system as major compressors are generally operated on natural gas taken off the system. Power failures can impact upstream gas processing facilities that rely on power to operate. Depending on the extent of the power failure and the location of the delivery points, these power failures can impact delivery point reliability. In areas where power is unreliable or not economic to tie into the power grid, processing facilities generate their own power supply and reliability of external power supply is not a factor. Most facilities have emergency backup power, however larger facilities that depend on power supply from the grid to operate generally do not have backup power sufficient to maintain full operations.

Unplanned outages

The complexity of the NGTL receipt and delivery system makes it difficult to determine the impact of a failure of a component of the supply infrastructure on a specific delivery point without knowledge of the specific delivery point location. However, in general, a failure in the upstream segment of the system will have minimal impact on a delivery point downstream of and remote from the outage. Unless the delivery point is near the point of failure, the downstream segment of the system has sufficient flexibility to react to the shortage of gas supply to rebalance and restore the system supply. The system line pack and storage facilities provide potential sources of gas to make up short term outages. A longer term outage at a very large gas processing facility, main sales gas transportation pipeline or storage facility in close proximity to a demand point could have a significant impact on gas supply resulting in a restriction in flow or possibly a complete stoppage of flow for a period of time.

The highest probability that a single point outage would significantly impact a specific natural gas fired power generation facility is a failure or other outage on a dedicated single pipeline to the facility. The exposure to this type of failure or outage is dependent on many factors including the length of the pipeline, the terrain and the activity in the area of the pipeline. The impact of an outage further

¹¹⁸ http://www.transcanada.com/customerexpress/docs/ab_operations_planning_outage_forecast/OctoberPost.pdf

¹¹⁹ https://www.google.com/url?q=http://www.transcanada.com/customerexpress/docs/2016-09-22_ngtl-and-foothills-customer-meeting.pdf&sa=U&ved=0ahUKEwj9cWU7vbPAhWi7YMKHSY4CygQFggFMAA&client=internal-uds-cse&usg=AFQjCNE_VALcnzOknLBU_126G0RJNSLVEA

upstream from the dedicated pipeline depends on the design capacity of the system and the flexibility of the system to reroute gas around the outage.

High Level Natural Gas Fired Power Development Scenarios

High level scenarios to outline gas supply reliability considerations for routing gas to power generation sites are provided below. These scenarios are for illustrative purposes only; discussions with the pipeline operators are required to define system changes and expansions to supply selected delivery points.

Gas Generation Capacity to Replace Existing Coal Generation Plants

The first example examines adding 4,000 MW of natural gas fired power generation capacity located in the Wabamun area west of Edmonton to replace a portion of the current coal fired power generation. This area includes the coal fired Genesee, Keephills and Sundance power generating facilities. The Delivery Map for the NGTL system of October 5, 2016¹²⁰ indicates this area is currently fully contracted therefore there is very limited ability of the system to absorb incremental gas demand and respond to a failure by utilizing spare capacity in the system.

The area is shown on the following figure and is within the ATCO service area. The area north of Wabamun Lake is supplied by a single 10-inch pipeline with a capacity of 50 MMcf/d. The area south of the lake is supplied with a single 12-inch pipeline with a capacity of 80 MMcf/d supplied from 2 - 16 inch parallel pipelines that are connected to the NGTL system¹²¹ west of and off of the map area and the Edmonton area to the east. Capacity drops to about 20 MMcf/d through the 8-inch pipeline extension. At this time, there has been some prep work for the region to meet the future forecast demand.

An additional 30-inch-high pressure pipeline (or equivalent capacity from multiple smaller diameter pipelines) would be required to provide 680 MMcf/d of gas to generate 4,000 MW. The current 2 – 16 inch pipelines are likely operating near capacity and are too small to be of much use to supply the incremental demand, so clearly significant modifications to the system from the delivery point back to a secure source of gas on the NGTL Western Mainline, likely near Edson, would be required to meet total demand in the area. This would be a major realignment to the existing NGTL system. As this is a long distance for a single dedicated supply pipeline, redundancy should be considered to improve gas supply reliability in the area.

¹²⁰ [http://www.transcanada.com/customerexpress/docs/Delivery_Map_October_5_2016\(1\).pdf](http://www.transcanada.com/customerexpress/docs/Delivery_Map_October_5_2016(1).pdf)

¹²¹ The looped 16-inch pipeline from the supply tie in point to the Wabamun south area ties into a NGTL 30-inch pipeline that parallels the NGTL mainline 25 miles east of the mainline. There is currently an expansion project to loop a portion of this pipeline west of Drayton Valley to increase capacity. There are several receipt and delivery points along this pipeline system

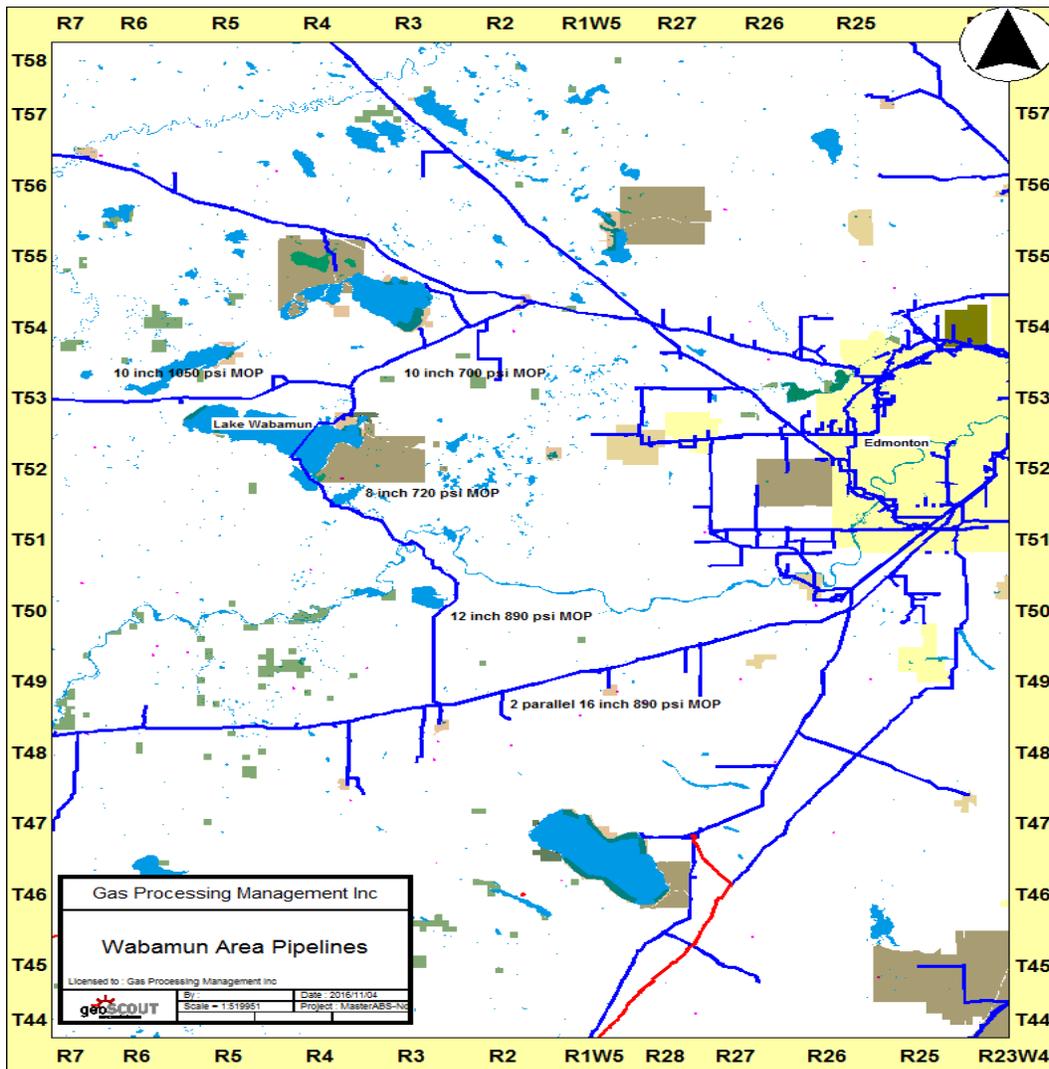


Figure 7.2 Wabamun Area Current Pipelines

Two more straight forward examples of supplying gas to existing coal fired power generating facilities are the Sheerness and Battle River power plants. These facilities currently produce 780 MW and 690 MW of power from coal and would require a 16-inch or 20-inch gas supply pipeline to each facility, however as the plants are located near the NGTL eastern AB mainlines¹²², a secure source of gas would be available with considerably less modification to the system.

Dedicated Supply Pipeline to a Current Gas Generation Site

This example describes the system delivering gas to the recently completed 860 MW combined cycle Shepard facility¹²³ located at the Calgary east city limit. Included in the project is a dedicated 20 inch 905 psi MOP gas pipeline from the ATCO system in the greater Calgary area.

¹²² 2 – 24 inch and 2- 30 inch pipelines

¹²³ Shepard AUC Application

The following figure shows the gas pipelines near the Shepard Power Generation Facility. A 20 inch, 10-mile-long, dedicated pipeline supplies gas to the Shepard facility. Additional pipelines in the area include a recently constructed 30/24-inch pipeline from the same tie in point as the Shepard supply pipeline, which extends south beyond the Shepard facility. These pipelines connect to the ATCO system that delivers gas to the east side of the greater Calgary area. The pipelines connect to 16 inch and 20 inch pipelines routed northeast to the ATCO Carbon Storage Facility (Wayne/Rosedale) and the large diameter NGTL mainlines from the James River junction to the AB/SK border. The combined ATCO and NGTL system feeding the tie in point location has considerable flexibility and sufficient capacity to minimize the impact of a single point outage upstream of the tie in point. The main risk to the gas supply to the plant is a failure of the dedicated 10-mile pipeline.

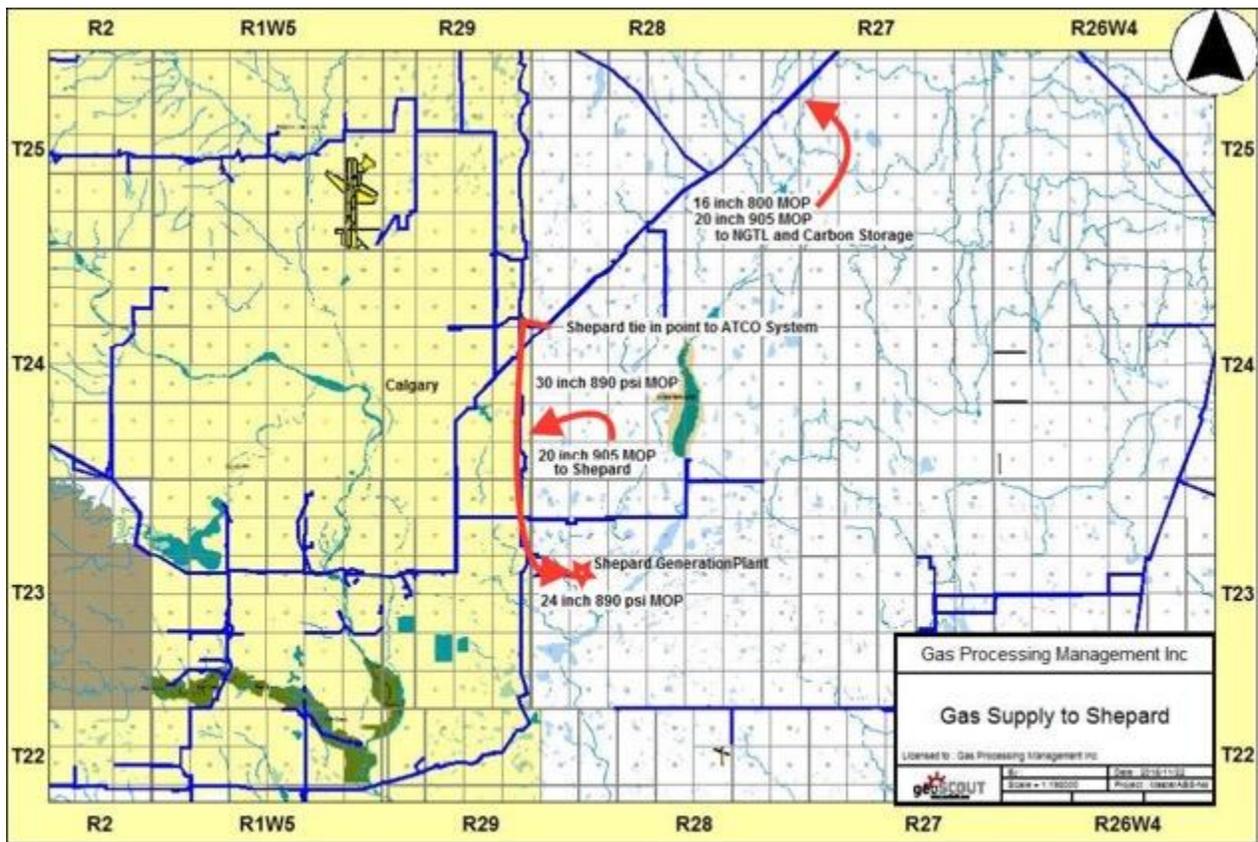


Figure 7.3 Gas Supply to the Shepard Power Generation Facility

Section 8: Intra Alberta Gas Commercial Arrangements

NGTL System Commercial Overview

The NGTL system is an interconnected system of 23,500 km of pipelines with over 1,100 receipt points and 380 delivery points. The system allows gas received by the pipeline (receipt point) to exit the pipeline (delivery point) anywhere on the system, provided there is sufficient physical capacity for both receipt and delivery. The system volumes are augmented with approximately 450 Bcf of gas storage in AB. Once gas is received by the system it can be traded between parties before it is delivered off the system.

The NGTL system is commercially integrated with ATCO pipelines¹²⁴. From the shipper's perspective, ATCO and the NGTL system are one pipeline system with an integrated tolls and tariff structure. NGTL manages the commercial, marketing (gas title trades) and billing operations and transfers revenue to ATCO. ATCO continues field operations of its system in coordination with NGTL.

NGTL Jurisdiction

Prior to 2009, the NGTL system was an AB intra-provincial system under provincial regulation. In April 2009, the NGTL system came under National Energy Board (NEB) jurisdiction with intentions to expand across the AB/BC border. The system currently receives gas in BC from two cross-border pipeline expansions: Saturn/Groundbirch (Montney) and Komie East (Horn River).

NGTL is regulated under the NEB Act as a common carrier. As a common carrier, NGTL is obligated to provide certain services to shippers in a non-discriminatory fashion¹²⁵. This requires tolls and conditions of services (tariff) to be transparent and equal for all shippers.

The NEB mandate is to regulate pipelines, energy development and trade in the interest of Canadians. The NEB oversees both physical and commercial aspects of NGTL including full-life pipeline operations (construction to abandonment) and approvals for expansions or extensions of the NGTL system. It should be noted that the ATCO portion of the system is regulated by the AUC.

NGTL Services

Under NGTL tariff, a series of service offerings have been established¹²⁶. The following five services are the most common:

- **Firm Transportation Receipt (FT-R)** - This provides for a firm service for a contract volume at a receipt point. During the primary term, the receipt is at a designation meter. During the secondary term, receipt can be transferred to another point on the system if there is available space.
- **Interruptible Receipt (IT-R)** - Interruptible receipt service is available at all receipt locations subject to available capacity. Interruptible service is at a lower priority and is the first service to be curtailed during capacity restrictions.

¹²⁴ See NGTL System Map (ATCO pipelines in green):

http://www.transcanada.com/customerexpress/docs/fh_system_maps/ab_system_map_2015_rev16.pdf

¹²⁵ NEB Act, Government of Canada: <http://laws-lois.justice.gc.ca/PDF/N-7.pdf>

¹²⁶ Detail NGTL System Services are available at: <http://www.transcanada.com/customerexpress/docs/Summary-of-NGTL-System-Services.pdf>

- **Firm Transportation Delivery (FT-D)** - This provides for firm service for a contracted energy quantity at a delivery point. During the secondary term, delivery points can be transferred to other points on the system.
- **Interruptible Delivery (IT-D)** - Interruptible delivery service is available at Group 1 or 2 locations subject to available capacity. Interruptible service is at a lower priority and is the first service to be curtailed during capacity restrictions.
- **Firm Transportation Point to Point (FT-P)** - This service is designated between a specific receipt and delivery point. The toll is based on distance between receipt and delivery point and may be at a discount to the sum of FT-R plus FT-D for the same two points.

Receipt and delivery based rates are dependent on location and the length of the contract term, as shown in the following table.

Table 8.1: NGTL Receipt and Delivery Contract Terms

Receipt or Delivery	Term	Percent of Base rate
FT-R	1-2 years	105%
FT-R	3-4 Years	100%
FT-R	5+ years	95%
FT-D	1-2 years	100%
FT-D	3-4 years	95%
FT-D	5+ years	90%

Shippers with FT-R contracts tend to be gas producers. FT-D contract holders include producers, banks, gas marketers, local distribution companies and other end users. FT-P service grew from shippers with both receipt and delivery needs in close proximity to each other. This service is available for any customer that is FT-P Group 2 on the NGTL system.

Tolling Methodology

Tolls are determined using a cost-of-service model. Under this model, NGTL is permitted to collect a fixed revenue (the revenue requirement). The revenue requirement is determined by factors including:

- **Return on Rate Base** - NGTL is allowed a deemed (not actual) capital structure of debt and equity (e.g. 60% and 40%) on the rate base (depreciated value of the pipeline assets). The return on equity is regulated (e.g. 10.1% on equity). This is an after tax return.
- **Depreciation and Amortization** - Each asset is depreciated at a specified rate. The depreciation and expense is part of the revenue requirement.
- **Flow-through Costs** - Flow-through costs are actual owning and operating costs and include: all taxes, operating expense and regulatory costs.
- **Transportation by Others (TBO)** - Tolls paid by NGTL to third party pipelines that are included as a NGTL transportation service to shippers are also added to the revenue requirement.

The cost of service is allocated amongst both delivery and receipt services using a methodology that recognizes transportation distances.

Table 8.2: NGTL Current Receipt Tolls¹²⁷

Service	\$/Mcf
Average rate	\$0.213
Floor Rate	\$0.133
Ceiling Rate	\$0.293

Delivery tolls are divided into three groups:

- **Group 1** (FT-D1) tolls are deliveries to downstream pipeline systems (e.g. Mainline, Spectra, Alliance, AB/BC Border (ABC)).
- **Group 2** (FT-D2) are all other non-Group 1 deliveries¹²⁸.
- **Group 3** (FT-D3) is at a premium to Group 2 service and is only available to shippers that are the downstream pipeline operator and the only shipper on the connecting pipeline. Group 3 tolls are also postage stamp but at a 20% premium to Group 2 tolls. Group 3 shippers have the highest priority and are the last shippers to be curtailed.

Delivery tolls are summarized in the following table.

Table 8.3: NGTL Delivery Tolls¹²⁹

Service	\$/GJ	\$/MMBtu
Empress/McNeill Border (Group1)	\$0.195	\$0.156
AB/BC Border (Group 1)	\$0.167	\$0.133
Gordondale/Spectra (Group 1)	\$0.167	\$0.133
ATCO: Clairmont/Shell Creek/Edson	\$0.167	\$0.133
Group 2	\$0.167	\$0.133
Group 3	\$0.200	\$0.160

In addition to the tolls paid above, fuel gas is taken in-kind from receipt point shippers. Fuel gas is approximately 1.5% of the total receipt gas volume. Additionally, shippers pay an abandonment charge of approximately \$0.01 per Mcf for all transportation services. NGTL provides a toll effective January 1st of each year (interim toll). This toll is commonly adjusted later in the year (final toll) as NGTL finalizes its COS, throughput and forecast assumptions. Tolls are calculated on an annual basis. Therefore, tolls are sensitive to changes in the annual depreciation, COS, contract demand quantity and throughput. The following chart shows the historic FT-R average toll.

¹²⁷ Rates based on a three firm receipt point contract. Source NGTL:
<http://www.transcanada.com/customerexpress/2766.html>

¹²⁸ See all delivery point and final rates for 2016 at:
http://www.transcanada.com/customerexpress/docs/2016_Final_Delivery_Point_Rates_and_Abandonment.pdf

¹²⁹ Rates based on a one-year delivery point contract. Source NGTL:
<http://www.transcanada.com/customerexpress/2766.html>

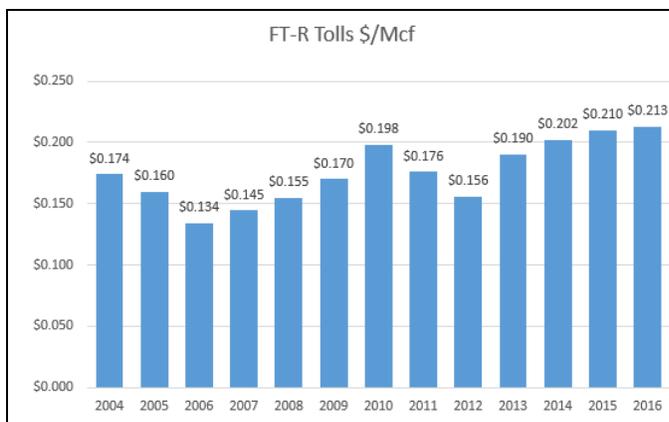


Figure 8.1: NGTL Average Annual FT-R Tolls¹³⁰

Requesting Service on the NGTL System

NGTL, as a common carrier, is obligated to accept reasonable request for service from shippers. If new facilities are required when contracting the service, then the service may require an additional term obligation. There are two types of contract term obligations defined in the Tariff: primary and secondary. During the primary term, the receipts/delivery points are fixed and cannot be substituted with other points on the system. During the secondary term the shipper can move service to other points on the system if capacity is available.

If FT-R service is requested and no new facilities are required, then the shipper is obligated to a minimum of a three-year secondary term. If there are no new facilities for delivery, there is a minimum one-year secondary contract required. If the request for FT-D requires a new meter, then the contract term is a two-year primary plus a minimum of three years secondary. For FT-D service requiring any other new facilities, it's a five-year primary term plus minimum three-year secondary term.

Although the NGTL Tariff sets minimum conditions, NGTL has the ability to negotiate for longer terms. For example, if significant pipeline capital is required, the contract term can be longer than 8 years.

A Project Expenditure Authorization (PEA) is required between NGTL and a shipper requesting service that requires new facilities. These agreements are used by NGTL for NEB filings (and becomes part of the public record) to show the shipper's obligations to the facility expansion. These agreements can include conditions precedent¹³¹ and potential off ramps for the project. If the project is terminated, then the shipper is obliged to pay cost to date plus AFUDC¹³². The PEA is executed along with the Service Agreement.

System Expansions and Extensions

NGTL is motivated to invest in system capital as it increases NGTL earning. However, new capital spending must be prudently incurred and approved by the NEB before proceeding. The approval process depends on the project size.

¹³⁰ Source NGTL archived rates: <http://www.transcanada.com/customerexpress/3698.html>

¹³¹ Conditions precedent are conditions that must either be met or waived before the project continues to the next phase. Examples include: Board approval, Final Investment Decision for LNG projects, project financing, etc.

¹³² Allowance for Funds Used During Construction – i.e. a return is earned on funds used during construction and the return is added to the capital rate base once the project is completed.

For smaller capital investments (e.g. pipelines under forty kilometers, compressor stations, storage facilities, etc.) NGTL will file a Section 58 Application. Many of these projects still require a two-season environment study plus stakeholder and First Nations engagement. A typical Section 58 Application will take nine months to one year to prepare. Based on the nature of the project, the NEB will decide if a public hearing is required. For non-hearing applications, the NEB provides guidance on the timeline for its approval process as follows:

Table 8.4: NEB Approval Guidelines¹³³

Category	Complexity of Issues	Service Standard Target	Maximum Time Limit
A	Minor	80 per cent of decisions released within 40 calendar days*	130 days
B	Moderate	80 per cent of decisions released within 90 calendar days*	210 days
C	Major	80 per cent of decisions released within 120 calendar days*	300 days

* The NEB remains committed to processing applications in accordance with its Service Standards. These standards do not include timeouts (previously, any period of time during which the NEB had limited or no control over the processing of an application was considered a timeout). The NEB will implement a two week timeout during the holidays in December. Note that any modification to the time limit which is permitted by statute will apply to both the service standards and time limits. Any such modifications will be shared publically.

For larger projects, a Section 52 Application is required with a public hearing – either oral or written. A Section 52 application requires a four season environmental study and significant pre-application work. This can take 18 months up to two years to complete.

Once the application is completed it is submitted to the NEB for a completeness review. It takes approximately three months for the NEB to review the application before it is accepted. Once the application is considered complete, the NEB has 15 months according to the legislation to finish the application process and provide its final report and recommendation to Government in Council (GIC). During this period, there will be a series of information requests and responses required by the proponent, NEB and interested parties. There will also be either a written or oral hearing. Once the final report is issued, the GIC has three months to accept, modify or reject recommendation. All of these timelines can be extended at the discretion of the NEB or GIC.

The application process for major pipelines can be very expensive (tens to hundreds of millions of dollars). NGTL uses the PEA as a backstopping agreement with security provisions. In other words, NGTL funds the work but if the project is terminated (e.g. does not receive regulatory approval), then the parties to the PEA pay NGTL’s incurred costs.

NIT and the Gas Market

The NGTL system should not be thought of as a point-to-point pipeline. Instead, it is a series of receipt points (gas flowing onto the system) and a series of delivery points (gas flowing off the system). Between receipt points and delivery points is a market where gas title is transferred between shippers. The title transactions are facilitated through Nova Inventory Transfer system (NIT).

NIT is North America’s largest physical gas market. Once gas is received at a receipt point it enters the NIT account of a shipper. The shipper can either sell the gas to another shipper or deliver the gas to a delivery point or storage. Volumes of gas, once received by the system can be transacted (sold and bought) many times before it is delivered. Typically, gas transfers ownership 5 to 6 times per day before

¹³³ Source NEB: <https://www.neb-one.gc.ca/bts/whwr/gvrnnc/nbsrvctndrd/index-eng.html>

it is delivered off the system. Shippers on NIT must balance their accounts daily, within accepted tolerance based on system conditions, such that receipts and purchases equals deliveries and sales.

The title transfers on NIT are independent of physical flows. For example, gas received in the northwest AB can be transferred to a shipper with delivery anywhere on the system. There is no extra charge for long distances between receipt and delivery points. In addition, there is no current charge for title transfers on NIT. Therefore, at a given time, there should be no difference in prices for gas deliveries anywhere on the system.

Types of Transactions

Gas can be bought or sold (title transfer) at NIT in three ways:

- The buyers and sellers can be in direct contact and enter into a sales agreement. These agreements will include conditions on pricing and contract terms. This is considered an Over-the-Counter (OTC) contract as it does not exchange on the open market. In this OTC, the party and counterparty are known and security is arranged between the parties.
- Gas sales agreements can be made through a third-party marketing company (e.g. Goldman Sachs, BP). In this case, the marketing company manages both the buy and sell agreements. This is also an OTC contract, however, the marketer would manage security and, as a gas aggregator, a portfolio of sale and buy contracts.
- Trades can occur through Natural Gas Exchange Inc.¹³⁴ (NGX) electronic trading platform¹³⁵. In this case, the counterparties are unknown and security is managed by NGX with security requirements established according to regulations between NGX and its clients. The buy and sell transactions are transparent and set the published index prices.

NIT gas-trading market provides a well-established market system with transparency, liquidity, flexibility and access to a large production base. NIT market trades against common North American hubs and NGTL volumes can be exchanged through hub swaps. In addition, the Natural Gas Exchange Inc. (NGX) provides an electronic trading platform and counterparty clearing for NIT. NGX has an operational alliance with Intercontinental Exchange (ICE) and uses ICE's trading technology to provide integrated trading services for gas across North American markets. NGX is located in Calgary and is 100% owned by the TMX Group.

Spot Market

The spot price is for gas that is physically in the pipeline and traded during the day. The price is determined by need to fill both receipt and delivery nominations and obligations. If there is greater demand (delivery) than supply (receipt) market prices will increase. Conversely price drop when supply outstrips demand. Spot prices are determined by daily physical trades on NGX.

Both line-pack and storage are used to balance supply and demand and therefore moderate prices. The system line pack (gas stored within the pipeline system) is approximately 16 BCF and must be maintained within specific tolerances (normally +/- 4%). However, shippers are allowed a slight

¹³⁴ NGX is located in Calgary and is 100% owned by the TMX Group

¹³⁵ NGX has an operational alliance with Intercontinental Exchange (ICE) and uses ICE's trading technology to provide integrated trading services for gas across North American markets

imbalance in the NIT account where they can add to or subtract from the line pack over the short term. Shippers can adjust their imbalances in response to market prices. Additionally, storage is driven by NIT prices resulting in swinging withdrawal or inject volumes, depending on operational conditions, by up to approximately 2 Bcf/d day over day.

On occasion, spot prices can spike over the short-term. The following figure shows the AB spot price from July 2012 to October 2016. A spike in gas price occurred in the winter of 2013/14 with the spot price peaking at almost \$25.00 per GJ on February 5, 2014. Primary drivers to the price spike include the onset of the Polar Vortex across North America and price strength in the US Northeast. The price remained high in February with a few additional price spikes.

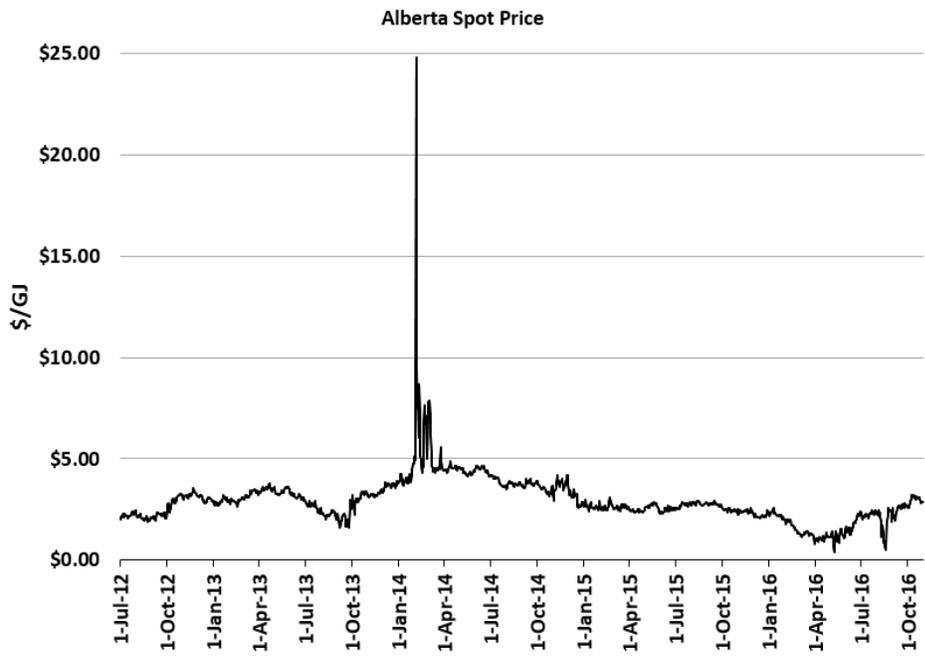


Figure 8.2: Alberta Spot Price 2012 to 2016¹³⁶

The following figures show the supply and demand factors affect the price in February 2014. Figure 8.3 shows the demand curves on the NGTL system, intra-AB, exports and total demand. Leading up to the price spike, total demand increased from 12 Bcf/d to over 14 Bcf/d (The NGTL system was near its capacity at 14.0 Bcf/d). Figure 8.4 shows the AB supply on the NGTL system: field receipts (producer gas), storage receipts and total supply. Field receipts were approximately 10 Bcf/d prior to the price spike but dropped off to approximately 9.5 Bcf/d as prices increased. Withdrawals from storage (and line pack) were used to make up the gap in supply. However, storage inventories were lower in early February decreasing the capacity to withdraw gas at higher rates. The 4 Bcf/d of storage withdrawal was likely near the maximum capacity of the storage facilities. All of these factors combined together to increase prices.

¹³⁶ Source: NGX

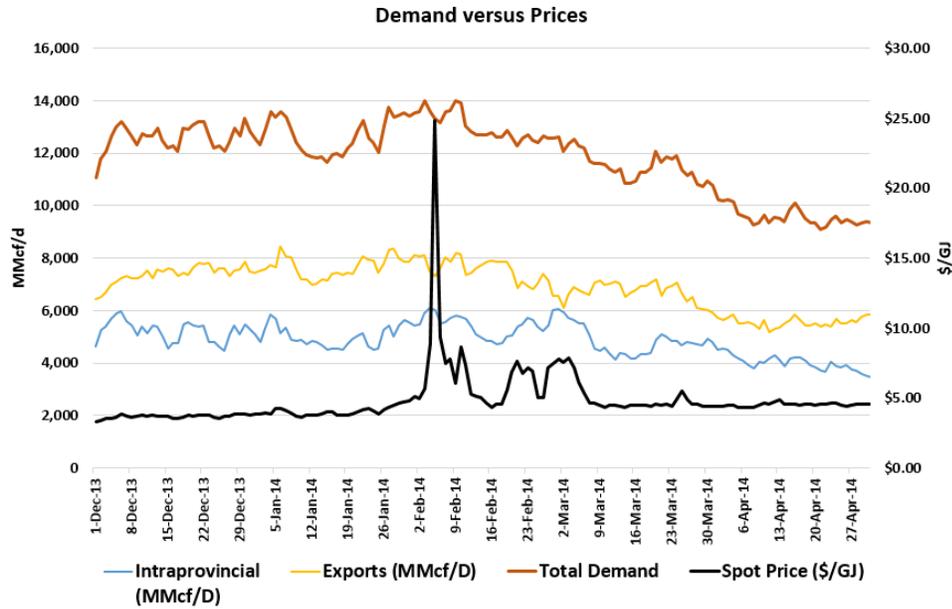


Figure 8.3: Western Canada Demand and Price 2013 to 2014¹³⁷

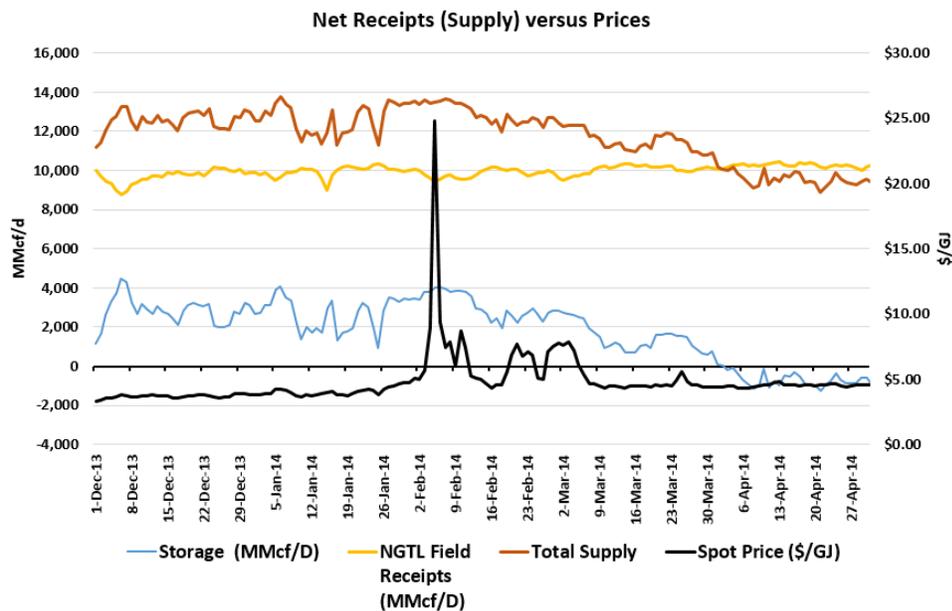


Figure 8.4: Western Canada Net Receipts and Price 2013 and 2014¹³⁸

Figure 8.4 also shows how the market compensated for higher AB prices. Exports decreased as sellers of gas had higher profits in the AB market. Additionally, storage withdrawals increased as storage holders took advantage of the increased prices. Field receipts are not as responsive in the short term to price changes. However, field receipts did increase marginally through February.

¹³⁷ Sources: NGX and NGTL

¹³⁸ Sources: NGX and NGTL

Natural Gas Futures

To avoid spot market price anomalies, natural gas can be bought and sold for delivery in the future. For example, on the NGX, the “AB-NIT month ahead index 7A” index is a liquid trading product for next month’s natural gas deliveries. Using this index, gas could have been bought in January 2014 for delivery in February 2014 at average price for \$4.23 /GJ versus the spot market average price of \$8.04 /GJ¹³⁹. The month ahead index can be used to avoid short-term (daily) price spikes.

Natural gas futures can also be bought on the on NYMEX exchanges against Henry Hub pricing (“paper” gas) or negotiated with OTC contracts. These contracts can be negotiated with various pricing options and can be used to mitigate spot price spikes. These contracts are typically negotiated with gas marketers or banks but can include direct contracting with gas producers.

Commercial Requirements

A natural gas fired electric power operator will require two sets of ongoing commercial agreements/arrangements:

- **Transportation** - For gas deliveries on the system, the shipper will require a delivery point service agreement. To ensure capacity is available when needed, the shipper would enter into a firm demand contract (FT-D). This contract requires the shipper to pay a fixed monthly demand charge based on a daily delivery volume. For security of supply, the shipper could contract based on peak demand requirements and pay unutilized demand charges (UDCs) on days when flows are below peak requirements. If the shipper is concerned about FT-D curtailments, then the shipper could contract over peak demand such that there was a buffer to manage FT-D curtailments.

If the shipper is the single shipper and owner of the downstream pipeline (a likely scenario for a power producer), then the delivery point could be designated as a Group 3 delivery. The shipper pays a 20% premium for the delivery service; however, this high priority service is the last service to be curtailed.

Alternatively, if the delivery point is unlikely to be curtailed and interruptible service was reliable, then the shipper could contract FT-D below peak demand and rely on IT-D to manage peak demand load. With FT-D, firm service not used on the day can be credited against IT-D used during a month. This “Alternative Access” feature of FT-D can be transferred between and/or within any Group 1 or Group 2 delivery point.

- **Gas Procurement (Marketing)** - Power producers are significant buyers of natural gas. Typically, large buyers of gas will develop a portfolio of supply. This portfolio could include OTC gas contracts with various expiry terms and pricing conditions along with spot purchases. OTC contracts can be negotiated with multiple types of sellers including: gas marketers, banks and producers.

The GasEDI standard contract is a master agreement for gas trading in AB. However, this contract is commonly amended and augmented. Common terms of negotiation include:

¹³⁹ The trade volume weighted average index price for trades in January for 7A and in February for 2A. Source NGX: http://www.ngx.com/?page_id=644

- Pricing - Based on an index price (e.g. AB-NIT month ahead index 7A, spot price, etc.) or can include a future or fixed price. A price premium is paid for flexible contract terms – e.g. variable daily volume of gas.
- Duration or Term - Contracts can be short term (six months or less) or long-term multi-year contracts.
- Quantity - Volumes can be variable with a base load and minimum/maximum requirement. Flexibility comes with a premium price.
- Non-Performance - If the seller fails to deliver, then the buyer will need to procure gas through other means. Contract term will include the settlement of damages associated with failure to deliver.
- Force Majeure - Acceptable force majeure failures are negotiated between parties and how damages are relieved in the case of a force majeure event.
- Credit and Security - Contracts will have credit and security requirements. These can vary based on the creditworthiness of each party.

Summary

Since the deregulation of natural gas in 1985¹⁴⁰, a well-established market has developed AB. With many buyers and sellers and significant gas volumes, the market has become flexible in accommodating the needs of the market participants. As the power mix changes in AB, the market will need to continue to evolve and provide new services and products to manage the changing energy mix.

¹⁴⁰ NEB <https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/prcstrdrctcl/qtrlrprcpdts/ftrrtcl/11-01nnvrsrdrgltn-eng.html>

Section 9: Storage

Storage Terminology

When considering both physical and commercial aspects of gas storage, several key terms are used:

- **Working Gas** - The amounts of gas that can be injected and withdrawn from the storage facility. It is the total amount of gas that can be stored and made available to the market at a later date.
- **Cushion Gas (Base Storage)** - Gas that is added to the storage facility to provide pressure support to move working gas in and out of the stored facility. Depending on the type of storage facility, cushion gas can range from 20% to 80% of the total gas in the storage facility. Under normal market conditions, the cushion gas will remain in the storage facility throughout the life of the facility. Cushion gas is injected into the storage facility in preparation for commissioning. Ideally, this gas is injected when prices are low as the gas will remain in the reservoir and not be cycled. The storage owner can either buy cushion gas on the market or enter into a leasing agreement with a supplier. Regardless, the storage customer does not pay directly for the cushion gas. However, the toll indirectly includes a cost associated with cushion gas.
- **Total Capacity** - The amount of working gas in storage when the facility is filled to its maximum capacity.
- **Cycle Speed** - A measure of a facility's capacity to move gas in and out of storage. The facility's cycle speed is a hypothetical calculation of the number of times a facility could be filled to total capacity and emptied to the cushion gas volume over a one-year period. For example, a cycle speed of three is a facility that can theoretically be filled and emptied three times within a one-year period. Storage facilities with large cycle speed can provide greater contractual flexibility. Cycle speed can also be used in reference to contract terms (commercial agreement). For example, if a producer had a contractual right to 0.5 Bcf of storage with an injection/withdrawal rate of 5.5 MMcf/d, then the storage could be filled and emptied 182 days (1/2 year) or at a cycle speed of two. The contract cycle speed is independent of the facility cycle speed. In storage contracts, the higher the cycle speed the costlier the storage right costs.
- **Injection Rate/Withdrawal Rates** -: The rates are unique for each facility and depend on the supporting infrastructure (e.g. compressors, number of wells, etc.) and the amount of working gas in the reservoir. When the storage facility is empty (except for the cushion gas) the pressure is lower and injection rates are higher. As the storage facility fills, the pressure increases and the rate of injection decreases. Conversely, when the pressures are high and the facility is full, higher withdrawal rates are possible. As the storage is drawn down the pressure decreases and withdrawal rates decrease. Gas storage facilities are designed with faster withdrawal rates versus injection rates as the withdrawal period is typically shorter than the injection period (approximately 5 months versus 7 months).

Types of Storage Facilities

In North America, there are primarily three types of underground gas storage facilities: depleted reservoirs; salt cavern storage; and aquifer storage.

- Depleted reservoirs tend to have the lowest cycle speed (0.9 to 1.2) and require significant cushion gas (approximately 50%). Despite these drawbacks, depleted reservoirs are abundant

throughout North America and most gas storage in the Western Canada Sedimentary Basin (WCSB) are in depleted reservoirs.

- Salt cavern storage tends to have the highest cycle speed (4 to 5) and requires the least amount of cushion gas (25-35%). These high cycle speed facilities are capable of operating on a daily basis, storing gas during the evening and withdrawing during the day to meet peak demand. As these facilities are only in areas with large salt deposits, most salt storage facilities are located in the US Gulf Coast area, with a few located in the Michigan Basin (Michigan and southern Ontario).
- Aquifer storage is developed in water aquifers and have cycle speeds between depleted reservoirs and salt caverns. However, aquifer storage requires significant cushion gas (80%) and are expensive to develop. Aquifer storage is developed near end markets where depleted reservoirs or salt caverns are not available.

In addition to underground storage, natural gas can be stored either as compressed gas or as liquefied natural gas (LNG). LNG storage in tanks can be used to augmentation supply (peak shaving) during times of high demand. For example, Fortis BC operates the Mt Hayes LNG storage facility on Vancouver Island that provides 1.5 Bcf of liquefied natural gas storage. This facility is used in the winter during period of high demand to mitigate supply concerns due to limited pipeline capacity from the mainland to the Island.

Physical Storage

There are ten storage facilities shown on the following figure (from the AER}. However, two of the ten facility are not active storage facilities. The Brazeau River facility has not been fully implemented and lacks full injection withdrawal facilities. It operates not in the typical fashion of summer injection and winter withdrawal. Instead, it is used for NGL extraction processes.¹⁴¹ The Dimsdale facility application was approved by AER in April 2015. However, at this time, the facility does not appear to be operational. Attempts were made to contact Ranchwest Energy but their phone is no longer in service.

¹⁴¹ Brazeau Fiver (Rat Creek) information based on an email from Marty Laznicka at TransCanada, January 8, 2016.

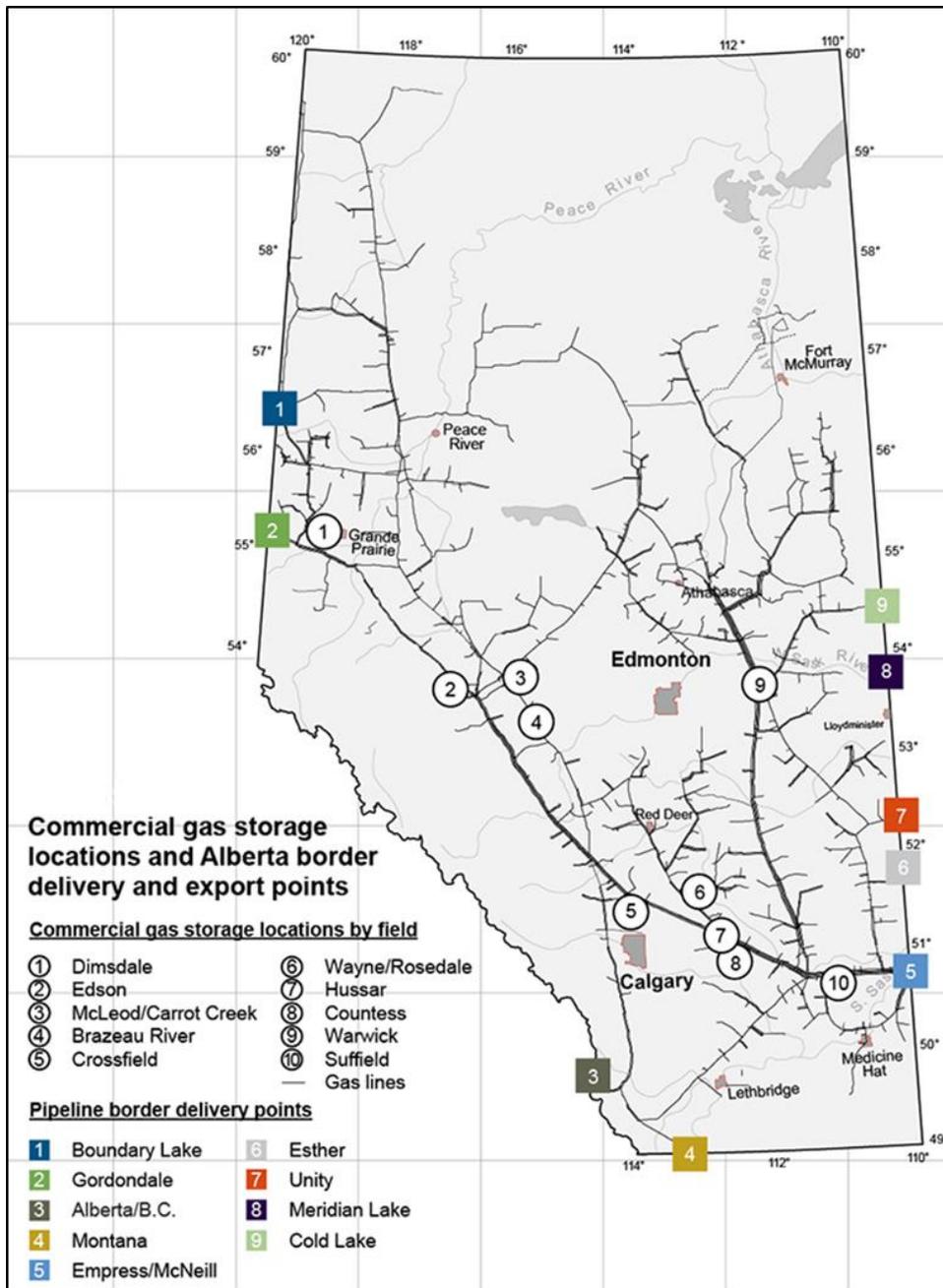


Figure 9.1: Gas Storage Schemes in AB¹⁴²

In AB, the remaining eight facilities have an estimated working gas capacity of approximately 322 Bcf according to AER as shown in the following table. However, AER storage capacity numbers are considered conservative and other industry estimates put AB storage capacity at approximately 450 Bcf¹⁴³. The peak receipt meter capacity is approximately 6 Bcf/d. Most of the storage facilities have been developed close to the NGTL system export points allowing for higher withdrawal capacity during

¹⁴² Source AER: <https://www.aer.ca/data-and-publications/statistical-reports/natural-gas-storage>

¹⁴³ Based on other public and confidential sources

winter peak seasons. Currently, as less gas is exported out of AB, the Warwick facility (#9) was developed close to oil sand operations to support the growing market needs in this area.

Table 9.1: Western Canada Gas Storage Schemes¹⁴⁴

Facility	Ownership	Receipt Meter Capacity MMcf/d	AER Working Gas Estimates Bcf
1. Dimsdale	Ranchwest Energy(?)	unknown	84 (not operational)
2. Edson	TCPL	1,250	64
3. McLeod/Carrot Creek	Enstor	500	45
4. Brazeau River	Blaze	100	33 (not operational)
5. Crossfield East	TCPL	500	42
6. Wayne-Rosedale	Atco	490	40
7. Hussar	Husky	200	14
8. Countess	Niska – Carlyle Riverstone	1,240	55
9. Warwick	Perpetual (Paramount)	220	31
10. Suffield	Niska – Carlyle Riverstone	1,790	31
Total AB ¹⁴⁵		6,190	322
Aitken Creek	Fortis	500	77 (BC)

Aitken Creek storage facility (not shown in Figure 9.1) is located in BC near the T-North Spectra pipeline and the inlet to the Alliance pipeline. The Aitken Creek storage facility has a storage capacity of 77 Bcf and was recently sold by Chevron to Fortis for US \$266 million¹⁴⁶. This facility is not directly connected to the NGTL system. However, if the North Montney expansion is built, it will provide direct access to the NGTL system.

The following figure shows net storage deliveries¹⁴⁷ from December 01, 2008 to October 24, 2016. The graph clearly shows the seasonal balancing provided on NGTL by the AB storage facilities. The peak injection and withdrawal over this period was approximately 2 Bcf/d and 4 Bcf/d respectively.

¹⁴⁴ Adapted from: AER: <https://www.aer.ca/data-and-publications/statistical-reports/natural-gas-storage> and NGTL Annual plan: http://www.transcanada.com/customerexpress/docs/ab_regulatory_filings/2015_Annual_Plan_December_15_2015_final.pdf

¹⁴⁵ Total net Dimsdale and Brazeau River

¹⁴⁶ Fortis Expands its Gas Infrastructure Assets in BC: <https://www.fortisinc.com/News/Pages/Fortis-Expands-its-Gas-Infrastructure-Assets-in-British-Columbia.aspx>, December 3, 2015

¹⁴⁷ Positive net storage values are deliveries into storage and negative values are receipts onto NGTL out of storage.

NGTL Daily Net Storage (Deliveries)

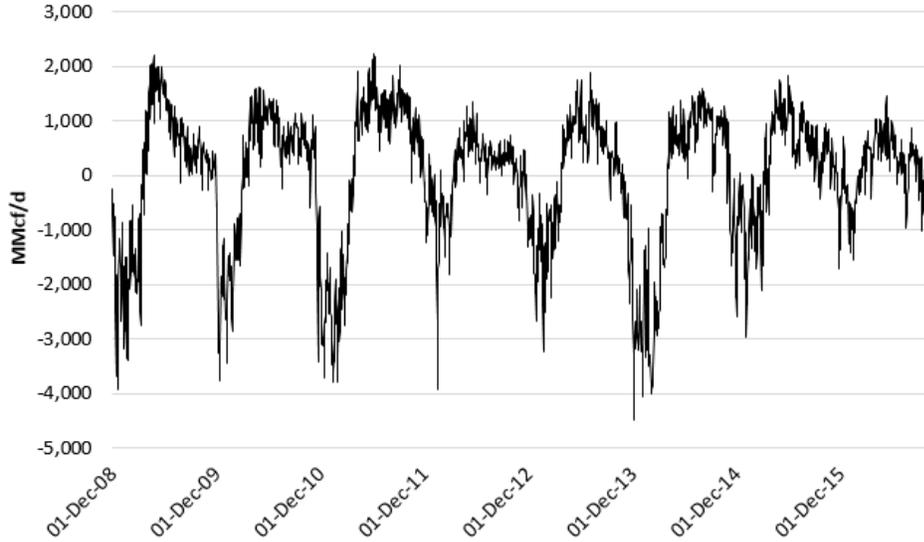


Figure 9.2: NGTL Daily Net Storage Deliveries 2008 to 2015¹⁴⁸

In January 2014, there were large price fluctuations on the spot market resulting in large daily changes in net withdrawals from storage. For example, on January 17, 2014 net storage withdrawals decreased by 2.0 Bcf in a single day. On January 26, 2014 net storage withdrawals increase 1.9 Bcf in a single day. Bases on these actual responses from storage, the system is capable of adding or decreasing approximately 2 Bcf/d during the peak winter season (as shown on the following figure). However, this response will depend on working gas levels and withdrawal rates will decrease as levels fall.

Daily Supply Changes From Storage

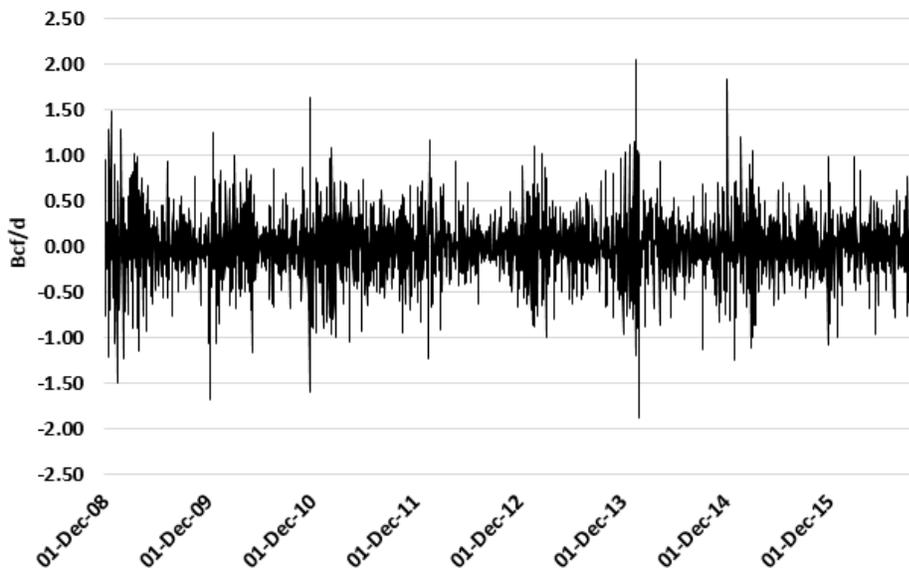


Figure 9.3: Daily Supply Changes from Storage 2008 to 2015¹⁴⁹

¹⁴⁸ Source: NGTL Gas Day Summary Report

Commercial Storage

Gas storage is used in North America as part of the integrated gas market. As more natural gas is consumed in the winter than in the summer, gas is stored during the summer when demand is lower and released in the winter when demand is higher. Gas supply therefore remains constant even as gas demand fluctuates.

The following figure shows the seasonal changes of gas demand and storage levels for the US. The peak season for gas demand is December through March. During this period, gas is withdrawn from gas storage and inventory levels drop. From April through to November, gas is injected into storage and inventory levels increase.

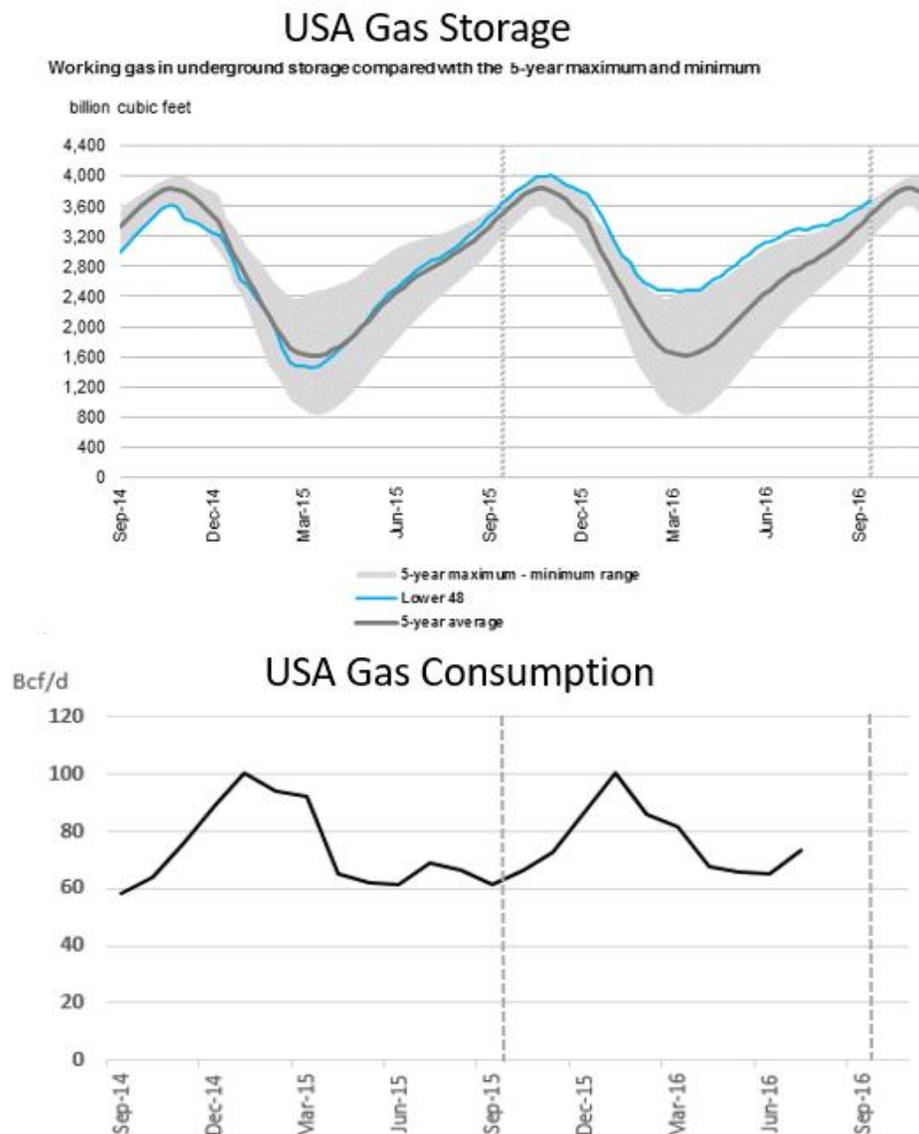


Figure 9.4: US Natural Gas Storage and Consumption 2014 and 2015¹⁵⁰

¹⁴⁹ Source: NGTL Gas Day Summary Report

¹⁵⁰ Source: EIA, October 2016

The winter demand sets the minimum inventory level. For example, the winter of 2015/2016 was late and warm and the demand for gas was lower than normal. As a result, the withdrawal rate was lower and the inventories have remained at the five-year maximum range.

Although gas storage provides balance in the supply and demand cycles, it is used with the anticipation that natural gas prices will be higher in the winter than in the summer. As there is a cost associated with gas storage, the gas owner interested in making a profit must sell the gas at a higher price in the future. In the simplest model, gas would be injected in the summer when prices are low and withdrawn in the winter when prices are high. The difference between the two prices must be equal to or greater than the total cost of storage. However, this simple model is risky and depends on the variations of the seasonal demand.

For example, the following figure shows the AB monthly price¹⁵¹ from January 2012 to December 2015. The areas shaded in red and green represent storage withdrawal and injection periods respectively. The 2012 curve shows a seasonal cycle where the price in January and February was above \$2.00 /GJ and fell to a low in May of \$1.50 /GJ, remained below \$2.00 until August, and increased to \$3.00 /GJ in November and December. However, in 2013, the highest prices were in May and June during the injection season. Additionally, the 2015 prices were higher in August to October (injection) versus November and December (withdrawal). Therefore, seasonal pricing is not predictable and depends on multiple market factors.

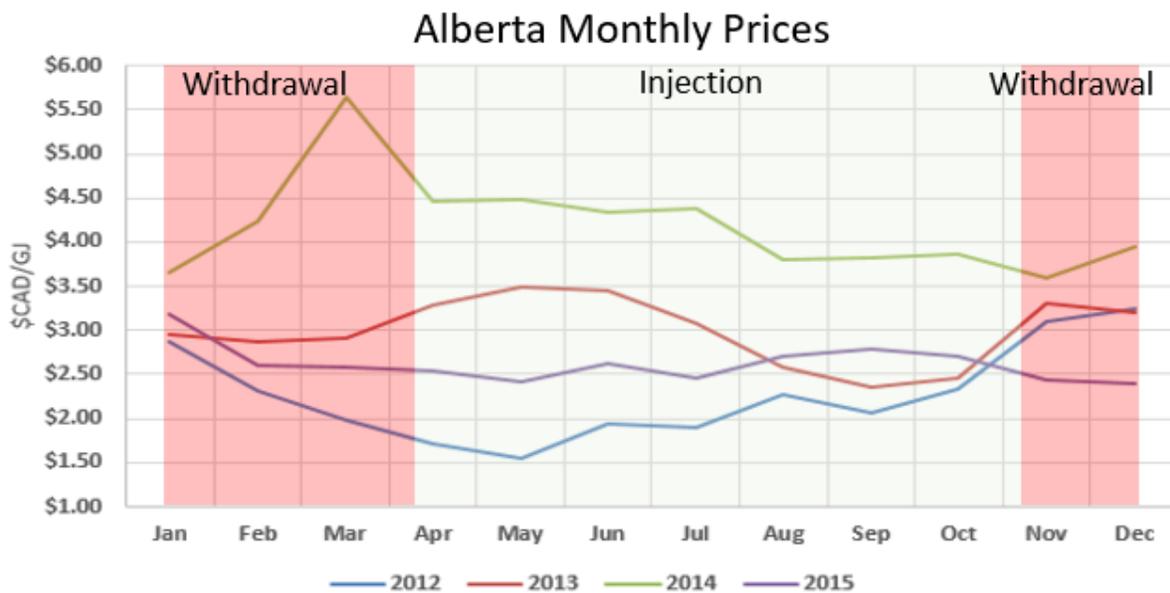


Figure 9.5: AB Monthly Natural Gas Prices 2012 to 2015¹⁵²

To avoid the uncertainty associated with future prices, gas storage holders will use hedging strategies. For example, the following figure¹⁵³ shows a series of forward curves for AECO pricing. The price curves

¹⁵¹ Source NGX: month ahead index 7A

¹⁵² AB Prices from NGX

¹⁵³ Forward curves in December 2015 from: <http://www.gasalberta.com/gas-market/market-prices?p=pricing-market.htm>

show a clear seasonal pattern from storage injection (green shaded area) to storage withdrawal (red shaded area). For example, gas can be purchased in the summer of 2017 for \$2.80 /GJ and can be sold in the winter 2017/2018 for \$3.20+ /GJ. This provides a gross margin for a storage holder of \$0.50 /GJ.

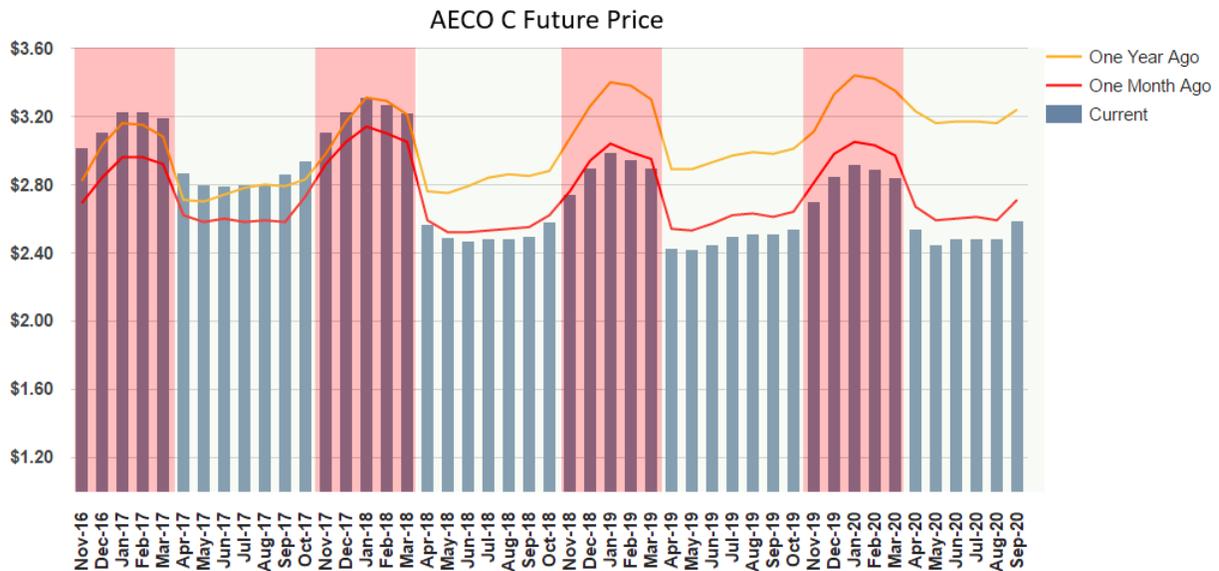


Figure 9.6: AB-NIT Future Prices 2017 to 2020¹⁵⁴

As also shown in Figure 9.6, the forward curve continually changes over time. For example, future prices one year ago (yellow curve) are higher than the current future prices for gas futures starting in April 2018. The future price in April 2018 one year ago was approximately \$2.80 /GJ. The future price of April 2018 is now approximately \$2.55 /GJ. Therefore, a gas marketer could have made \$0.25 /GJ gross margin by buying a future in 2015 and selling it 2016.

Both local distribution companies (LDC's) and banks/marketers hold gas storage contracts. The LDC's provide gas to residential, commercial and industrial customers. Companies in Canada include ATCO, Fortis, Union Gas and Gaz Metro. The LDC's maintain gas storage for both security of supply and to manage gas prices. However, although there is some competition among LDC's and other marketers in Canada, significant price changes can be passed onto the customer. Secondly, banks and marketers also hold storage as part of the hedging services provided to both buyer and sellers. These companies use hedging portfolios with gas storage to ensure they can profit from providing hedging services to buyers and sellers.¹⁵⁵

Storage Receipt and Deliveries

On the NGTL system, shippers do not pay either receipt or delivery tolls to move gas off the system and into storage. This service is free of charge on NGTL (and T-North for Aitken Creek). In addition, gas moved into storage comes off the shippers' NIT account for daily balancing¹⁵⁶; gas is added back to the

¹⁵⁴ Adapted from <http://www.gasalberta.com/gas-market/market-prices?p=pricing-market.htm> October 2016.

¹⁵⁵ As gas storage is not a merchant market detailed customer information is not available. The statements concerning the types of customers are based on conversations with TransCanada in December 2015.

¹⁵⁶ Gas received on to the NGTL system goes into a NIT account and must be cleared daily by either gas delivery off the system, sale to another account holder and moved to storage.

NIT account when it is withdrawn from storage. The daily NIT accounts must be balanced within NGTL's tolerance regardless if gas is injected into storage (off the NIT account) or withdrawn from storage (added back to NIT account). As storage facilities are independent of NGTL, no additional NGTL balancing rules are applicable to the gas once it is off the system and injected into storage. It is also important to note that storage injections and withdrawals are not firm onto the system.

Gas Storage Contracts

Storage facilities in Canada are operated as merchant enterprises which allows owners to negotiate storage contracts based on market conditions. This is unlike the US where storage facilities are regulated by the Federal Energy Regulatory Commission (FERC) and are based on open access and a cost-of-service/rate-of-return toll model (i.e. similar to regulated model of NGTL tolling). Therefore, parties interested in storage services must negotiate directly with the storage providers in Canada.

Gas storage contracts fall into two main types:

- **Park/Loans** - Park/Loans have rigid contractual conditions. In this case the storage customer agrees to a fixed storage capacity for a fixed term. The injection and withdrawal rates and schedule are also fixed. The customer pays a unit fee on injection (e.g. \$0.20 /GJ) and the same fee on withdrawal (e.g. \$0.40 /GJ total charge). The service is 100% firm meaning the customer pays the demand charge regardless if it uses the service or not.

Park/Loan contracts can be used for the long-term seasonal cycles or shorter monthly contracts. For example, an LDC will inject during the summer when demand is lower and withdraw during the winter when demand is higher. By doing this, the LDC has assurances of supply at a predetermined price, regardless of the winter market pricing conditions. Similarly, a marketer may need to balance an account between a seller and buyer over a shorter term (e.g. monthly) and can use a Park/Loan contract over a shorter period.

- **Term Storage** - Term storage provides a flexible agreement where the customer reserves a maximum capacity but chooses when to inject and withdraw. Term storage has a fixed term (i.e. a start and end date to the storage option) within a window whereby the customer can manage the injection and withdrawal periods.

As the physical ability to inject and withdraw are dependent on the volume of gas in storage, the term storage contract has a "curve" or "ratchet" associated with injection and withdrawal rates. As the volume in storage increases, the ratchet rate for injection decreases. This means the customer cannot inject at a rate higher than the ratchet rate. Conversely, as the storage volume decreases, the ratchet rate for withdrawal also decreases. The following table shows an example of a rate schedule based on a reserve capacity of 1,000,000 GJ. The Inventory Range is measured as a percent of the working gas capacity.

Table 9.2: Western Canada Natural Gas Storage Injection and Withdrawal Inventories¹⁵⁷

Injection		Withdrawal	
Inventory Range	Max Daily Injection	Inventory Range	Max Daily Withdrawal
0%-35%	11,930 GJ/d	0%-14%	5,000 GJ/d
35%-60%	8,670 GJ/d	14%-28%	7,400 GJ/d
60%-78%	6,200 GJ/d	28%-48%	9,800 GJ/d
78%-91%	4,500 GJ/d	48%-69%	13,200 GJ/d
91%-100%	3,250 GJ/d	69%-100%	16,900 GJ/d

For this reserve capacity, the customers pay a monthly fee over the term of the contract. For example, if the term was one year, reserved capacity was 1,000,000 GJ, and demand fee was \$0.36 /GJ, then storage cost would be \$360,000. The client would therefore pay \$30,000 per month. In addition, the customer would pay a commodity fee on injection and withdrawal (e.g. \$0.02 /GJ each way or \$0.04 /GJ total) plus a fuel charge (approximately 0.75% of the storage cost or \$0.0027 /GJ on both injection and withdrawal). Therefore, in this example, if the total volume of reserved capacity was used, the cost would be \$360,000 (storage right) plus \$40,000 (commodity fee) plus \$5,400 (fuel costs) or a total of \$405,400.

The example above is based on a one-year term storage contract. If the term was longer, the value of the storage option increases. For example, in the case of a two-year contract, the storage owner must now reserve the right to storage over a longer period and has less ability to market this storage amount. As a result, the customer pays a higher monthly demand fee.

Often spot market prices can change abruptly with large spikes. The following figure shows the daily Henry Hub pricing over a 9 ½ year period. As the graph shows, there have been six large short-term spikes in gas prices over this period. Holders with gas in storage under term contracts will withdraw as much gas as possible during these pricing spikes to take advantage of the high prices.

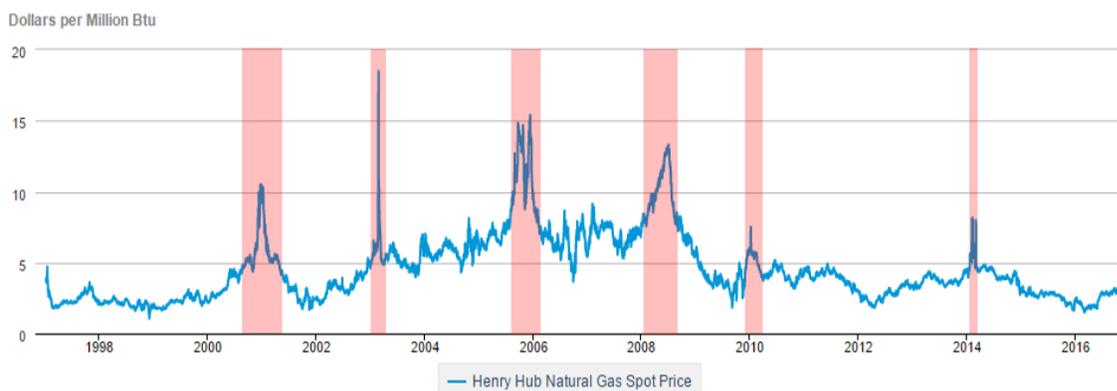


Figure 9.7: Henry Hub Spot Natural Gas Prices 1988 to 2016¹⁵⁸

¹⁵⁷ Rate schedule example as provided by TransCanada example PowerPoint, *Gas Storage*, Marty Laznicka, December 2015.

Both the Park/Loan and Term storage examples provided are for illustrative purposes. Actual contract terms can be a hybrid of both types of contracts and depend on the particular needs of the customer and the market conditions. For example, contract terms can range from one month to 20 years with options on additional rights, including rights to extend terms, increase volumes or interruptible services. Customers can also pay premiums for higher cycle speed in order to take advantage of short term fluctuations. In addition, the value of storage changes with the forward price curve. For example, if the spread between summer and winter prices increase, then the value of storage increases. Both the buyer and the seller will price storage based on the forward curve. Since storage tolls in Canada are not regulated, these and other conditions are unique to each contract and are negotiated between the storage owner and the storage customer.

¹⁵⁸ Adapted from USA Energy Information, <https://www.eia.gov/dnav/ng/hist/rngwhhdd.htm>, *Henry Hub Historical Prices*, October 2016.

Section 10 – Alberta Natural Gas Fired Power Generation Overview

The following section summarizes the integration of natural gas fired power generation into the Western Canada natural gas producing, gathering, processing and transportation system and the impact that the operations and commercial management of that system will have on the natural gas fired power generation facilities.

Natural Gas Requirements for Power Generation

It is anticipated that natural gas fired electrical power generation would require between 1.1 Bcf/d (6,300 MW) and 1.7 Bcf/d (10,000 MW) of natural gas supply over the next 10 to 15 years. This is a significant volume of natural gas; system modifications will be required to receive and transport the natural gas on the sales gas systems.

The following figure shows the relationship between electrical power generated and the required natural gas supply.

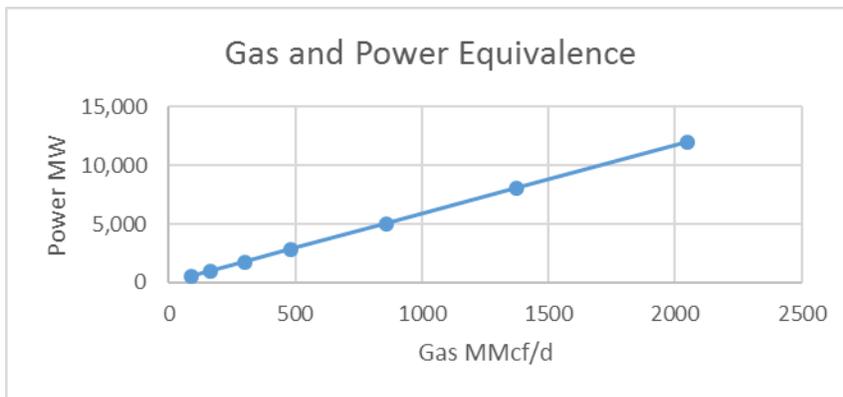


Figure 10.1: Gas and Power Equivalence

Natural Gas Resource

As summarized in Section 1 of this analysis, the NEB EF 2016 Reference Case expects Western Canadian natural gas demand to increase to 13.4 Bcf/d in 2040 from 9.1 Bcf/d in 2015. That analysis further forecasts that natural gas used for Electrical Generation in Western Canada will increase to 2.6 Bcf/d in 2040 from 1.2 Bcf/d in 2015. If we assume (for a bookend assessment of demand) that the growth in natural gas demand in this sector is due to normal demand growth not related to conversion of some of AB's Coal Fired Power Generation to Natural Gas, 10,000 MW of natural gas fired power generation (at a heat rate of 7.5 GJ/MWhr) would require 1.7 Bcf/d of additional dry gas production. This growth in Western Canadian demand could increase the 2040 requirement from 13.4 to 15.1 Bcf/d or 13% growth. The NEB EF 2016 analysis estimates that Western Canada has between 651 and 1,325 Tcf of remaining Marketable Resource with 855 Tcf in its Reference Case. Based on the upper limit of 15.1 Bcf/d (5.5 Tcf/year) the Reference Case Resource represents 155 years of supply based on that Western Canadian Demand.

With respect to overall Western Canadian Natural Gas Supply (based on the NEB EF 2016 Analysis), the addition of 10,000 MW of natural gas fired Electrical Power Generation will be more than underpinned by the available resource.

Gas Supply System for Power Generation

The addition of 1.1 Bcf/d to 1.7 Bcf/d of natural gas demand over the next 10 to 15 years will require system modifications to receive the gas onto the system (likely development will occur in the areas where the system is already fully contracted), and deliver the gas to up to 15 generation sites¹⁵⁹ at yet to be determined locations. Historically, the system has transported volumes greater than currently transported plus this incremental volume of gas required for power generation anticipated.

The NGTL transportation system reaches essentially all gas producing regions in Western Canada and is able to reliably supply gas to many potential gas generation sites. The system can also be reconfigured and modified to supply areas that are good sites for power generation but currently have inadequate gas supply infrastructure. Providing up to 10,000 MW of natural gas fired power generation capacity to replace existing coal plants over the next 15 years will present challenges to the current gas transportation system; of specific interest will be the system changes required to provide flexibility to react to rapid changes in demand.

The following figure shows the NGTL operations areas; there are five Receipt Areas defined by NGTL:

- Upstream James River (USJR)
- Western Gate (WGAT)
- Eastern Gate (EGAT)
- Northeast (NEDA)
- Oils Sands (OSDA)

On the following figure, the blue area designated USJR and areas further north and west in BC are the gas growth areas in Western Canada. As a result of current and anticipated development activity, the transportation system in this area is currently fully contracted and has limited capability available under current operating conditions as shown on the NGTL Receipt Map dated October 5, 2016¹⁶⁰. As a result, modifications will be required to transport additional gas required for new gas generation facilities on this portion of the system. In June 2016, the National Energy Board (NEB) approved NGTL's 2017 Expansion Project which includes five pipeline loops and two compressor station additions. The expansions will provide substantial new capacity primarily in the USJR and OSDA Delivery Areas to meet customer requests. Similar modifications will be required to transport additional gas on this portion of the system and in areas where future gas fired power generation sites will be located.

¹⁵⁹ The number of generation sites roughly determined on the assumption that the Shepard Generation Plant is a typical size

¹⁶⁰ [http://www.transcanada.com/customerexpress/docs/Receipt_Map_October_5_2016\(1\).pdf](http://www.transcanada.com/customerexpress/docs/Receipt_Map_October_5_2016(1).pdf)

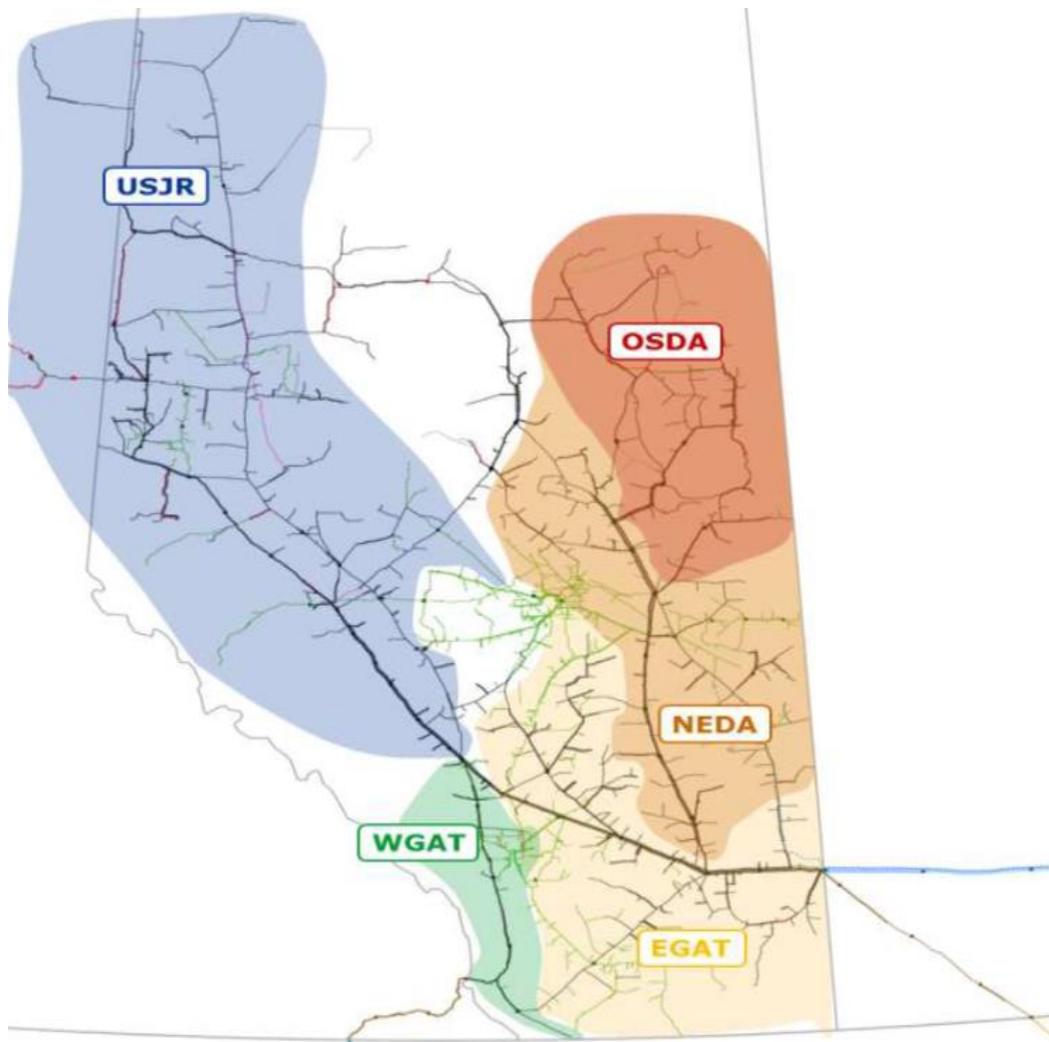


Figure 10.2: –NGTL Operational Areas¹⁶¹

The first step to connect a new gas fired power generation site to the NGTL system to access the required natural gas supply will be the preparation of a delivery point application to initiate the NGTL design process and determine the system design changes required to supply the gas to that delivery point location. Depending on the extent of the modifications and the location of the delivery point, this process can generally take 2 to 3 years to complete. If significant stakeholder or other issues are encountered, it can take an extended period of time to complete the modifications. However, in most situations, if the application for a new gas supply service is requested at the same time as the planning for the power plant project is initiated, the pipeline would normally be completed within the time required to complete the power plant project. However, if the developer is considering a coal to gas conversion for a power generation asset, the conversion time (i.e., 2 to 6 months) may be significantly less than the development of new gas infrastructure if required.

¹⁶¹ Source: NGTL & Foothills Systems – Monthly Outage Forecast – September 2016

System Ability to Manage Volatility

The NGTL system currently handles significant seasonal volatility through operational optimization and the use of storage and line pack. The system compensates for periodic large outages or abnormal operating conditions and maintains supply to customers in essentially all circumstances. The potential to use natural gas for power generation presents additional volatility challenges. For example, a 5,600 MW increase in power demand over a 4-hour period could be anticipated in the future. Assuming this demand increase occurs concurrently over the entire system, the result is a swing of 1 Bcf/d of gas supply that the system would need to accommodate in 4 hours. This is about 10% of the current NGTL system capability. The current system design can manage storage withdrawal swings at a rate of up to 2 Bcf/d. At this time, NGTL monitors the system both hourly and daily and responds accordingly with the use of tolerances to manage the line pack to ensure that variances are mitigated. However, superimposing these large swings (as the result of start-up of substantial natural gas fired power generation) on a system that is designed to manage much smaller weather related swings and larger seasonal variations is untried and is difficult to predict without a more detailed assessment.

With installation of large scale natural gas powered electrical generation, we need to assure the ability of the commercial and physical systems to provide short term fuel supply in response to significant and immediate demand increases (0 to 4 hours) and to continue to provide that natural gas over an extended period of time to operate the power generation facilities (24 plus hours). In addition to the flexibility that the normal physical and commercial operation of the NGTL system provides, the specific power generation facilities could install “pipeline” storage to handle periods of short term fuel shortage or “LNG” storage to handle periods of short term or extended fuel variability or shortage.

Pipeline Storage

For purposes of this analysis, it is assumed that an average sized natural gas fired power generation plant (900 MW¹⁶²) will operate at a minimum of one third of nominal capacity and will be required to increase to nominal capacity in 4 hours. A working natural gas storage volume of 17 MMcf would be required to operate the plant for up to four hours. That on site storage would allow the overall system to adjust to the higher demand and provide flexibility as supply is accessed through the conventional commercial processes from the NGTL system. The storage volume could be contained in a buried pipeline 48 inches in diameter and about 3 miles long positioned along the same right of way as the incoming gas supply pipeline. During the startup of the facility, the gas stored in the pipeline could be accessed to assure the required fuel gas volumes are available; the reverse would occur when the demand is reduced and the storage refilled. Using the cost estimating factor determined in Table 6.2 on page 45 (Section 6) the pipe storage would cost \$33 million (\$2/MMcf of storage)

LNG Storage

LNG liquefaction and storage capacity could be installed at each of the Power Generating Facilities to provide back up for conventionally accessed natural gas volumes for startup and continued operation as required. Currently FortisBC operates two such facilities¹⁶³:

- An LNG production and storage facility on Tilbury Island near Delta, BC (operational since 1971). The facility can liquefy 4.2 MMcf/d of gas with storage capacity for 600 MMcf. FortisBC is

¹⁶² Based on the recently constructed Shepard natural gas fired power generation facility

¹⁶³ From the FortisBC Website and associated press releases

currently expanding the facility to liquefy 32.2 MMcf/d of gas with storage capacity of 1.04 Bcf. The cost for the expansion is estimated at \$400 million and it is planned to be operational in the spring 2017. WesPac Midstream has also received NEB approval for a marine terminal to export 168 BCF/year of LNG sourced from the FortisBC expansion. It appears the two applications are stand alone and FortisBC is proceeding with the expansion.

- A storage facility on Vancouver Island near Ladysmith (Mt Hayes). According to a June 10, 2011 FortisBC press release, this facility has storage capacity of 1.5 Bcf and cost \$200 million. No liquefaction rate was in the press release¹⁶⁴.

Further investigation is required to fully define the operability, capital cost and operating costs associated with the on-site natural gas storage options.

NGTL Commercial Operations

The AB gas market is a success story in how it has adapted to deregulation and the needs of multiple buyers and sellers of natural gas. The market efficiently manages transactions and responses to both over and under supply of natural gas by price signals and adjustments (see Spot Market, Section 8).

As the market grows as anticipated with increased gas power demand market, liquidity will also increase providing more flexibility in the system. In addition, given adequate time to adjust, new products and market operations will develop to accommodate increased demand and the specific requirements of natural gas powered electrical generation. For example, today's market has not been designed to manage unexpected large increase in gas consumption. If 500 mmcf/d of gas was required while the market was closed and not planned for during the gas trading day, it is unclear how today's market would respond to this need. However, if this becomes a new market requirement, the market would need to adapt and develop a solution, (perhaps 24/7 real-time trading).

Short Term Response to Rapidly Changing Demand

The natural gas supply in Western Canada on a short term basis is relatively inflexible. Fluctuations in natural gas demand are generally managed commercially to access the available natural gas supply. Through the trading desks, the fluctuations in demand are met by:

- **Accessing Gas Storage** – During the summer months, injection into the storage reservoirs will decrease or shift to withdrawal as required by changes in demand. As indicated in the preceding Section 9 – Gas Storage, the performance of the storage reservoirs is a function of the amount of gas in storage in the reservoir and the physical productive capacity of those reservoirs. In the short term the physical capacity is an upper limit; in the longer term additional productive capacity (or storage capacity) could be developed to meet market demands.
- **Shifting Gas Export Volumes** – During the winter months when storage withdrawals are at their maximum due to weather driven demand or reduced gas storage withdrawal capacity (as the result of decreased gas storage volumes and the corresponding decrease in withdrawal capacity), an increase in demand will drive up the Western Canada Spot Price. When this occurs, exporters of natural gas to the US will direct natural gas to the market that has the highest net back. Any reduction in export volumes would be met through the purchase of additional

¹⁶⁴The Tilbury Island and Mt. Hayes indicated costs of \$400 million for 1 Bcf of storage and \$200 million for 1.5 Bcf of storage are significantly different. There may be additional facilities included in the Tilbury cost estimate; detail was not publically available to provide further analysis

volumes of natural gas in the US Spot Market to make up any shortfall in exports to that market. In 2015, Canadian Demand was 15 Bcf/d and US Demand was 75 Bcf/d. Accessing 1.7 Bcf/d (10,000 MW) would represent a significant impact on the Canadian market (approximately 10% of total 2015 Demand) with much lower impact on the US Market (approximately 2% of total 2015 Demand). The issue becomes more impactful in the out years of the forecast period as exports to the US are forecast to decrease significantly. In 2015, from the NEB EF 2016, Canada exported a net average of 5 Bcf/d to the US; those volumes are forecasted to decrease to less than 3 Bcf/d in the 2040 Reference Case. The reduction in exports anticipated reduces the ability to commercially shift gas to meet fluctuations in Intra-AB demand.

- **Re-allocation of Intra-Canada Demand** – As with exports, an increasing Western Canada Spot Price for natural gas will result in the shifting of volumes from existing users who have the ability to reduce consumption or shift to alternate fuel sources as the economics dictate.

The concern should not be if the market can adjust to large supply and demand needs but rather what happens if the market become smaller with less buyers and sellers. In this case, large swings in demand will increase price volatility and decrease market flexibility.

Further investigation is required to fully define the hourly and daily Commercial Balancing Process and to identify issues related to the 24/7 management that will be required with the installation of natural gas powered electrical power generation with the expectation of widely varying demand over relatively short time periods (4 hours).

Section 11- Alberta Natural Gas Fired Power Generation Dependability and Reliability

The risks associated with the physically and commercially available natural gas supply can be categorized as follows:

- Western Canada Gas Resource Risk
- Western Canada hourly and daily Supply Risk
- Commercial Access Risk
- Physical Delivery System Risk

Resource Risk

With respect to overall Western Canadian Natural Gas Supply (based on the NEB EF 2016 Analysis), the addition of up to 10,000 MW of natural gas fired power generation will be more than underpinned by the available resource. Anticipated growth of demand for natural gas fired power generation will put upward pressure on the price of natural gas within Western Canada and, given sufficient cycle time, the development of additional supplies of natural gas to meet the long term need.

The largest risk (with a low probability of occurrence) is legislation that prevents or curtails the use of hydraulic fracturing in the completion of tight conventional and unconventional natural gas reservoirs. A change in the regulations would result in a significant reduction in the available economic resource, an increase in the cost of natural gas development and the resulting price of natural gas in Western Canada and the US.

Supply Risk

Natural gas movement through the NGTL systems varies over time as demand and supply changes. On a short term basis, natural gas supply is fairly inflexible to daily variations. The following figures shows the natural gas supply for the period 2008 to 2015 with daily changes in natural gas storage injection and withdrawals. During the period, storage injection and withdrawals vary by up to 4 bcf/d depending on the season and whether injection or withdrawals are at maximum volumes. During the same period, NGLT Field Receipts are fairly tightly bounded with fluctuations in the range of 1 bcf/d.

Daily Supply Changes From Storage

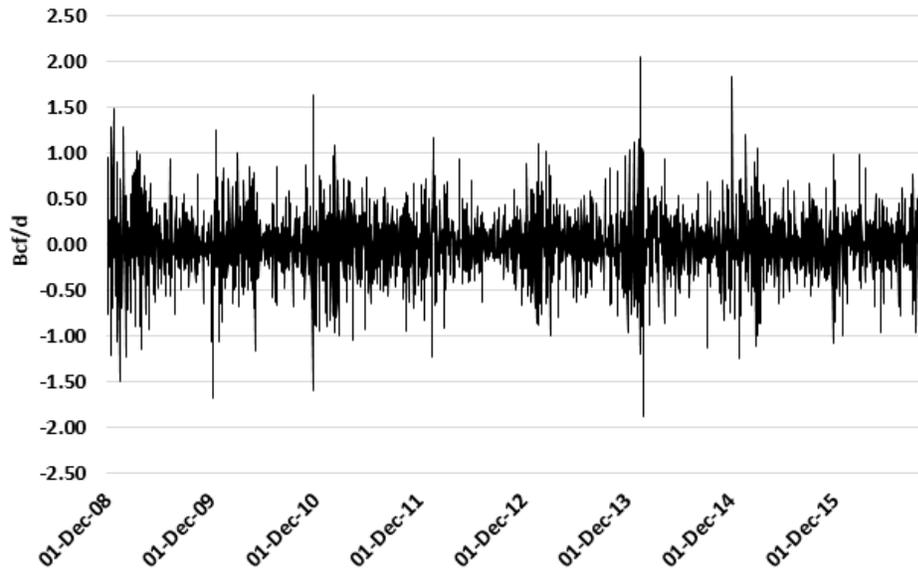


Figure 11.1: Daily Supply Changes from Storage 2008 to 2015¹⁶⁵

NGTL Field Receipts

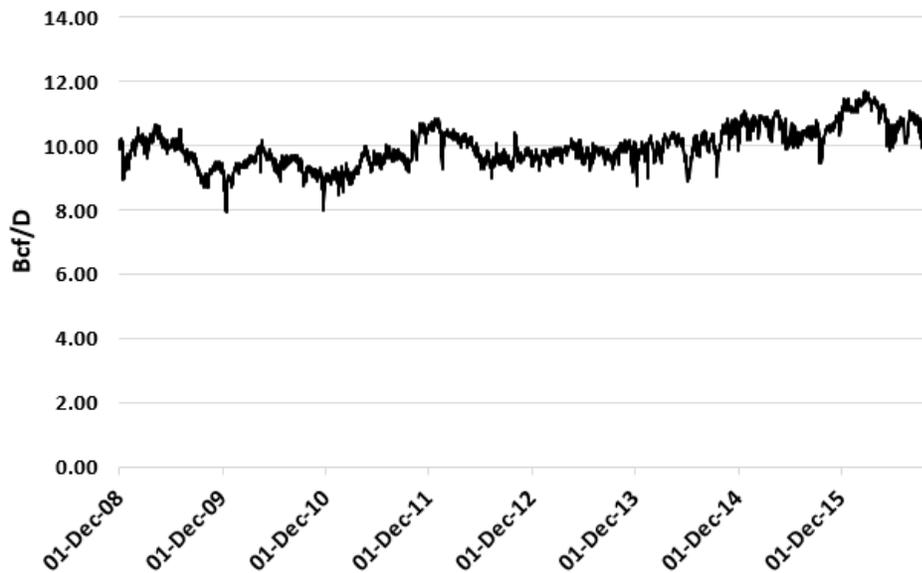


Figure 11.2 : NGTL Field Receipts 2008 to 2015¹⁶⁶

Short term variations in natural gas demand are met by natural gas withdrawals from storage, re-allocation of natural gas exports or re-allocation of intra-Western Canada Demand.

¹⁶⁵ NGTL Gas Day Summary: <http://www.transcanada.com/customerexpress/gasdaysummaryreport.html>

¹⁶⁶ NGTL Gas Day Summary: <http://www.transcanada.com/customerexpress/gasdaysummaryreport.html>

Commercial Risk

The primary risks to the operational supply are:

- Interruption to the physical natural gas supply
- Inability of withdrawals from natural gas storage to meet demand variability
- Inability of natural gas export volumes to be re-allocated to meet demand variability
- Inability of Intra-Western Canada other demand sources to be-reallocated to meet demand variability

The risks to the supply are magnified by seasonal demand differences and weather related operational problems and are a function of the ability of the market to react to wide variations in demand. The potential variability is dependent upon the total amount of natural gas fired power generation (5,600 MW could require 1 Bcf/d and 10,000 MW 1.7 Bcf/d) and the amount of base load that is operational at any given time. The analysis can be broken down into three general periods:

- **Period 1** - Natural gas storage reservoirs are on their injection cycle (generally late spring, summer and early fall – natural gas demand is less than supply). Wide fluctuations in demand (up to 4 Bcf/d – full injection to full withdrawal) can reasonably be met by decreasing injection rates or shifting to withdrawal. Generally, disruptions in the physical gas supply are as the result of planned curtailments; the risk of unplanned outages is relatively low.
- **Period 2** - Natural gas storage reservoirs are early in their withdrawal cycle (general early winter – natural gas demand exceeds supply). As discussed in Section 9, generally the natural gas storage withdrawal rates are at their maximum as the reservoirs are re-pressured. The risk of unplanned disruptions in the physical gas supply increases with cold weather caused operational issues.
- **Period 3** - Natural gas storage reservoirs are late in their withdrawal cycle (generally late winter – natural gas demand exceeds supply). As discussed in Section 9, generally the natural gas storage withdrawal rates are dropping as the storage volumes in the reservoirs are drawn down. The risk of unplanned disruptions in the physical gas supply increases with cold weather caused operational issues.

Gas supply risk is highest during the above Period 3, shortages in gas supply would result in an increased Western Canada spot price and a shift of gas supply from export and other Intra-Western Canada demand in the response to shifts in net backs. The ability to shift demand decreases as export volumes drop and a higher percentage of demand is focused on electrical power generation. NGTL integration with gas storage provides significant capacity to balance daily demand variations. Historical withdrawal rates have exceeded 2 Bcf/d with day-to-day variations of up to 2 Bcf/d. However, it is unclear if today's storage infrastructure could respond to an additional 1 Bcf/d of unplanned demand under these conditions. To better understand storage withdrawal capacity limitations in extreme conditions requires additional research. Additional withdrawal capacity and/or storage facilities could be developed. As these facilities are merchant operated, they are driven by market conditions and corporate profits. Therefore, the capacity will only be expanded if the market is willing to bear the cost of these expansions. With the need for storage for export declining, the current storage market is soft with AB

working gas levels above the five-year average¹⁶⁷. It is unlikely additional storage facility or expansions will be developed in the near term.

These risks are mitigated by the installation of on-site storage (LNG), assuring commercial access to available gas storage withdrawal volumes or fuel switching. On site storage options have been discussed in Section 10.

In addition, currently natural gas trading and commercial access to available supply does not occur in the off hours when the market is closed. The requirement to rapidly increase the demand for natural gas for electric generation is independent of the trading day. Further investigation of hourly and daily trading and balancing and analysis of how the market could respond to 24/7 operation is required.

Commercial Access to Gas Storage Capacity

Ensured access to available Gas Storage Capacity could be commercially assured by entering into priority storage and withdrawal rate contracts. With this type of Gas Storage Contract, priority access to available volumes would be assured and not subject to the ability to purchase the natural gas on the Western Canada Spot Market as required.

Fuel Switching

Depending upon the design of the Power Generating Facility, it may be possible to provide an alternate fuel back up to natural gas in the event that natural gas is not available. Further investigation is required to fully define the fuel options, operability, capital cost and operating costs associated with assured commercial access to the gas storage reservoirs and fuel switching.

Physical Delivery System Risk

Generally, risks in the physical system are minimal. Production and gas processing capacity is wide spread, significant transportation capacity is present, any required pipe or system changes are doable and the processes that are required to make system changes are in place and able to respond in the time frames required. However, supply disruptions do occur in the physical system and can be classed as Planned and Unplanned.

- **Planned** - Planned disruptions occur as facilities and gas transport systems are taken out of service for maintenance. These tend to occur during the warm weather months when Gas Storage reservoirs are on their injection cycle. As a result, overall reduction in system supply is not a major risk.
- **Unplanned** - Disruptions in supply can occur as facilities or transport systems experience operating or equipment problems and require emergency maintenance. Due to the nature of the occurrences, pre-planning is not possible and supply disruption can occur. Due to the size and duplication of facilities and pipelines, any disruption is likely small relative to overall demand and can be met by the adjustment of Natural Gas storage injection/withdrawal volumes. The impact can be magnified as the probability of disruption increases with cold weather when Natural Gas storage withdrawal rates are potentially at their maximum.

Mitigation to delivery system issues are on site storage of natural gas (pipe or LNG), priority access to Natural Gas storage or withdrawal volumes or fuel switching as have been discussed prior.

¹⁶⁷ Based on GPMi intelligence.