CONTENTS

FOREWORD: DAVE NIKOLEJSIN, DEPUTY MINISTER

It takes a special kind of company to invest in British Columbia's oil and gas industry, one that will be enthusiastically committed to community engagement and environmental performance with the capacity required to meet these jurisdictionally unique objectives. For those who make the concerted effort to align their corporate principles with British Columbia's environmental, social and governance values, there can be significant rewards – particularly through the development of the prolific resource in the Montney formation, in the Province's northeast region.

The primary headwind for B.C. natural gas producers is finding a market which will buy the natural gas for a price that will justify new investment. Current provincial production has grown to the point that pipeline egress is at or near capacity. There is some new capacity coming online that will feed into the Nova Gas Transmission, Limited (NGTL) system, but the end markets accessed via NGTL are over-saturated in low cost natural gas coming from all over North America. The massive oversupply of natural gas in North America will continue to suppress the North American hub pricing and with B.C. being furthest from most of the major demand centres, it will continue to receive the largest transportation related discount to the North American hub price relative to competing jurisdictions.

A large proportion of the Montney play is liquids rich, which means that when the natural gas is produced it also yields high value natural gas liquids (NGL's). In some situations, the quantity and value of these NGL's can justify the investment in a new gas well alone, without the need to realize any value for the natural gas at all. This is one of the contributing reasons for historically low natural gas prices; new gas wells are continually drilled and brought onto production despite the oversupply and egress constraint.

British Columbia and the entire Western Canadian Sedimentary Basin (WCSB) is in a globally unique situation where upstream investments are justified despite low natural gas prices and in turn, can provide low cost feedstock to liquefied natural gas (LNG) export facilities on the west coast. However, it should be noted that the development of LNG as well as market diversification for NGL's is a necessity for WCSB producers. Without the expansion of new markets for all products, there will be a contraction in the amount of investment activity that occurs in the upstream natural gas sector in Western Canada. The first phase of LNG Canada is the minimum new demand required to sustain activity at current levels in British Columbia.

There is significant potential value in WCSB light hydrocarbon resource that could be lost if markets beyond North America are not developed. B.C. is well positioned to provide energy to Asian markets that will provide a net reduction in global carbon emissions, but we need to compete vigorously to secure international market share and in turn, long term value for what is arguably the most environmentally and socially responsible natural gas in the world.

INTRODUCTION: INVESTMENT COMPETITIVENESS OF BRITISH COLUMBIA'S NATURAL GAS INDUSTRY

Among its competitors in the North American oil and gas sector, British Columbia has a unique, diverse story to share. Canada's western-most province is blessed with vast natural resources and an inspiring, cherished natural environment. Respect for Indigenous human rights is bound by newly adopted provincial legislation. It ensures Indigenous peoples are part of the decisions that affect them and that economic opportunities benefit all communities, while protecting land, air and water.

Over time, the B.C. economy has been driven by traditional resource industries such as forestry and fisheries. Many of its earliest settlers came in search of gold.

By comparison, oil and gas activity is a relatively new contributor to the province's prosperity. Development first began in the 1950s – about 80 years after B.C. became part of Canada. Activity has leapt dramatically over the past two decades, with most of the production in the northeast region of the province.

The goal of this study is to quantify B.C.'s investment potential compared to other key jurisdictions that compete for capital from similar sources, for similar activities within the North American natural gas and natural gas liquids market. Jurisdictional comparisons require a fairly high-level geological and engineering assessment of the resource, in turn allowing for assessments of specific government policies. This assessment uses current information and data that were available as of August 2019.

For comparative purposes, the neighbouring province of Alberta is a key jurisdiction. Most companies considering investments in B.C. are headquartered in Calgary and are likely to be more familiar with opportunities in their own backyard. Also, with Alberta and B.C. subject to the same federal government oversight, direct comparisons are relatively easy to make.

United States jurisdictions, with some structurally different attributes, are more difficult to assess. However, comparisons to certain jurisdictions in the U.S are useful. The plays and jurisdictions evaluated in this study are the Montney in Alberta, the Marcellus in Pennsylvania and the Permian in Texas.

The substantial level of investment in U.S. plays over the past 10 years has brought a dramatic shift in global energy markets and has completely disrupted the North American hydrocarbon supply balance. In that time, the U.S. has gone from a net importer of natural gas to a net exporter. Canadian natural gas producers can no longer rely on the U.S. as the insatiable demand sink it once was for Canadian energy. In addition, the Marcellus lies in proximity to the key demand centre of the Eastern seaboard, which garners a significant transportation cost advantage over Canadian plays.

The U.S. is now self-sufficient and is outcompeting Canadian gas for key, historically held demand markets. It is expected to continue to expand its share of the North American market. Oil drilling in the Permian has exacerbated North American oversupply by growing the associated natural gas production. As associated gas is a by-product of oil production, the supply cost is very low and drives the hub pricing down, further reducing the economic viability of new natural gas investment in Canada.

B.C. has performed well through the latest down cycle in the industry, due to the prospect of LNG exports and strong well performance, but the level of activity and production growth pales in comparison to the U.S. plays.

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The goal is to be as quantitative as possible by solving for a common cost metric which could be compared across jurisdictions, specifically the cost in $CAD per unit volume of production. Using oilfield units of thousand cubic feet (mcf), gives us a common $/mcf metric for comparison. Not all variables relating to investor competitiveness can be translated to the $/mcf metric, therefore other factors like timing and uncertainty were quantified on more of a qualitative basis.

The B.C. Ministry of Energy, Mines and Petroleum Resources conducts biannual resource and royalty competitiveness studies for internal purposes. This report expands that scope significantly by providing stakeholders and interested members of the public with a review of broader policy initiatives associated with the Province's position as a destination for oil and gas investment opportunities. Pursuant policy recommendations are not included in this document.

1. RESOURCE BASE

British Columbia's natural gas resources are among of the largest in the world and offer a low cost of supply for the next decade. This positions B.C. to be a competitive liquified natural gas supplier.

In particular, the Montney Formation is a large contiguous resource with tremendous potential for both natural gas and associated hydrocarbon liquid production. It is spread across both dry and liquids-rich bearing regions from northeast B.C. and stretches into Alberta.

While there are multiple prolific resource plays in North America that compete for both capital and market share, the Montney is somewhate challenged by geography, however it contains physical characteristics that make development economically viable. When comparing B.C.'s resource to other jurisdictions, the B.C. Montney play is highly competitive.

1.1 RESOURCE AND COST OF SUPPLY

A 2019 study prepared for the Ministry of Energy, Mines and Petroleum Resources by McDaniel & Associates Ltd. (McDaniel) predicts the future supply and development potential of the B.C. Montney. The approach, interpretations, analyses, charts, graphs, and estimates presented in this section are designed, calculated, and interpreted by McDaniel.

The study determined the total B.C. Montney economic resource exceeds 400 trillion cubic feet (Tcf) of marketable gas, substantially more than the 2013 National Energy Board (NEB) ultimate Montney potential estimate of 271 Tcf marketable gas. The undeveloped raw gas remaining in the B.C. Montney could support an inventory of over 45,000 wells in the lower, middle, and upper Montney benches.

The study also found that nearly 200 Tcf of economic B.C. Montney gas at a benchmark AECO Supply Cost of C$1.00/MMBtu. At 2019 production volumes, McDaniel's analysis indicates 100 years of B.C. Montney gas available below an AECO supply cost of C$1.20/MMBtu. B.C. Montney supply costs are competitive when compared to the Alberta Montney, Duvernay, and Spirit River plays.

The increased resource estimate compared to the NEB's 2013 study results from multiple factors including a new approach used to estimate unconventional resources, increased B.C. Montney activity, stacked vertical Montney targets, improved recovery assessments, and advances in drilling and completions technology and design. Previous models were designed to estimate resources in conventional reservoirs, and a new approach to estimate unconventional Montney resources has been utilized here.

McDaniel determined the B.C. Montney supply and total resource potential using a new modeling approach that combines geological and reservoir characterization, decline analysis, volumetric analysis, visual analytics, and machine learning analysis.

SUPPLY SUMMARY

The B.C. Heritage and Northern Montney regions have been divided into 30 subareas to account for performance differences due to geographical location and liquids content. A detailed geological interpretation provided reservoir characterization in the Upper, Middle, and Lower Montney benches in each subarea. This was combined with analysis of current producing wells and recent completion trends.

The supply potential is described as "discovered resources," which can be considered either reserves or contingent resources and "undiscovered resources", which can be considered prospective resources. To be designated as discovered resources, any future inventory must be within three miles of existing productive well control in a given development bench.

McDaniel estimates the total undeveloped raw gas in the B.C. Montney to be 413 Tcf. In addition to the undeveloped volumes, developed (Proved (P) + Proved Developed Producing (PDP)) volumes from existing wells are 21.7 Tcf. Total discovered raw gas is estimated to be 262 Tcf and total discovered and undiscovered raw gas is estimated to be 434 Tcf.

McDaniel calculated future resource inventory based on an AECO gas price of $3.00/MMBtu. Operating and capital cost structures used are representative of current market conditions for commercial Montney operations developed with pad drilling and long-term marketing agreements.

Type curves and remaining inventory were calculated for the 30 Montney subareas and within each area, the Montney was separately considered in the Upper, Middle and Lower stratigraphic zones.

For the resource base supply summary see Appendix C.

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Page 008 of 110 to/à Page 009 of 110

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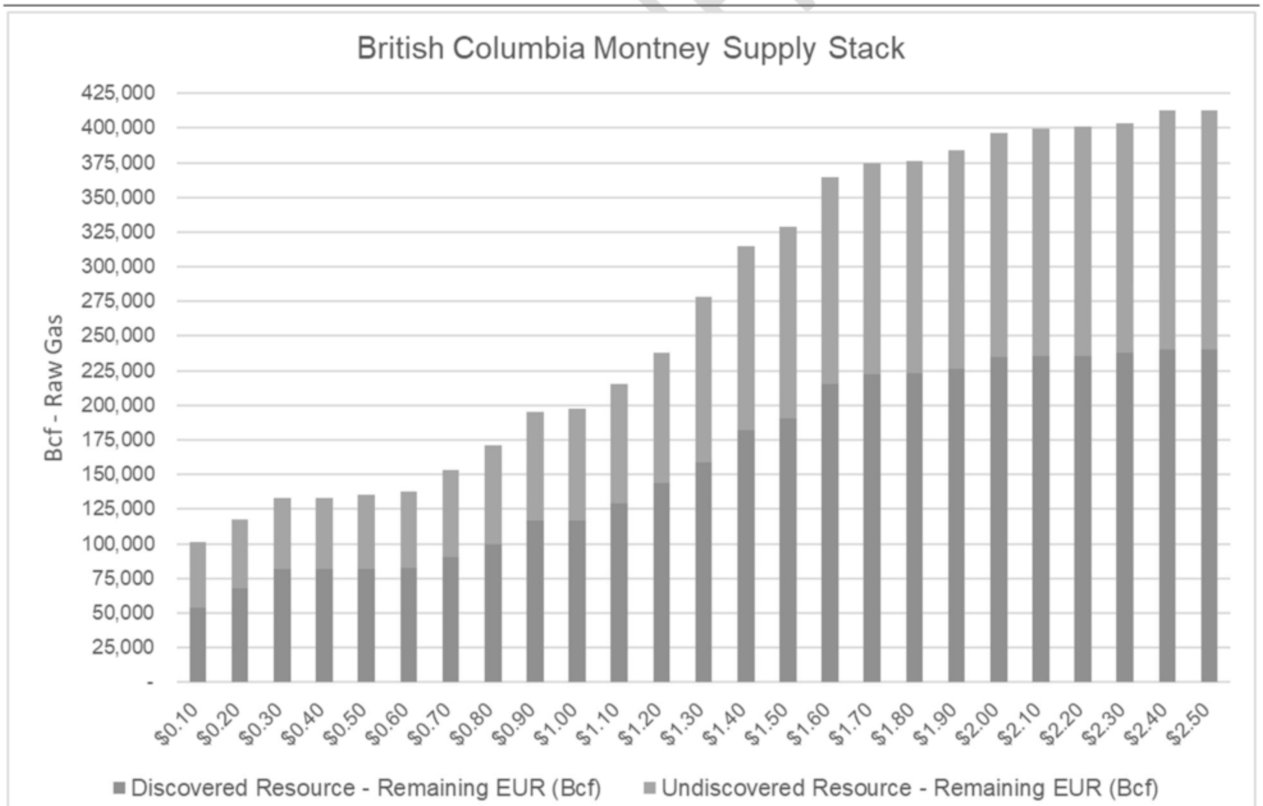
BREAK-EVEN SUPPLY COSTS

Based on supply volumes and break-even costs, McDaniel created a supply stack showing the "discovered" and "undiscovered" resource available at varied levels of AECO pricing. Area type curves were generated on an area and stratigraphic basis (Upper, Middle, and Lower Montney). McDaniel created the type curves on a combination of volumetric analysis and Machine Learning analysis which, resolved the optimal development strategy based on economic optimization. McDaniel used a long term AECO price of $3.00/MMBtu (2019$) and long term WTI of $67.50/bbl (2019$) to determine ultimate well density. A minimum 10 percent rate of return on all wells was applied to be included in the assessment as economic.

The break-even analysis was performed on the optimized curves. The AECO gas price was varied while all other price and cost variables were held constant at 2019 prices from the McDaniel January 1, 2019 price forecast. These break-even costs were used to create the supply curve.

McDaniel's analysis indicates a Montney gas resource equivalent to 100 years of B.C.'s 2019 production volumes below an AECO supply cost of C$1.20/MMBtu. The B.C. Montney supply stack shows nearly 200 Tcf of economic B.C. Montney gas at an AECO Supply Cost of C$1.00/MMBtu

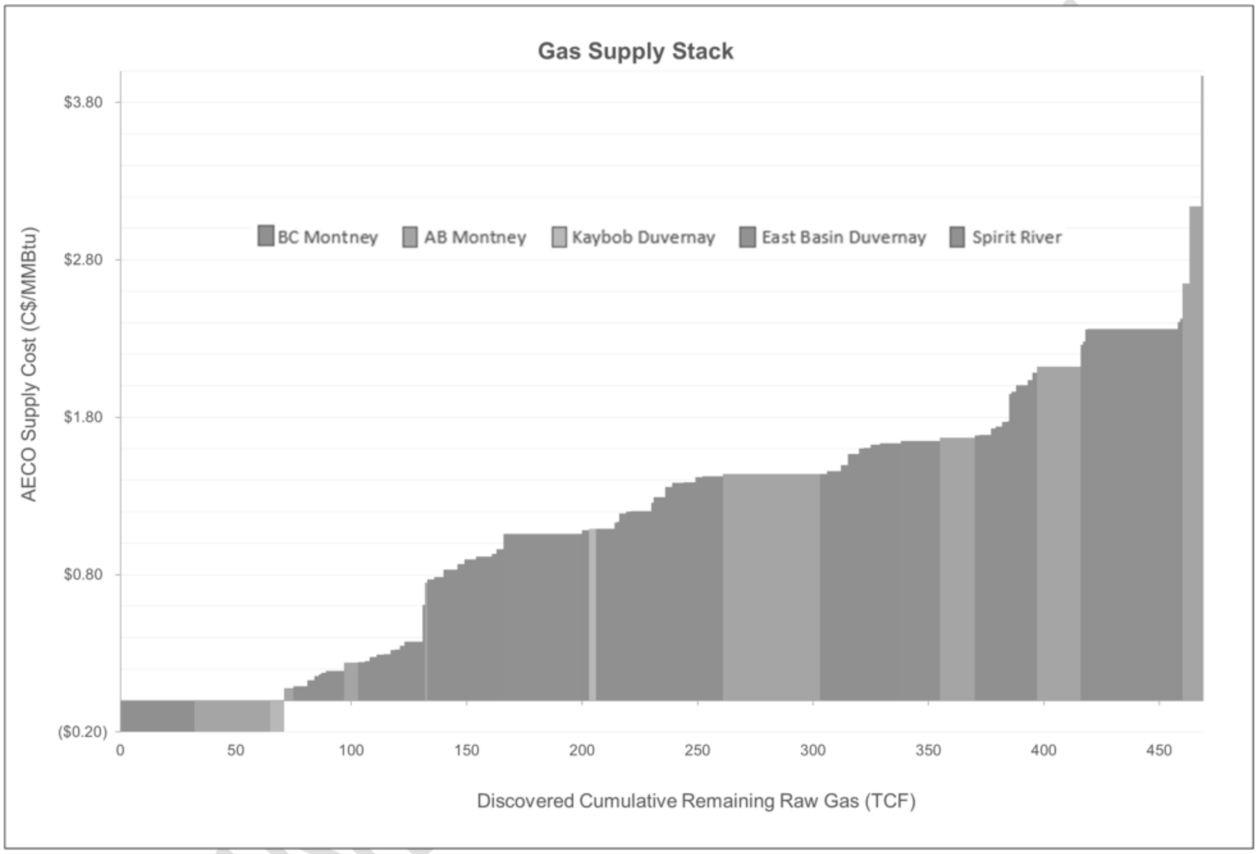
B.C. MONTNEY SUPPLY CURVE (MCDANIEL, 2019)



COMPETING WESTERN CANADIAN SEDIMENTARY BASIN (WCSB) PLAY COMPARISON

To compare the volumes and economics of the B.C. Montney resource with competing Canadian unconventional gas resources, McDaniel prepared a high-level summary of the Alberta Montney, Duvernay, and Spirit River supply potential. The B.C. Horn River was not included in this analysis as initial assessments indicated a large departure in economic performance from the other plays. The competing formations did not involve detailed geological interpretation and McDaniel cautions that the analysis should be considered directional in nature. The break-even analysis was run with the same set-up as the B.C. Montney.

B.C. MONTNEY AND COMPETING PLAYS SUPPLY STACK (MCDANIEL, 2019)



The B.C. Montney Formation contains a thick, tight gas and natural gas liquids play within over-pressured siltstones. It can reach 300m in thickness and contains multiple vertically stacked, horizontally targeted sub-horizons in the upper, middle, and lower zones.

The B.C. Montney supply curve and break-even analysis indicates that B.C. Montney gas is competitive in western Canada and well positioned to supply gas to the LNG market under various demand scenarios.

1.2 RESOURCE COMPARISON

North American basins producing unconventional gas and international basins producing offshore conventional gas (allocated for LNG) are profiled and compared based on their geological and resource characteristics. The selected North American basins were chosen for comparison because they are similar in output, economic significance and amount of readily available information on important resource parameters. In addition to the North American competing plays, information was compiled to evaluate various LNG supply areas for their resource potential.

Data was collected for basin qualities; area thickness, depth below surface, average organic content percentage, CO2 and H2S percentage, remaining reserves and technically recoverable resource (TRR). The geological factors combine to determine whether a basin will be productive. All basin results can be found in Appendix A however for the purpose of this section our comparison is focused on the TRR.

The results reveal that the Montney Play Trend of northeastern B.C. has the most technically recoverable gas resource of any plays evaluated in North America. When comparing LNG supply basins, the B.C Montney TRR is very large (400tcf), only trailing the Qatar North Field (900tcf).

Many North American shale basins produce gas at this time, but those selected for comparison are similar in output, economic significance and the amount of readily available information on important resource parameters. Outside of North America, few if any, unconventional shale basins produce shale gas for possible export as LNG; so, the overseas basins examined are offshore and conventional. All offshore facilities examined currently produce LNG for export; only a few of the onshore shale basins currently produce gas specifically for LNG, either directly or indirectly.

Information for this review originates mainly from online sources. The amount of information varies greatly depending on jurisdiction and stage of development. The characteristics chosen were able to be used for comparison in all chosen jurisdiction.

Two tables were compiled with the chosen characteristics. Table 1: *North American Unconventional Basins* and table 2: *Offshore Conventional Basins.* The tables can be found in Appendix A for reference. The main characteristic of focus for comparison is the TRR.

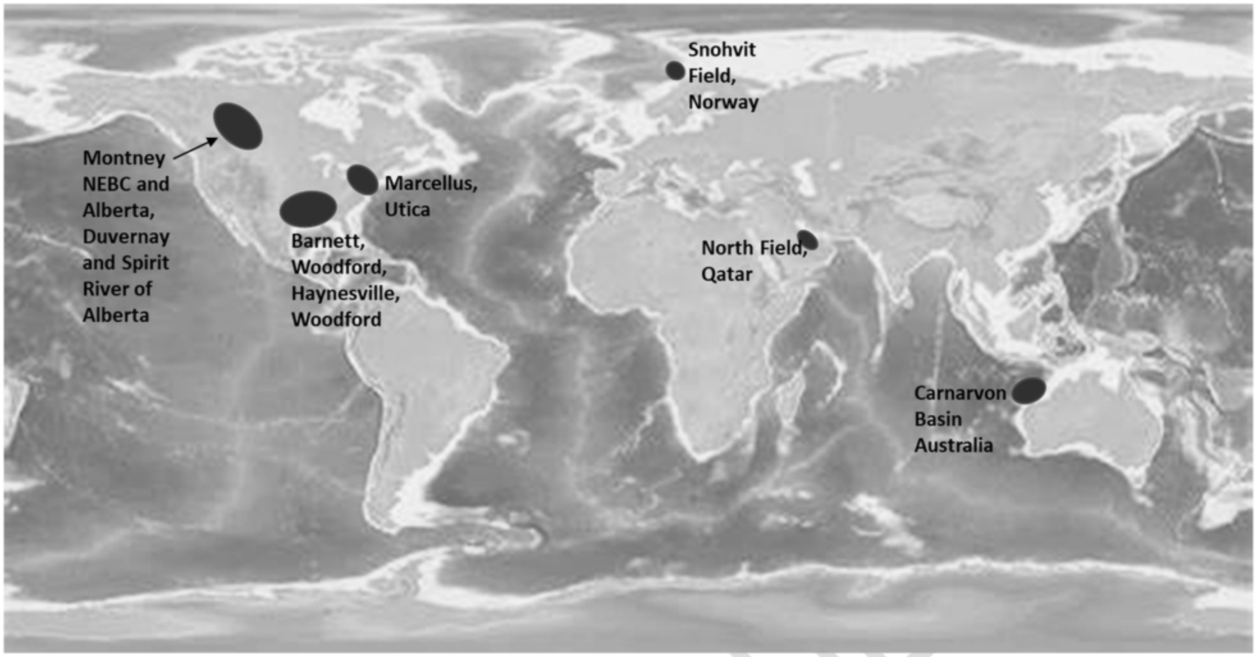


Figure 1 - North American Unconventional Shale Basins and International Offshore LNG Producing Basins

Shale basins differ dramatically from offshore conventional plays. New technologies can make shale basins highly productive even when geological conditions are less than optimal. By contrast, offshore conventional plays will not produce efficiently no matter what technology is applied if the geology is unsuitable.

Output per shale gas well is low when compared to the offshore, but predictable. Many wells, and constant drilling, are needed to sustain or increase production from a shale gas field because production declines quickly from individual wells. Offshore conventional gas fields can produce prodigious amounts of gas from a handful of wells that have slow decline rates. Offshore wells are very expensive, but few are needed.

Shale wells have nearly a 100% certainty of success, whereas conventional wells are much riskier and usually require considerable exploratory effort. Ultimate potential for a shale gas field can be estimated with a reasonable level of accuracy because total shale volume can be measured, and recovery is essentially proportional to the amount of organic rich sedimentary rock. No such certainty is possible for the conventional; but successful exploration can lead to new discoveries and greatly increased production from only one or two wells.

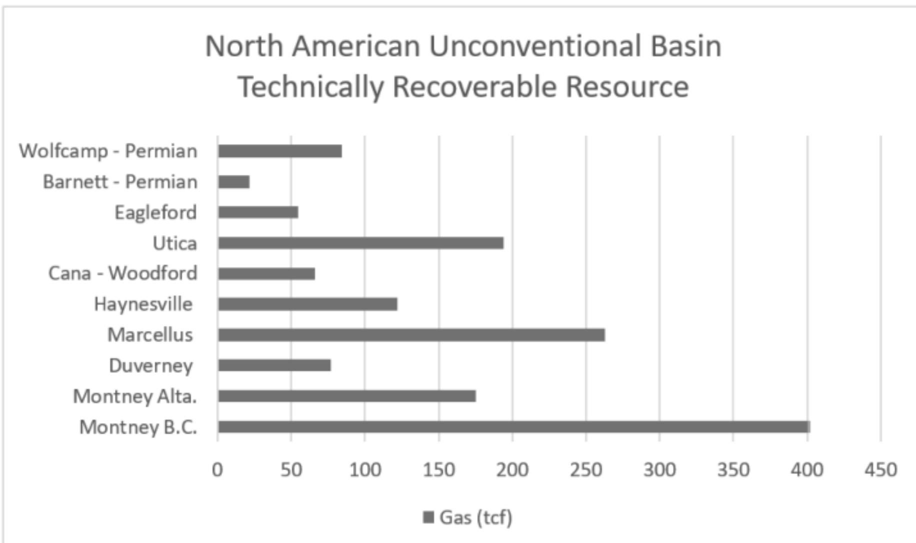
North American Shale Basins

Shale basins where uncoventional gas production exists are large in area, thick and are similar in TRR. Despite the wide geographic spread of North American shale basins, they share many comparable values in terms of TRR in proportion to their size. Differences in geological and production characteristics for the basins examined appear to be subtle. Variations in reservoir quality within basins make it difficult to generalize overall quality. Technology, and experience in applying it, have provided a levelling effect and tends over time to neutralize differences. Wells in all basins profiled produce gas within a narrow range, and well costs are not vastly different because depths and geological conditions are similar.

Montney Play Trend of Northeastern British Columbia

Gas has been produced unconventionally from the Montney Formation in British Columbia since around 2007 and since that time has dominated upstream activity in the Province. In terms of recoverable volumes, it ranks with some of the biggest shale gas plays in the world, TRR of 400tcf. Reservoir rock is composed of variable siltstone, shale and dolomitic siltstone. Siltstones, and not shales, are the dominant lithology. Porosities range between 2 – 9% [1]. It thickens to the southwest where it may have three or four segregated, over-pressured, sub-horizons provide separate target intervals. To the northeast pressure lessens and the gas carries a higher proportion of natural gas liquids (NGL). Clay content is low, and silica is high, so it is brittle and conducive to being hydraulically fractured.

Other play profiles, (including Alta., U.S., Australia, Qatar, and Norway) geological and resource summaries and can be found in Appendix A

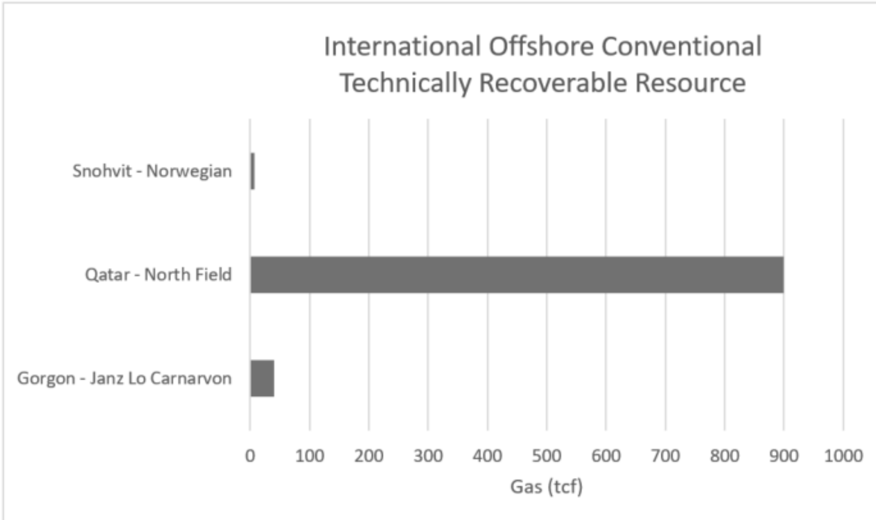


Offshore Producers supplying LNG

Offshore fields are generally much smaller in extent and vary greatly in TRR. They need far fewer wells to be economical. All three of the offshore LNG basins profiled here produce gas from distinctly different conventional geological play types. Unlike the unconventional, factors such as organic content or brittleness are not essential features. Conventional plays are sourced by separate and sometimes distant organic-rich formations, and conventional rock formations do not need to be stimulated because they have the porosity and permeability to flow on their own. Effective application of technology can make a difference in how well these fields produce, but it cannot overcome or compensate for intrinsically less favourable geological characteristics.

Production per well is far higher than an unconventional well. A small number of wells can produce the equivalent of hundreds of shale gas wells. However, cost per well is far greater, and that doesn't include expensive exploration programs needed to pinpoint drilling locations.

Of the three jurisdictions evaluated, Qatar's North Field basin is significantly larger TRR at 900tcf than the smaller Australian Gorgon -Janz Lo Carnarvon basin 40tcf and the Norwegian Snohvit basin, 7.4tcf.



For an unconventional field to be economical it primarily needs size, depth, thickness, some degree of brittleness and organic content. Those conditions exist in many basins in North America.

Conventional offshore producers of gas for LNG are fundamentally very different geologically and performance varies greatly depending on the geology. Intense exploration efforts are needed to find the right set of geological conditions.

2. RESOURCE ACCESS

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2.1 TENURE DISPOSITION PROCESS EFFICIENCY

British Columbia's Montney petroleum and natural gas (PNG) resources lie within an area of important First Nations, social, and environmental values. To access this resource, B.C. has developed a PNG tenure system unique from competing resource areas. Greater than 95% of subsurface PNG resources in northeast B.C. are owned by the Province, resulting in a clear and consistent PNG tenure disposition and management process.

B.C.'s pre-tenure consultation and referral process identifies potential issues that may impact the development of PNG resources and thereby reduce the associated risk and uncertainty for proponents, First Nations, stakeholders, and local communities. In localized areas, lands requested for posting may be deferred from disposition due to government planning processes, community interests and First Nations agreements, processes and legal challenges. However, over the past decade, 90% of lands in the Montney fairway have been offered for disposition within two months of the requested sale date. In B.C., PNG tenure management systems are client-focused and provide information and support to industry while fulfilling the requirements of government.

The PNG industry in B.C. is currently focused on the exploration and development of the Montney unconventional gas play. To access the resource, B.C. has developed a tenure system unique from competing jurisdictions. Each aspect of the PNG tenure system has a distinct approach designed to support industry and protect important values. In this section, northeast British Columbia's PNG tenure disposition and management process is compared with four North American unconventional resource areas: Alberta (Alta.), British Columbia (B.C.), Pennsylvania (PA), and Texas (TX).

PETROLEUM AND NATURAL GAS SUBSURFACE RIGHTS

Most subsurface PNG resources in B.C. are owned by the Province. This results in a clear and consistent PNG disposition and tenure management process. Similarly, in Alta., the Crown owns a high percentage of subsurface PNG rights. As a result, there is no need for a mechanism to resolve subsurface ownership disputes, which can and does occur in other jurisdictions.

In comparable unconventional resource areas in the U.S., subsurface PNG rights are predominantly freehold. In PA and TX, the mineral estate is privately owned and an individual or company may negotiate a lease and royalty payment or agreement with the owner. This form of tenure requires an assortment of acquisition processes. Due to the difference in primary tenure types, tenure disposition in the U.S. is not comparable to the processes in B.C. and Alta. and is not discussed further. The information in the two tables below outlines the differences in tenure disposition and continuation between four resource areas.

PNG TENURE COMPARISON

Resource Area	Primary Tenure	Freehold Rights	Posting Request	Pre-tenure engagement	Disposition Process	Rights Available
Alta.	Crown	19%	4 days+	screening	auction	Lease/ Licence
B.C. (NE)	Crown	< 5%	2 weeks+	yes (unique)	auction	Lease/ Licence
PA	Freehold	90^	NA^	NA^	private agreements	Lease
TX	Freehold	90^	NA^	NA^	private agreements	Lease

^ *The remaining estimated 10% of Federally controlled lands are not considered in this analysis*

PNG TENURE COMPARISON (CONTINUED)

Resource Area	Rights Available	Fees	Bonus Bids	Tenure Security	Continuations
Alta.	Lease/ Licence	Issuance fee: $625, annual rent: $3.50/ha (lease & licence)	low minimum	type wells/zone designations	proven productive
B.C. (NE)	Lease/ Licence	Issuance fee: $500, annual rent: $7.50/ha (lease), $3.50/ha (licence)	SDM * discretion	type wells/zone designations	not production dependent (delimit a pool)
PA	Lease	Negotiated lease agreement, royalty payment 1/8 production value	variable	performance requirements	performance requirements
TX	Lease	Negotiated lease and royalty agreement	variable	performance requirements	performance requirements

** Statutory Decision Maker (SDM)*

PNG REFERRAL AND DISPOSITION PROCESS

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s.13 The Province considers the rights and interests of First Nations, the ecological area and the concerns of local communities prior to posting PNG rights for disposition.

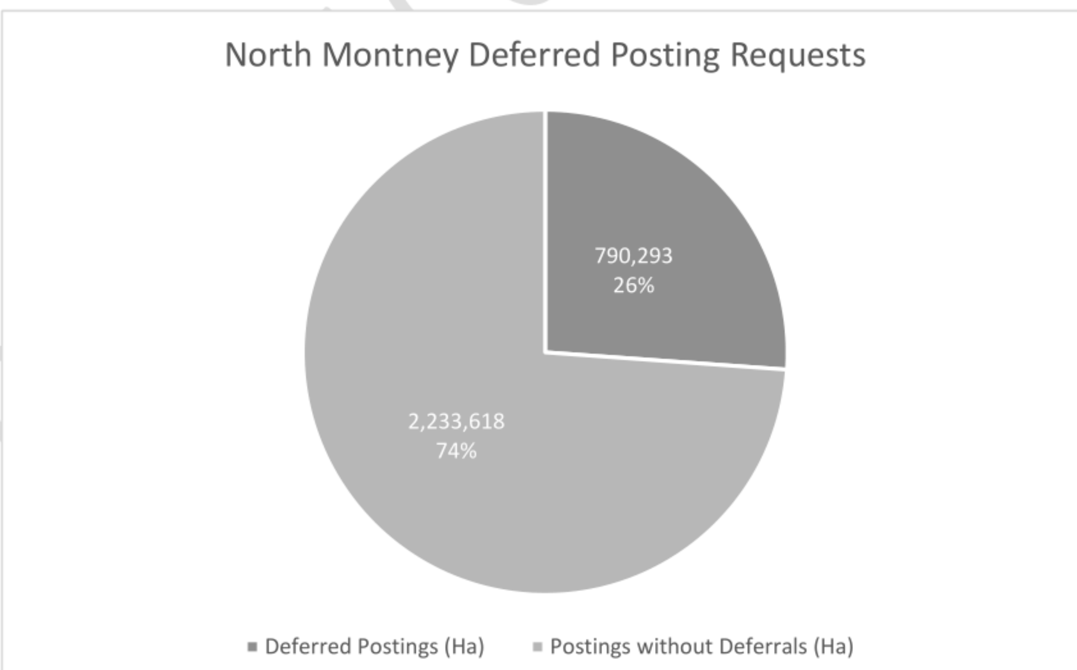
On Nov. 26, 2019, the B.C. Legislature unanimously approved Bill 41, the *Declaration on the Rights of Indigenous Peoples Act*, a commitment to implement the principals of the United Nations Declaration of Rights of Indigenous Peoples (UNDRIP).

All the PNG producing lands in northeast B.C. are within the traditional territory of the Treaty 8 and other First Nations. As a result, the Province engages in a comprehensive pre-tenure consultation process and enters into agreements and processes with the First Nations. In support of these agreements, the Province and Treaty 8 First Nations are currently examining the cumulative effects of industrial development (including PNG) in respect to their rights and livelihood.

When PNG tenure is requested for disposition, the Ministry of Energy, Mines and Petroleum Resources (EMPR) carries out a thorough referral process to identify potential issues that may impact the development of PNG resources and reduce the associated risk and uncertainty for proponents, First Nations, stakeholders, and local communities. The referral process allows EMPR to provide notice to proponents of resource access issues and considerations prior to purchasing the PNG rights and informs caveats which are applied to the PNG tenure document. The caveats identify specific issues, concerns and environmental values which the proponent should be aware of when planning development.

For some parcels, EMPR may defer posting a requested parcel to address issues. EMPR often works with other provincial agencies and the B.C. Oil and Gas Commission (OGC) to review policy and regulations to resolve specific concerns. The decision to post a parcel may also be influenced by governmental planning processes and agreements with the First Nations. Negotiations and legal challenges by First Nations may delay disposition in localized areas. As an example, approximately 26% or 790,293 hectares (ha) requested for posting in the north Montney play are presently deferred from disposition due to processes underway with First Nations.

PROPORTION OF NORTH MONTNEY POSTINGS DEFERRED FROM DISPOSITION (2009-2019)



Despite possible posting delays and the rigorous referral process described above, over the past decade, 80% of requested parcels in the Montney fairway have been disposed of on the requested sale date and more than 90% of the parcels have been disposed within two months of the requested sale date.

In Alta., there may be areas where posting requests for disposition are not accepted. Conservation areas, limited reserves, provincial parks, cities, and federal Indian lands are ineligible parcels for disposition.

TENURE SECURITY

The PNG tenure system in B.C. is designed to consider the unique aspects of PNG exploration and development in the Province. Vertical, stratigraphic rights are administered in a zone designation system which combines one or more formations together in a defined zone. A geologic zone includes a package of rock where porous and permeable strata of different geological formations directly contacting each other are grouped together. The geological zones have been carefully selected to avoid interpretation disputes and correspond to specific intervals on a reference well log.

The benefits of using the geologic zone designation system compared to issuing rights by a single geologic formation are twofold:

- There is no ambiguity between the rights holders of overlying/underlying tenure.
- A single zone designation prevents requirements for forced vertical pooling of interests by separate owners.

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PNG lease continuation in B.C. is evaluated using the legislative requirement to delimit a pool. Tenure holders in B.C. can provide geological, geophysical, and engineering data to delimit an oil or gas pool. Establishing commercial production is not required to continue tenure in a specific zone.

In Alta., a PNG lease must be proven productive at the end of its term by drilling, producing, mapping, being part of a unit agreement or by paying offset compensation.

TENURE MANAGEMENT

Tenure management in B.C. includes strong participation in the B.C. Data Catalogue to facilitate access to spatial and tenure registry data. Additionally, specific administration guides which reflect legislated requirements are available online. With a 24/7 online payment system allowing clients to submit Crown sales bids, annual rentals and associated fees, the management of tenure is simplified. Clients can also access the online title search system with complete tenure descriptions, transfer histories and encumbrances. EMPR has a client-focused approach with the disposition process and staff are available to inform and assist proponents. Additionally, EMPR works closely with several industry associations to keep informed of developing events as well as to share information on new government initiatives and policy direction.

The Alberta government has a variety of online services related to crown mineral disposition and activities. Clients can both request postings and offer bids to acquire PNG leases and licences and for oil sands permits and leases through an electronic disposition request. Administrative guides are available, and PNG continuation applications and licence validation applications can be submitted and managed electronically. Additionally, land searches are available electronically for clients to request a variety of reports that show status information of Crown surface and Crown minerals in Alberta.

The Montney resource is within a unique operating environment. The Province's commitment to reconciliation and UNDRIP ensures that First Nations livelihood and rights are considered in all resource development activities. B.C.'s pre-tenure consultation and referral process identifies potential issues that may impact the development of PNG resources, reducing associated risks and uncertainty for all stakeholders.

In localized areas, lands requested for posting may be deferred from disposition due to government planning processes, community interests and First Nations agreements, processes and legal challenges. Even so, over the past decade, the vast majority of lands in the Montney fairway have been offered for disposition within two months of the requested sale date.

2.2 PERMITTING EFFICIENCY

The permit application and review process is a key interaction between industry and government and a vital step in the early stages of a project. The B.C. Oil and Gas Commission (OGC) implemented the Application Management System (AMS) on July 11, 2016. This provided a new way of permitting oil and gas activity by incorporating both business and spatial data in the most efficient and accurate means possible. Applications could now be bundled, so that a single application may include different activity types, such as a well and a road, and for multiple wells. These changes were designed to improve efficiency and expand on the one-window approach to permitting.

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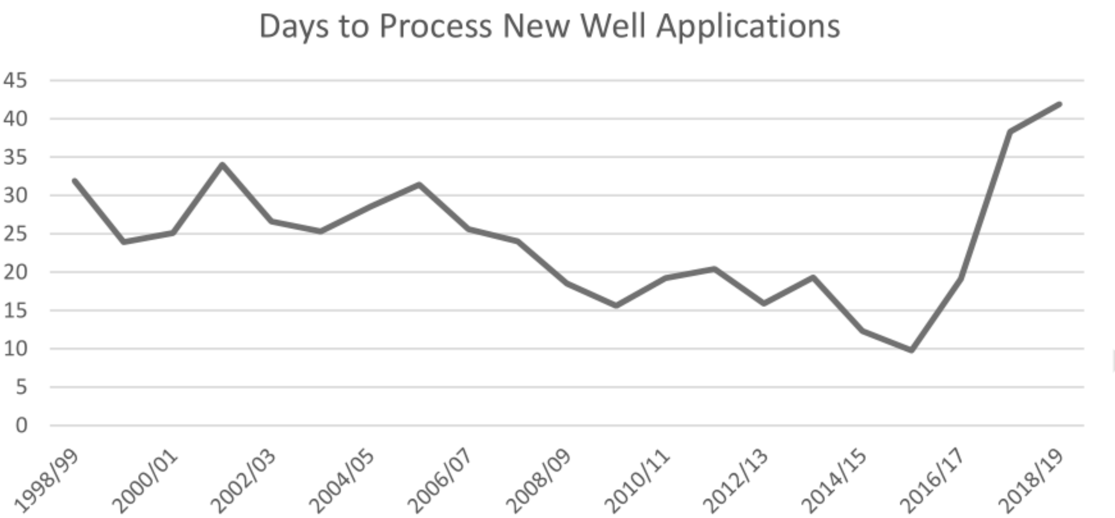
HISTORIC TRENDS IN BRITISH COLUMBIA

A licence for drilling a well is a common measure for permit efficiencies for oil and gas activity. Figure 1 below illustrates how the time to process new well applications has varied in British Columbia, controlling for bundling present in July 2016 and thereafter. Permit timelines displayed a noticeable downward trend from 2005/06 through to 2016/17. However, 2017/18 saw timelines rise steeply to approximately 40 days, up from an average of 19, even after controlling for other factors.

Figure 1: Average Days to Process New Well Applications in B.C., by Fiscal Year



Note: 2016/17 and onward controlled for bundling

Applications associated with facilities also displayed a significant increase in permit timing in 2017/18. Furthermore, well applications that also involved a road were on average an additional 66 days slower before issuing a decision, while facility applications that also included associated oil and gas activity were an average 79 days slower. Pipeline permit timing displayed no significant time trend over this period.

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COMPARISONS TO OTHER JURISDICTIONS

While the length of time needed to receive a well licence has increased in B.C., this trend is not present elsewhere. Figure 3 summarizes current permit timing for drilling permits in several competing jurisdictions. Texas currently issues drilling permits in four days, but this can be sped up to two days with an expedited process. Alberta targets a turn-around time of five days for low-risk applications, which are the majority of applications (over 95%) and is moving towards issuing drilling permits within 15 minutes with their new OneStop electronic system. Colorado, which was previously used as a benchmark by the OGC, still lists a 30-day turnaround on drilling permits while Pennsylvania is close behind at 32 days.

Figure 3: Expected Timelines for Drilling Permits in Comparable Jurisdiction

Jurisdiction	Timelines
Texas	2 days (expedited), 4 days (normal)
Alberta	5 days (low-risk), potentially 15 minutes
Colorado (historic benchmark for OGC)	30 days
Pennsylvania	32 days

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s.13 In Alberta, First Nations consultation has been delegated to the industry and is therefore undertaken before applications are submitted meaning it is not tracked in processing timelines. In B.C., First Nations consultation on oil and gas applications has not been delegated to industry and is the single determinant of aggregate timelines for applications on Crown land. Northeast B.C. is 95% Crown land whereas Alberta is 63% Crown land. Distinctions in relation to American jurisdictions are even more dramatic given that, to varying degrees, oil and gas activity in the above jurisdictions occurs on private land where oil and gas rights are held by the landowner (unlike private land in B.C. and Alberta). In those situations, regulatory applications would only come forward with agreement of the landowner simplifying the approval process.

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Packaging multiple instances of one activity type was found to be an efficient approach and was not found to significantly increase the time it takes to issue a permit. This is indeed a benefit of the OGC's new AMS electronic system.

2.3 REGULATORY EFFICIENCY

A survey undertaken in the summer of 2019 asked 161 oil and gas industry stakeholders to evaluate seven recent or proposed regulatory changes.

Respondents were asked to gauge the expected impact on key indicators of regulatory efficiency: the clarity of the requirements to get projects approved, the time it will take to obtain project approvals, and the financial costs to meet regulatory requirements. They were also asked the expected overall impact of regulatory changes as they relate to project approvals, decision process efficiency, and how they help to ensure safe and responsible energy resource management. The seven regulatory changes evaluated were:

- B.C. Spills Regulations
- Methane Emissions Reduction
- Dormancy Regulation and Comprehensive Liability Management Plan
- Jurisdictional Challenge for the Coastal GasLink Pipeline Project
- Induced Seismic Monitoring
- Professional Governance Act
- Noise Management Requirements

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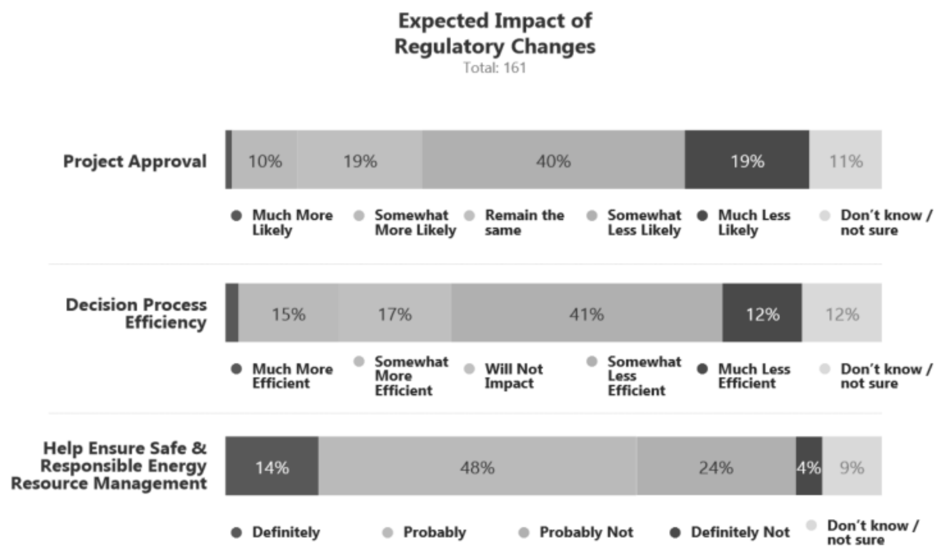

Expected Impact of Regulatory Changes
Total: 161
Project Approval
10%
19%
40%
19%
11%
Much More Likely
Somewhat More Likely
Remain the same
Somewhat Less Likely
Much Less Likely
Don't know / not sure
Decision Process Efficiency
15%
17%
41%
12%
12%
Much More Efficient
Somewhat More Efficient
Will Not Impact
Somewhat Less Efficient
Much Less Efficient
Don't know / not sure
Help Ensure Safe & Responsible Energy Resource Management
14%
48%
24%
4%
9%
Definitely
Probably
Probably Not
Definitely Not
Don't know / not sure

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Page 025 of 110

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The full survey is located in Appendix F.

2.4 DATA

Petroleum and natural gas data is collected to advance exploration and development, maximize resource recovery, regulate responsible resource extraction, and ensure environmental and social protections. Legislation in British Columbia and Alberta requires detailed PNG data collection, submission, and eventual release to the public. Generally, in Pennsylvania and Texas, detailed historical PNG data may remain private and confidential to the collecting companies, however, increasing amounts of data are now publicly available.

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In this section, well, geology, engineering, completion, production, and groundwater data are compared in four North American jurisdictions: Alta., B.C., PA, and TX. Differences in the data types required and collected, confidentiality periods, ease of data submission by industry, and public data availability are compared for the four resource prone areas. The information focuses on data available from web sites (self-service) or information that may requested directly from a regulator or government.

The applicable acts, regulations, and statutes were not compared in detail to differentiate all data collection, confidentiality, and release requirements. However, a sample of important data has been reviewed from the British Columbia Oil & Gas Commission (OGC), British Columbia Data Catalogue (DataBC), Alberta Energy Regulator (AER), Alberta Open Data (AB Open Data), Railroad Commission of Texas (RRC), and Pennsylvania Department of Environmental Protection (DEP).

DATA COLLECTION AND CONFIDENTIALITY PERIODS

PNG data are collected to advance exploration and development, maximize resource recovery, regulate responsible resource extraction, and ensure environmental protections. Legislation in Alta. and B.C. requires the submission and eventual public release of well reports and data recorded during PNG activities.

In B.C. similar to Alta., well reports and records include detailed data from:

- Comprehensive drilling and well history reports
- Unprocessed and processed log data
- Dipmeter surveys
- Directional surveys
- Drill stem test reports and analyses
- Wireline data
- Pressure-volume temperature and flow test data and analyses
- Subsurface pressure data and analyses
- Completion information
- Reports respecting monitoring of hydraulic fracturing
- Geological and geophysical information
- Drilling depths
- Casing and cementing
- Well status, gas, oil or water sample or analysis data
- Drill cuttings and cores
- Analysis and description of the drill cuttings and cores

In PA and TX, certain geologic, engineering, completion, and production data is required to be collected and submitted according to legislation. Some of this data is publicly available while other information remains confidential to the collecting company.

TYPES OF PNG DATA AVAILABLE BY SHALE GAS REGION

resource area	well records	well logs	core	completion records	production volumes	hydraulic fracturing	orphan wells	groundwater information
Alta.	✓	since 1911	✓	✓	✓	since 2013&	✓	✓
B.C.	✓	since 1948	✓	✓	✓	since 2012&	✓	✓
PA	✓	after 2016*	NA	✓	✓	since 2012&	✓	partial data
TX	✓	after 1985*	partial set@	✓	✓	since 2012&	✓	partial data

* Logs created in the normal course of business are required to be submitted after this date

@ Core is not required by State Legislation

& Hydraulic fracturing data includes composition and design

After data is submitted to a PNG regulator or governing body, it is considered confidential for a defined period. Confidentiality periods protect the information collected by a well licensee to protect the licensee's investment which maintains their advantage for discovery. After the confidentiality period has expired, the collected data becomes available to the public.s.13

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Confidentiality periods per region vary according to the original classification of the well, by prescribed confidentiality status, or by request. Generally, exploratory wells may be granted longer periods of confidentiality while data from development wells may be released to the public close to the rig release date of the well.

In B.C., well data and well reports for development wells enter the public domain two months after rig release. Discovery wells designated as exploratory wildcat are confidential for one year and a well designated as a special data well is granted 18 months of confidentiality. In Alberta, a well may be given an initial status of confidential, confidential below, or non-confidential depending on specific Lahee classification criteria. The corresponding confidentiality periods are from one month to 60 months depending on the exploratory or development nature target of the well.

In PA, certain data may be held confidential until a Right to Know Law request is received. At that point, the owner may assert that the records contain or are trade secrets and confidential proprietary information. In this case, the information may be kept confidential. In TX, by request, a company may extend the confidentiality period of certain data to 60 months.

DATA CONFIDENTIALITY PERIODS IN MONTHS

resource area	well reports	well logs	completion	production
AB	1, 12, 60+	1, 12, 60+	1, 12, 60+	confidential period + 2
B.C.	2, 12, 18&	2, 12, 18&	2, 12, 18&	confidential period + 2
PA	1	RTKL^	RTKL^	1.5, 12#
TX	12, 32	12, 36, 60%	1	1

+ Confidentiality periods correspond to the Lahee and confidential classification of the well.
& Confidentiality periods correspond to the development, exploratory outpost, exploratory wildcat, or special data classification of the well.
# Unconventional well production reports are required within 1.5 months after the production month, and conventional oil and gas well production reports are required annually.
^ Pennsylvania Right To Know Law (RTKL) protects trade secrets and confidential proprietary information.

DATA SUBMISSION

Ease and clarity of data submission is important for complete and accurate datasets. All resource areas reviewed are at different stages of implementing streamlined systems for digital data submission.

Currently, B.C. uses eSubmission as the online portal for permit holders to submit all operational data (geological, engineering, and completions) directly to the OGC. Production information is submitted through Petrinex. In Alberta, the AER's Onestop is the online tool for submission of daily tour reports, hydrocarbon emission controls, and well abandonments. The Digital Data Submission (DDS) is used for submitting well, drilling, completion, abandonment, as well as some facility, pipeline, water and environmental data. Specific geologic data is submitted directly to the AER. Production information is submitted through Petrinex. The DEP in PA requires the Oil and Gas Reporting Electronic (OGRE) system to report production/waste data, completion, reports and well logs. TX uses the RRC Online system for submitting data and reports including production reports, drilling permits, disposal/injection well monitoring information, completion reports, groundwater protection information, well status data, digital well log submissions, and notices to abandon.

PUBLIC DATA AVAILABILITY

DataBC encourages and enables the management and sharing of data across government and with the public. s.13
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The table below shows the results of a spatial data search for "oil and gas" layers and describes a sample of the types of PNG GIS datasets available by resource area.

PETROLEUM AND NATURAL GAS SPATIAL DATA

Resource area	PNG GIS datasets	Description
Alta. - Open Data & EUR**	44	basemap, wells, AER orders, scheme approvals, abandoned wells, pipelines, facility lists
B.C. - DataBC & OGC**	188	basemap, wells (surface, bottom hole, directional survey), pipelines, facilites, disposal sites, water use applications, resource exploration potential, engineering projects, pool net pay contours (by formation), geological faults, geophysical survey lines
PA - DEP Open Data Portal**	10	base map, wells (locations and type)
TX - RRC Digital Map Data**	5	base map, wells, surveys, pipelines

**Spatial data search for 'oil and gas' layers (August 2019)

In addition to spatial layers, oil and gas records, reports, measurements, well logs, completion intervals, and production volumes are made available in different formats, from scanned documents to very large digital datasets. Each resource area varies in the amount and types of data available. In general, the data sets in Alta. and B.C. contain data fields from many disciplines (geology, reservoir engineering, completions, production, etc.) while the datasets in PA and TX may offer less detail.

The types of production data recorded and publicly available differs in each resource area. Oil, gas, water and injected volumes per wellbore are reported and publicly available in all resource areas. s.13
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s.13 . In B.C, field condensate volumes are public, while condensate produced at the plant is kept confidential to the producing company. The OGC anticipates changes in the fall of 2019 to make the condensate plant data (previous B.C.-08 information) available to the public. s.13
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PNG DATA AVAILABLITY

resource area	well reports	well logs	core	production

Alberta	full dataset including drilling, geology, test, perforation, completion	digital logs (Raster, TIFF, LAS 1993-current)	AB Core Research Centre (1.55 million boxes of core, 20 million vials of drill cuttings)	production and injection activity by month (1962-current) ***Condensate volumes absent or inconsistently reported***
B.C.	full dataset including drilling, geology, test, perforation, completion	digital logs (TIFF, pdf, LAS 2014-current) historical logs by request	B.C. Core Research Facility (6400 wells with core, 30,000 wells with drill cuttings,)	production and injection activity by month (1954-current) ***Condensate volumes absent or inconsistently reported***
PA	spud information, oil and gas formations	database subscription basis	unknown	dataset from 1980-current
TX	drilling permit information 1976-current	digital logs (TIFF) after 2004, paper well logs at University of Texas	Austin Core Research Center (700, 000 boxes core and cuttings from TX, US, worldwide)	dataset from 1993-current

Generally, in PA and TX, detailed historical PNG data may remain private and confidential to the collecting companies. However, in PA and TX increasing amounts of data are now digital and publicly available.

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Page 031 of 110

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3. CLIMATE POLICY

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3.1 METHANE REGULATIONS

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Methane is the main component of the natural gas used to heat homes and power factories. It is also a potent greenhouse gas responsible for approximately 25 percent of the human-caused global warming today. Methane is 70 times more potent as a greenhouse gas than carbon dioxide over a 20-year period after it is released.

Canada is the first country in the world to tackle methane emissions from upstream oil and gas sector with a federal policy. On April 26, 2018, the federal government released its *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* for reducing methane emissions by 40 to 45% from the oil and gas sector.

In 2018, British Columbia finalized regulation 286/2018 to amend the *Drilling and Production Regulation,* which is the methane emissions regulation under the *Oil and Gas Activities Act*, which aims to reduce methane emissions by 45% by 2025, relative to 2014 levels.

The regulatory approach considers B.C.'s specific industry makeup including economics and costs, competitiveness as well as policy and legislative implications. The provincial methane regulations, as well as those developed by federal government, introduce control measures to reduce fugitive (unintentional) and venting (intentional) emissions of methane from B.C.'s upstream oil and gas sector.

Provincial regulations will require specific industry compliance action starting in 2020 and will be fully implemented in 2023. Under the *Canadian Environmental Protection Act*, provinces have the flexibility to design a program for their jurisdiction and seek equivalency with federal government requirements. The equivalency negotiation is ongoing between federal and provincial government. Once the process is concluded the federal methane regulation would be stood down and only the provincial methane regulations would apply in British Columbia.

Unlike Canada, the U.S. Environmental Protection Agency finalized rules that regulate methane emissions from oil and gas industry in 2016. Under the Trump administration, federal agencies have moved to roll back regulations. In 2018, the EPA proposed changes to methane regulations, seeking to reduce the frequency for monitoring methane leaks and increase the time allowed for their repair. The proposed rule would also allow companies to meet certain state requirements for leaks as an alternative to EPA standards, finding that state regulations such as Texas "are at least equivalent" to the EPA's leak requirements.

Texas follows an EPA rule that only applies to new, reconstructed and modified oil and gas facilities and excludes existing facilities. Federal rules would monitor compressors four times per year and monitor wells twice per year for fugitive emissions. The proposed rules will revise the monitoring requirements to twice per year (semi-annual) at compressors, and once per year at wells. The B.C. methane regulation requires monitoring three times per year for compressor station, gas plants and multi-well batteries and once per year for single well batteries, tight/shale wells and at treating/disposal/injection facilities.

Pennsylvania is the nation's second largest gas-producing state after Texas. The recently finalized methane regulation sets limits on smog forming volatile organic compounds (VOCs) from existing natural gas facilities. With methane reduction listed as a "co-benefit," the rule doesn't directly establish specific emissions standards for methane.

Overall, B.C. is not only Canada's second largest natural gas production province but also a leader in environmental regulatory and policy among the major natural gas production jurisdictions, especially concerning methane (Table 1).

Based on the Environment and Climate Change Canada's (ECCC) regulatory impact analysis statement, the B.C. regulation results in cumulative emission reductions of 3.1 Mt of methane (in CO_2e) from January 1, 2020 to January 1, 2025, which exceeds the federal regulations' 2.77 Mt. The B.C. regulation achieves greater emission reductions than the federal regulations due to the increased stringency for new facilities and early implementation dates for some standards.

Table 1 - Methane regulations in different jurisdictions (natural gas producing provinces and states)

	Natural gas produced (Tcf, 2017)	**Description of provincial / state methane regulations**	**Description of federal methane regulations**
British Columbia	1.64	Comprehensive provincial level methane regulation in place.	Comprehensive federal methane regulation in place.
Alberta	3.83	The AER methane regulation in place.	Comprehensive federal methane regulation in place.
Texas	6.3	No comprehensive state level methane regulation in place.	EPA methane regulation and Bureau of Land Management (BLM) methane regulation 2016.
Pennsylvania	5.39	(1) two general permits for new sources and compressor stations, and (2) a regulatory package that will apply to new and existing sources.	EPA methane regulations and BLM methane regulation 2016.

COMPLIANCE COST FOR METHANE REGULATION

Based on the regulatory impact analysis statement of the federal methane regulation (Canada Gazette Part II, 2019). The compliance costs associated with the regulations will vary by region. Considering the National Energy

Board (NEB) forecasting of natural gas production data, the costs for Western Canadian Sedimentary Basin (WSCB) provinces are summarized in Table 2.

Table 2 The cost associated federal methane regulations on WCSB in 2020

	B.C.	Alta.	Sask.
Natural gas production in 2020 (bcf)	1,916	3,763	131
Methane regulation compliance cost distribution across the provinces (%)	9	57	33
Estimated methane regulation costs (million $)	27	172	101
Estimated methane regulation costs per unit volume of natural gas in 2020 ($/mscf)	0.014	0.046	0.769

The estimated federal methane regulation compliance costs for B.C. natural gas is $0.014/mscf, the lowest among jurisdictions in the WCSB. Furthermore, B.C. methane regulations are designed with the specific characteristics of the B.C. oil and gas industry in mind, to achieve reductions at the lowest cost possible. The B.C. regulation costs are estimated to be 30% lower than the federal regulations while ensuring equivalent environmental outcomes. This is primarily driven by the nature of the hydrocarbons produced in the Province. The development of Albertan and Saskatchewan resources are focused on the extraction of oil, while B.C. development is focused on natural gas. Production practices for natural gas when compared to those of oil have far fewer opportunities to reduce the amount of fugitive methane emissions.

According to the industry submission to the Ministers 2018 joint working group report, there are estimated to be costs of $150 million/year to liquid rich natural gas sector, assuming the drafted Alberta methane regulation is implemented in WCSB (incremental cost to U.S. jurisdictions with modest methane regulations – including Texas). The incremental cost equates to three cents/mcf incremental to U.S. (Texas) on produced volumes as of 2020.

Although B.C. methane regulation has slightly higher cost than U.S. jurisdictions (Texas, Pennsylvania), it still lower than the federal rules and other provinces in WCSB.

B.C. ACTIONS ON METHANE REDUCTIONS

To encourage the oil and gas industry to take early action on methane reductions, the Province set up a key incentive program for this sector called the Clean Growth Infrastructure Royalty Program (CGIRP). This provides up to 50 percent of eligible project costs in royalty deductions. The CGIRP offers an incentive for B.C.'s natural gas producers and/or pipeline companies in partnership with producers, to invest in clean technologies that will result in reduced methane and other greenhouse gas (GHG) emissions. Eligible CGIRP projects in 2019 include electrification of oil and gas equipment, facilities and infrastructure projects that reduce venting/combustion emissions, helping achieve the legislated Province's methane and GHG reduction goals and demonstrate further sustainable management in the oil and gas sector. The 17 approved projects from the previous program are expected to cumulatively reduce one million tonnes CO_2e by 2025.

To support ongoing progress on meeting targets, the Oil and Gas Commission (OGC) is involved in the British Columbia Methane Research Collaborative (MERC), which was created to focus research efforts toward managing and reducing the release of methane from oil and gas operations. The initiative involving provincial agencies, environmental, scientific and industry groups will identify the knowledge gaps, make recommendations on the design and implementation of the key research deliverables critical to the identification, quantification and control of methane emissions to meet reduction goals. It provides an effective platform for industry and government to work collaboratively to fill knowledge gaps in methane emissions data, improve the accuracy of the emissions baseline and test the effectiveness of new technology. The results will lead to optimized regulatory stringency, inform and support the update of provincial policies and regulations to meet current and future methane emission reduction goals.

3.2 EMISSIONS INTENSITY

Emission intensity of B.C. natural gas production is low compared with other fields for LNG projects around the world.s.13

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The amount of GHG's emitted per unit of output during the natural gas production is known as GHG emission intensity. The emission intensity of B.C. Montney is low compared with the other fields for LNG projects all over the world. This section summarizes reports and studies on GHG emission intensity and offers a comparison between B.C. and other jurisdictions.

GHG INTENSITY STUDY – JOULE BERGERSON, UNIVERSITY OF CALGARY

The study estimates the upstream GHG emissions intensity from 10 natural gas fields in six different countries for current and potential LNG projects.

The GHG emissions intensity covers upstream activities including exploration, drilling and development, production and processing of natural gas produced from each field. In 2014 close to 90% of methane emissions from the oil and gas sector originated from upstream activities. The Oil Production Greenhouse Gas Emissions Estimator tool (OPGEE V2.0b, Stanford University) is used for estimation and the results are presented in a carbon dioxide equivalent (CO_2e) emissions per MJ of processed natural gas. The results shows that the emission intensity of B.C. Montney is low when compared with other fields all over the world (Figure 1).

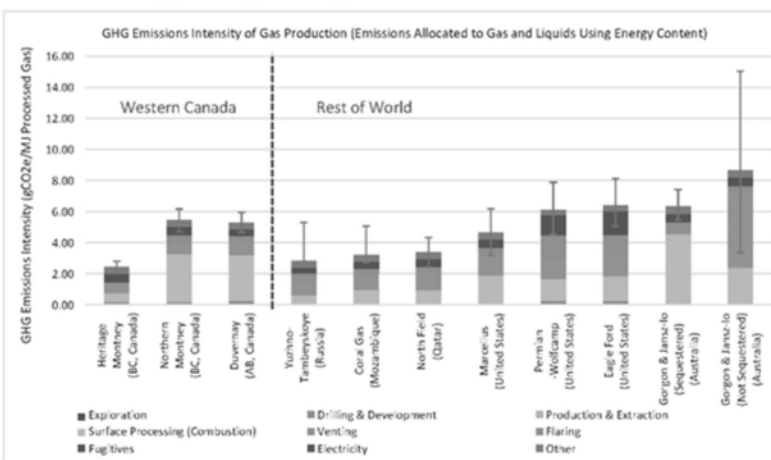

Figure 1 Base case GHG emission intensity of natural gas production and processing

JOHNS HOPKINS UNIVERSITY ASSESSMENT OF B.C. LNG AND OTHER REPORTS

According to the IEA Gas Market Report 2019, natural gas dominated 2018's global energy growth, accounting for 45% of total demand growth, more than any other fuel. Natural gas helped to reduce air pollution and limit the rise of energy-related CO_2 emissions by displacing coal and oil in power generation, heating and industrial uses.

The Asia-Pacific market represents 75% of global liquefied natural gas (LNG) imports. China is set to surpass Japan as the world's biggest natural gas importer this year. The Chinese government has been striving to switch away from coal-based power generation and toward cleaner fuels like natural gas because of air quality concerns, resulting in the country's gas consumption rising by one-third over the past two years.

To determine the net impact of LNG on global greenhouse gas emission, researchers at Johns Hopkins University recently conducted a detailed analysis of life-cycle of GHGs specific to LNG produced in B.C. and shipped from Kitimat to Asia for electricity generation (Kasumu et al., 2018). The study assessed the five largest LNG importing countries in Asia, namely; China, India, Japan, Taiwan and South Korea. Overall, the results suggest that there is a net environmental benefit in terms of greenhouse gas emissions reduction when importing Canadian natural gas for electricity generation in the five countries considered, except for the case of Japan prior to the Fukushima nuclear disaster.

Coleman et al. (2015) compared life cycle emissions from Canadian LNG and weighted average life cycle emissions by the power sector in the 13 major import markets. As shown in Figure 2, the results indicate that exporting LNG to China, India, Japan, and Taiwan would lower global GHG emissions because those countries rely so much on power from coal and oil. Exporting LNG to the other major potential markets, however, would increase net GHG emissions because those countries rely on low-GHG sources for a significant portion of their power needs.

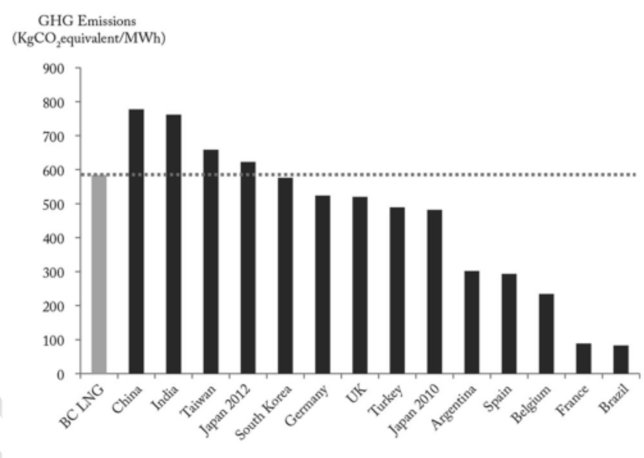

Figure 2 Life cycle greenhouse gas emissions from electricity generation in major, potential markets for Canadian LNG (source: Coleman et al, 2015)

Gas-fired power plants produce much lower carbon dioxide emissions than coal-fired plants for the electricity generation. The methane leakage (the percentage of methane produced is emitted to the atmosphere from well head to consumer) may cut that advantage and could even wipe it out altogether. In the ongoing debate about the climate benefits of fuel switching from coal to natural gas for power generation, many literature reports were focused on this topic.

Tanaka et al. (2019) examined global scenarios for transitioning from coal to gas using multiple metrics developed for climate impact assessments from a variety of direct and indirect emissions of such a shift on both shorter and longer timescales ranging from a few decades to a century. Focusing specifically on the world's leading power generators; China, Germany, India, and the U.S. The study combined multiple metrics to address both short and long-term climate impacts in parallel. It was found that natural gas power plants have a smaller impact in both the short and long-term when compared with coal power plants, even when considering the high potential for methane leakage For China, natural gas power plants emit less than coal plants under all methane leakage scenarios (up to 9%).

Other studies were conducted for evaluating net GHG emission reductions when switching from coal to shale gas in China. The results indicated that the breakeven methane leakage rates to be approximately 6.0%, 7.7%, and 4.2% in the power, residential, and industrial sectors, respectively, under GWP20 (Qin et al., 2017). Similarly, Gilbert and Sovacool (2018) found that the Chinese LNG imports reduce emissions relative to coal under all leakage scenarios (0-6%).

Farquharson et al. (2017) evaluated the life cycle greenhouse gas emissions of coal and natural gas used in new, advanced power plants using a broad set of available climate metrics to test for the robustness of results. Climate metrics such as global warming potential, global temperature change potential, technology warming potential, and cumulative radiative forcing are used for the climate-change model to validate the results. The results show that all climate metrics suggest a natural gas combined cycle plant offers lifecycle climate benefits over 100 years, compared to a pulverized coal plant, even if the lifecycle methane leakage rate for natural gas reaches 5%. Over shorter time frames (i.e., 20 years), plants using natural gas with a 4% leakage rate have similar climate impacts as those using coal but are no worse than coal.

The International Energy Agency (IEA) reported that an average global methane leakage rate is 1.7%. This represents the average percentage of gas produced that is lost to the atmosphere before it reaches the consumer (Gould and McGlade, 2017). A recent study published in Science magazine estimates that the average methane leakage rate of U.S. natural gas industry is 2.3% of total production (Alvarez et al., 2018). In an early study, Alvarez et al. (2012) found that new natural gas power plants produce net climate benefits relative to efficient, new coal plants using low gassy coal on all time frames as long as leakage in the natural gas system is less than 3.2% from well through to delivery at a power plant.

With more stringent methane regulations, and other policies, proven technologies and practices in place, the natural gas producers in B.C. have much smaller leakage rate. Based on GHG reporting data, B.C. methane emission leakage rates are around 0.22% (CAS personal communication, 2019). The lower values than other jurisdictions are due to several reasons, including widely employing electrification of upstream operations and greater use of non-emitting devices at well sites.s.13

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The results indicate that B.C.'s natural gas has much lower upstream emission intensity and smaller methane leakage rate. This combined with shorter shipping distance to potential Asian markets that are shifting from coal to natural gas (versus the U.S. Gulf LNG) will provide a significant net reduction in global greenhouse gas emissions.

3.3 ASSESSMENT OF WATER COSTS ASSOCIATED WITH NORTHERN B.C. GAS DEVELOPMENT WELLS

Natural gas exploration and development in northeast B.C. requires large volumes of water. The largest proportion of water use is during well completions, with the majority used in hydraulic fracturing operations. Water handling during completions is regarded within well completions costs, and includes costs relating to sourcing, using and disposing of water.

On average, B.C. uses less water per well, and has a lower average well and water cost range compared to U.S oil and gas basins. EIA (2016) reported that in 2015, 12% of U.S. onshore oil and natural gas drilling and completion costs were associated with completion fluids and flow-back costs, including sourcing and disposal of water and other materials. Across the U.S. onshore oil and gas market, these costs range from $0.3 MM to $1.2 MM making up 5% to 19% of the total well cost.

Basin	Costs water (USD)/well	Average Well Cost ($ million USD)	Ave vol water (m3)/well
B.C.	0.30-0.59 million (11%*) 0.51-1.02 million (19%*)	2.7 – 5.3	12,000 - 18,000
Bakken	0.86 million (11%)	7.5 - 8.1	13,138 - 19,866
Eagle Ford	0.98 million (13%)	6.9 - 7.6	26,776 – 31,140
Marcellus	0.96 million (15%)	4.9 - 7.9	16, 820 – 31,140
Permian	1.43 million (19%)	6.6 - 7.9	28,413 - 39,732

Source: FracFocus B.C. and EIA (2016)

**estimated cost calculated from low to high U.S. market percentages*

Water Sourcing

Water sourcing costs are a function of regional conditions relating to surface access, aquifer resources and climate conditions. In B.C., water for oil and gas activities is managed by B.C. Oil and Gas Commission (OGC). The volume of available water for oil and gas activities in B.C. currently exceeds demand.

The percentage of short-term water authorizations issued to oil and gas companies decreased from 2013 to 2015, and water sourced from produced water and private agreements increased in the same period (OGC Annual Water Reports, 2013-2015). Fifteen percent of water authorizations allowed for flowback water[1] use, and this did not vary from 2013 to 2015.

A case study completed by Black Swan Energy Ltd. (Marcil, 2017) reported costs in water acquisition were cheapest when pumping from freshwater source or freshwater pit, and most expensive when trucking from private source.

Water Transportation and Use

Water transportation options include trucking or pumping from source through pipeline or temporary hose lines to the drilling site. Transportation options are limited by existing infrastructure, distance between wells, water source and disposal location. Transportation costs of water have been identified as the largest cost relating to water handling in the U.S., with approximately 46% of the water market volume attributed to water hauling in 2015 (SourceWater Inc., 2018).

Average reported water volumes used during completions in B.C. is between 12,000 and 18,000 m^3 per well (FracFocus B.C., 2019). New and active pipeline infrastructure registered in B.C. from 2000 to 2018 (OGC Pipeline Project Details) has seen an increase in the network of pipelines with water capacity, indicating a shift to investment in longer-term water infrastructure.

Treatment and Disposal Costs

[1] Flowback water is water that has been allowed to flow from the well.

Water disposal is normally done by re-injection, evaporation from disposal tanks, recycling or removal by truck or pipeline. Water disposal in B.C. is regulated under the *Oil and Gas Activities Act* (2016) and *Environmental Management Act* (2003). OGC also monitors water disposal relating to B.C. oil and gas activities.

B.C. OGC data (OGC Water Gas Disposal Data, 2019) shows the reported total volume of water disposed of is increasing over time despite the number of well completions decreasing since 2007. As such, the average volume of water disposed of per well is increasing. Water disposal costs have been identified as the second largest cost behind transportation in the U.S.[2], with approximately 17% of the water market volume attributed to water disposal in 2015 (SourceWater Inc., 2018).

Water hubs are permitted through B.C. OGC and allow companies to store produced water either in a pit, pond, or in tanks for recycling, reuse and disposal. The total permitted capacity for B.C. water hubs exceeds one million m3, with 90% allocated to open pits and/or pond storage.

A case study completed by Black Swan Energy Ltd. in 2017 (Marcil, 2017) identified trucking costs from water source to well varied depending on the water source type and location. Trucking water to disposal incurs higher costs and include additional disposal fees.

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3.4 ENVIRONMENTAL, SOCIAL AND GOVERNANCE (ESG)

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Under the CleanBC strategy, B.C. has an objective to develop a sustainable, cleaner, and more energy efficient province. Natural gas fits into this vision as a low-carbon fuel option over heavier petroleum products. In comparison to other options, natural gas use results in lower levels of greenhouse gas and air pollution. Domestic natural gas consumption is at 11% [3][Mou] of total Provincial production. Options for market expansion in B.C. and North America are limited (as stated in section 2.2). Instead, the sector is seeking to expand markets overseas.

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[2] Transportation of water is the largest reported cost, reported at approximately 46% of market volume.
[3] Calculated from the three-year average of: 2016 (10.69%) 2017 (11.88%), and 2018 (10.44%).

Page 040 of 110

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Figure A2. Canada's ranking on the Environmental Performance Index compared to other natural gas producing jurisdictions

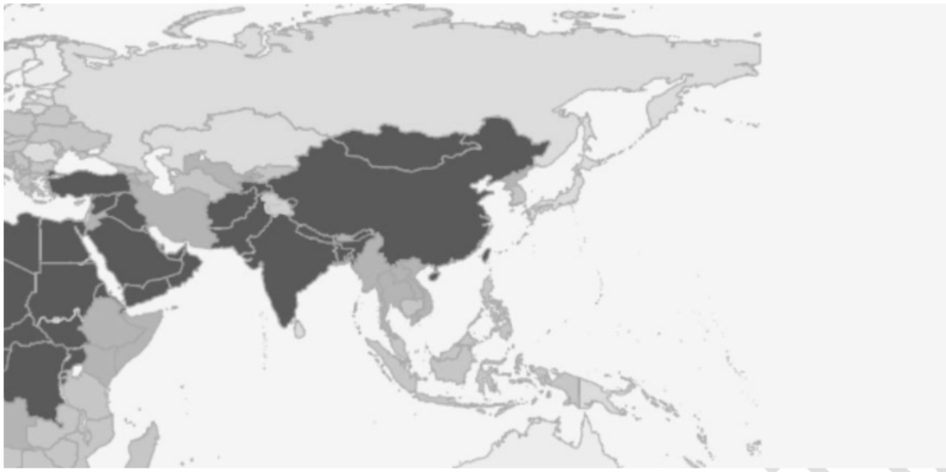
Country	Rank
Norway	14
Australia	21
Canada	25
United States of America	27
Qatar	32
Russia	52
Azerbaijan	59
U.A.E.	77
Saudi Arabia	86

Source: YCELP, Environmental Performance Index: 2018 EPI Results

Choosing Natural Gas Over High-Carbon Fuels

Potential export markets for B.C.'s natural gas are also turning their attention to the environmental qualities of B.C.'s natural gas. Sourcing from B.C. helps meet a need for economically sourced, low-polluting fuel used in power generation and heating. Ambient air quality is an issue in many parts of the globe, especially in regions of Africa and Asia. Figure B1 shows a map of ambient air pollution for Asian consumer market areas where there is the potential to improve conditions by increasing the use of natural gas over other combustibles.

Figure B1. Map of Ambient Air Pollution with annual mean concentrations of fine particulate matter (PM2.5) in urban areas (μg/m^3) – Asia

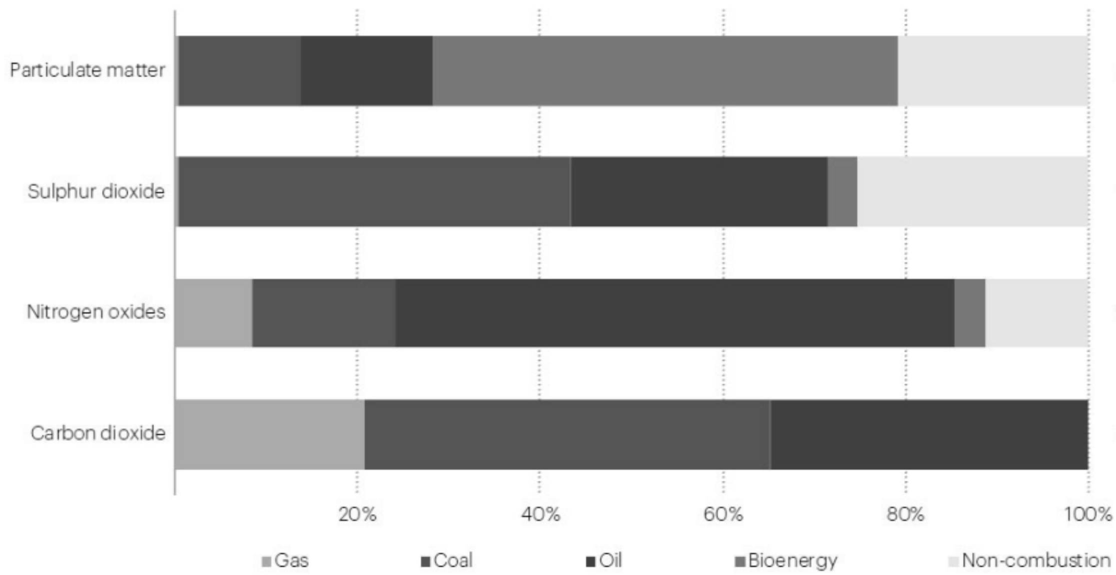


Annual concentration levels of fine suspended particles of less than 2.5 microns in diameters, where the darker shading shows levels to be at 35% or higher. The WHO guidelines set the maximum safe level of annual average concentration to 10 μg/m^3. The WHO has set a series of interim targets of with the maximum set at 35 μg/m^3 for cities. However, many cities have pollution levels that well exceed this level (WHO, Health Topics). Map sourced from World Health Organization, Global Health Observatory (GHO) data.

Many regions around the globe now have a mandate to switch away from coal, oil and other high-pollution combustible fuels that are causing poor air quality issues [IEA; WHO, 2018]. The main air pollutants from combustible fuels causing poor ambient air quality are: particulate matter (of varying sizes), sulphur oxides (mainly SO_2) and nitrogen oxides (NO_x).

Research into air quality continues to show that it affects human health in very profound ways. Statistics compiled by the World Health Organization show that in 2016, 4.2 million people died from health issues directly linked to ambient air pollution [WHO, 2018]. Other analysis by the International Energy Agency (IEA) states that in 2015, 2.9 million people died prematurely due to poor outdoor air quality, with the majority of these deaths occurring in Asian countries (China 31%, India 18%, Southeast Asia 6% and other developing Asian countries 7%) [IEA, p.34]. Air pollution-related health issues and deaths are lowered when air quality improves.

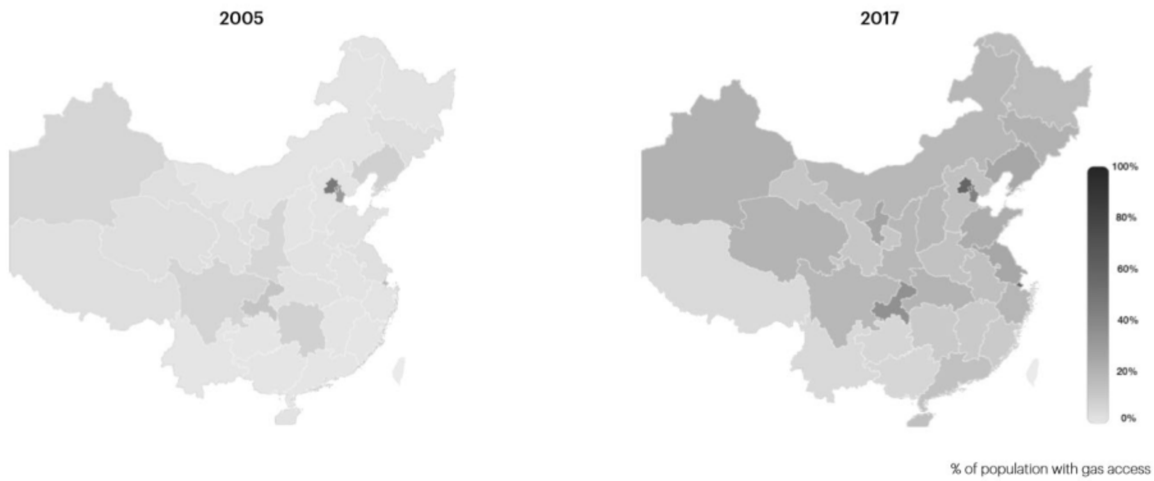
Figure B2. Share of gas in total energy-related emissions of selected air pollutants (2015) and CO_2 (2018)



Non-combustion emissions originate from industrial processes and transportation (non-exhaust). Original data sourced from International Institute for Applied Systems Analysis (IIASA), graph sourced from IEA, page 33.

The use of natural gas over other fuel sources results in less particulate matter, and almost no sulphur oxides and nitrogen oxides emissions [see figure B2]. Even when considered only as a bridging fuel, natural gas offers significant value in improving air quality from power generation and heating activities. Figure B3 shows how in China, grave air quality concerns have resulted in the expansion of access to natural gas for domestic and industrial use. Between 2005 and 2016, access to natural gas increased fivefold, equalling connections for approximately 27 million households. Since 2016 this number has continued to grow. With the increased use of natural gas and other alternatives to coal, air pollution concentration peaks have lowered, however, overall air quality is still above the country's set standards and China is continuing to pursue its clean air policies as a result.

Figure B3. Access to natural gas in China has greatly increased in recent years



A comparison of percentage of population with access to natural gas, 2005 versus 2017, where darker shading represents a higher percentage of the population with access. Maps are may not accurately depict international frontiers and boundaries. Original data sourced from the National Bureau of Statistics of China, maps sourced from IEA, page 75.

Meeting climate change commitments

Consumer markets are also starting to show an interest in how natural gas sourced from B.C. can have a role in helping them meet their climate change commitments. 185 of 197 countries have ratified the Paris Agreement hence making a public commitment to reduce the causes and impacts of climate change at the national level under the United Nations Framework Convention on Climate Change (UNFCCC) [United Nations, Climate Change]. This includes all of East, South, and Southeast Asia countries [United Nations, Treaty Collection] – the potential markets for B.C.'s LNG. Figure C1 summarizes some of these national commitments.

The interest in B.C.-sourced natural gas is also seen in commentary from environmental assessment rationale, such as that for the new Tacoma LNG facility in Washington State which explicitly requires that supply be sourced exclusively from B.C. and Alberta (in effect, the Montney Formation) [Ecology and Environment, Inc]. The section on Emission Intensity (5.2) examines how B.C.'s Montney Formation compares to other natural gas jurisdictions in terms of GHG emissions intensity.

Figure C1. Asian Countries GHG Reduction Commitments

Asian Country	Paris Agreement Pledge & Targets	Other targets of note
China	-To reach peak CO_2 emission levels at the latest by 2030 -Decrease carbon intensity of GDP by 60% to 65% below 2005 level by 2030	-Increase natural gas in the total primary energy supply mix to around 10% by 2020*
Japan	- To reduce CO_2 emission by 26% below 2013 levels by 2030	
South Korea	-To reduce CO_2 emission by 37% below the business as usual level by 2030	
India	- Decrease carbon intensity of GDP by 33% to 35% below 2005 level by 2030	-In 2007, the then prime minister committed to never having the

		emissions per capita value for India exceed that of developed nations

**Supported by increase in higher population with access to natural gas, shown in Figure B3*

Information sourced from data provided by Climate Action Tracker (2019)

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4. MARKET ACCESS

Within the last decade natural gas development has drastically changed. Enhanced technology which has changed the natural gas supply, altering; infrastructure capacity, key demand markets, and natural gas pricing are all having an impact on producer economics and resetting the market place.

4.1 COMPARISON OF TRANSPORTATION COST TO NORTH AMERICAN HUBS

Moving B.C.'s natural gas to market has associated toll costs. For this report, natural gas market prices and associated tolling costs to deliver to the market were gathered and evaluated. The markets with the least cost transportation tolls are the Alberta NGTL market and Huntingdon/Sumas market. This is due to the market's geographical proximity to B.C.'s supply.

This, however, is not the case for realizing the highest netback price for the natural gas. Currently, more distant market hubs such as the Chicago hub or Dawn Hub in Ontario net back a higher price due to stronger hub prices.

Western Canadian supply can compete with the Marcellus gas on a toll cost basis on the Dawn (southwestern Ontario) and Chicago markets however the pipeline capacity to reach those markets has been fully reached.

A company's consideration when producing natural gas is the costs associated with getting their product to market, and the infrastructure capacity available to get to the desired markets. High priced markets are more desirable; however, in Canada they are situated in the east. The markets that are conveniently closer to B.C. have a lower associated price. The realized price for natural gas is a netback from an end market price less the associated tolls to the B.C. plant outlet.

Alberta has a slight tolling advantage to B.C. in selling gas on the Alberta system and eastern markets because it is geographically closer. However, this is true for the B.C. markets for Station 2 (near Chetwynd, B.C.) and Huntingdon (Abbotsford, B.C.) hubs.

The lowest cost transportation tolls for moving B.C. natural gas to a market are the Alberta NGTL market at Cdn$0.56/Gj and Huntingdon at Cdn$0.60/Gj, due to their proximity. However, the price for natural gas is lower in these markets.

However, B.C. can be competitive in the east even when including tolling costs. The Chicago market has a competitive toll of Cdn$0.77/Gj, a market for liquids and a strong Chicago hub price compared to closer to home. This allows B.C. to be competitive with Marcellus gas; however, pipeline capacity is currently full.

Looking at the 3-year forward price curves for various natural gas hubs[4], the highest netback market for B.C. production is currently Chicago via the Alliance Pipeline, with a net back price of Cdn$2.76/Gj. The second highest is the Dawn Hub price via the Alliance Pipeline, and the third highest is the Vector pipeline at Cdn$2.63/Gj. The fourth highest net back price is moving gas to our local hub, Huntingdon, at Cdn$2.30/Gj.

Huntingdon is a higher priced hub than AECO because the pipeline capacity to Huntingdon is full and demand can exceed the ability to provide supply to this market. Enbridge recently just had the Canadian Energy Regulator approve an expansion to the pipe to Huntingdon that will improve reliability and capacity with new higher efficient horsepower compressors.

The lowest two netback prices are related to moving natural gas to the closest Alberta NGTL hub with a netback price of $1.70/Gj and $1.89/Gj depending on the pipeline path you choose to get there. AECO is the other lowest priced natural gas market hub in North America, thanks to the huge supply from the Montney play which has grown within a limited demand market.s.13

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Pipeline routings to market, pricing and Net backs

Hub	Price Cdn/Gj	Source to Market Transport Cost / G	Volume Lost To Fuel	Net Back Before Fuel	Net Back After Fuel	Capacity Status
Dawn Market	Dawn forward Price (3yr)					
From B.C. via Alliance to Chicago Vector to Dawn	$ 3.83	$ 1.04	5.4%	$ 2.78	$ 2.63	No capacity
From B.C. via Alberta, Transcanada Mainline to Dawn (LTFP)	$ 3.83	$ 1.33	7.3%	$ 2.50	$ 2.31	One time no capacity 10yr term
From B.C. via Alberta, Transcanada Mainline to Dawn (SWDA)	$ 3.83	$ 2.14	7.3%	$ 1.69	$ 1.56	Limited IT capacity
From B.C. via Alberta, Transcanada to Dawn (North Bay Junction LTFF	$ 3.83	$ 1.49	7.3%	$ 2.34	$ 2.17	No capacity 10yr term
Average B.C. net back					**$ 2.17**	
From Alberta via Alliance Chicago Vector to Dawn	$ 3.83	$ 0.89	4.6%	$ 2.94	$ 2.80	No capacity
From Alberta, Transcanada Mainline to Dawn (LTFP)	$ 3.83	$ 1.14	6.7%	$ 2.69	$ 2.51	No capacity 10yr term
From Alberta, Transcanada Mainline to Dawn (SWDA)	$ 3.83	$ 1.95	6.7%	$ 1.88	$ 1.75	Limited IT Capacity
From Alberta, Transcanada to Dawn (North Bay Junction LTFP)	$ 3.83	$ 1.30	6.7%	$ 2.53	$ 2.36	No capacity 10yr term
Marcellus to Dawn via Rover/Vector	$ 3.83	$ 1.34	1.8%	$ 2.49	$ 2.45	Capacity Available plus Nexus Line coming
Chicago Market	Chicago Price (3yr)					
B.C. to Chicago via Alliance Pipeline	$ 3.68	$ 0.77	5.2%	$ 2.92	**$ 2.76**	No capacity
Alberta to Chicago via Alliance Pipeline	$ 3.68	$ 0.62	4.3%	$ 3.07	$ 2.94	No capacity
Marcellus to Chicago via Rover/Vector	$ 3.68	$ 1.16	1.60%	$ 2.52	$ 2.48	Capacity available
Alberta Market (Aeco)	Aeco Price (3yr)					
B.C. to Alberta via Enbridge NGTL	$ 2.30	$ 0.56	2.4%	$ 1.74	**$ 1.70**	Capacity expansions coming
Alberta via NGTL	$ 2.30	$ 0.37	1.8%	$ 1.93	$ 1.89	Capacity expansions coming
Pacific NorthWest (Huntingdon)	Huntingdon Price (3yr)					
B.C. via Enbridge to Huntingdon Border	$ 3.02	0.60	4.9%	$ 2.42	**$ 2.30**	No capacity
Alberta via Huntingdon via NGTL and Enbridge	$ 3.02	$ 0.97	6.7%	$ 2.05	$ 1.91	No capacity
	Japan 2020 price					
B.C. netback LNG	$ 8.59	$ 5.66	2%	$ 2.93	**$ 2.87**	

Because B.C. natural gas has further to travel to reach higher priced markets, there are associated tolling charges which net back a lower realized cost. Closer markets have lower tolling costs associated but the market prices for natural gas are lower.

[4] Three year forward price curve from June 2019 Sproule forecast.

In order to increase market prices there needs to be an increased infrastructure capacity, expansion to new markets or a reduction in natural gas production across North America.

4.2 MARKET ACCESS: A CLOSER LOOK

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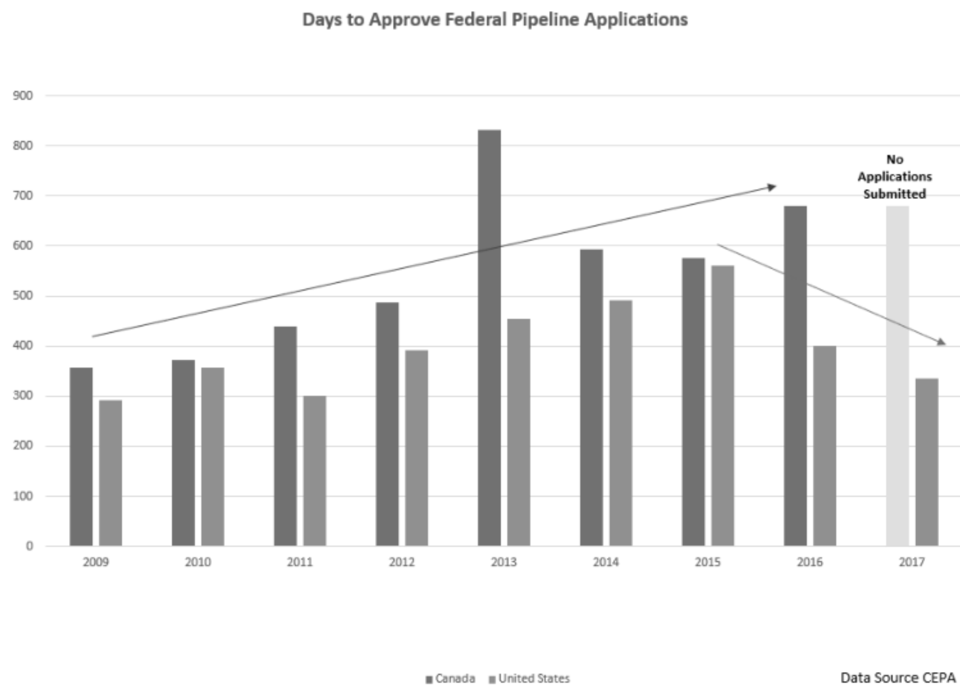
Chart 1

[5] Regulatory competitiveness in Canada's pipeline industry



PIPELINE CAPACITY

B.C. and Alberta have been able to maintain and gain market share on the TransCanada mainline system accessing the Dawn hub thanks to a TransCanada's Dawn Long-Term Fixed Price service offering, where 23 shippers were able to transport 1.5 PJ/d from Empress to Dawn for a ten-year term, at a fixed price of $0.77/GJ[6]. The traditional transportation service is more than double the price of moving gas to Dawn.

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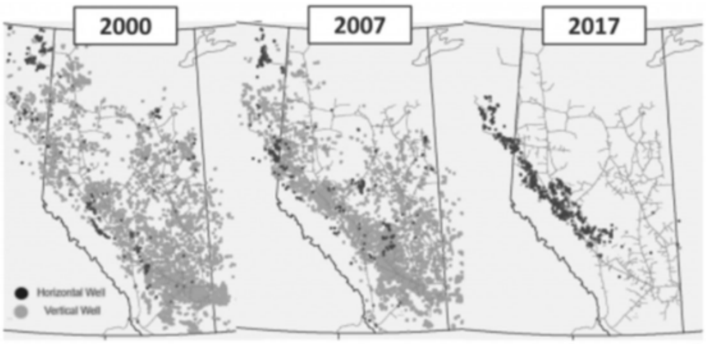
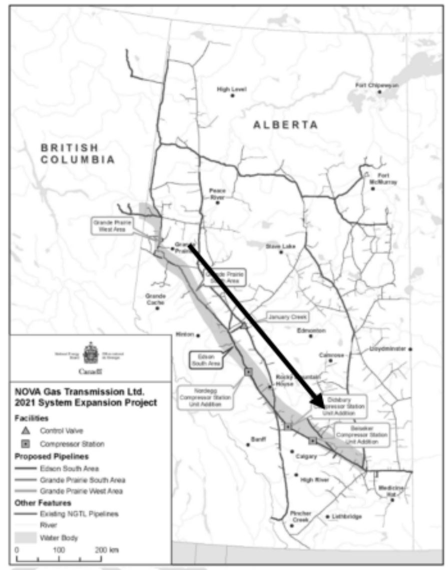
Natural gas production for western Canadian natural gas supply shifted to the northwest portion of the Alberta and northeast B.C. (Montney Basin). Below is a map showing how unconventional development has become more concentrated on the western side of Alberta and northeast B.C. This has triggered a backlog need for pipeline capacity expansions on the NGTL system to move more gas entering Alberta from the west side of the province to be able to head intra Alberta, further east and south. Below is a map of the proposed 2021 NGTL expansion project needed for the change in sourcing of supply on the system.

[6] Chart and toll from the NEB Pipeline Profile.





In the summer season, prices can be extremely low and can go negative at times due to low demand, pipeline restrictions due to maintenance, construction and regulatory orders around safety investigations. The disconnect or lag effect of pipeline capacity can be seen in the chart below, showing a negative impact on price as supply increases. Pipeline capacity expansion and access to markets is slowly trying to catch up to supply. If they come into balance this will help stabilize the price of natural gas for the western market.

NGTL has instated a temporary tolling structure which allows for a change in protocol for firm and interruptible service only during planning maintenance periods between April 1 to October 31 of 2019 and 2020. The expectation is that the temporary protocol between firm and interruptible service would stabilize the AECO market during outages by allowing more gas to be able to move in and out of storage in Alberta. This would help stabilize the AECO price. s.13

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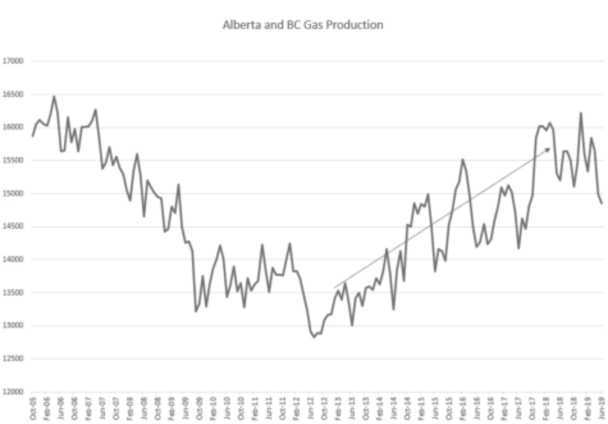
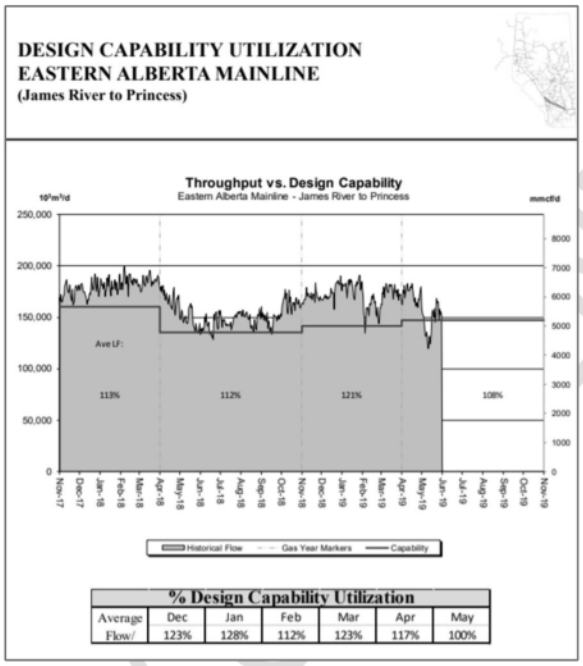
Chart 2

Chart 3



Planned pipeline capacity is in the works for NGTL, such as the 2021 expansion pipeline project which is currently before the Canadian Energy Regulator. This added capacity will be one of the last pieces to remove the bottleneck of moving gas from the west to the east, including almost 1 Bcf/d of delivery service out of Alberta at the Saskatchewan border. Chart 4 shows how supply is exceeding design capacity of the west side of the NGTL system at times, illustrating the need for new capacity.

Chart 4



Key Canadian hubs have been exhibiting extreme vulnerability due to capacity restrictions. Chart 5 is a recent example of Huntingdon price volatility with the Enbridge pipeline rupture on October 2018, reducing capacity for the rest of winter. The spikes are attributed to periods of reduced pressure during critical inspection and repair events during cold weather in February of 2019.

Chart 5

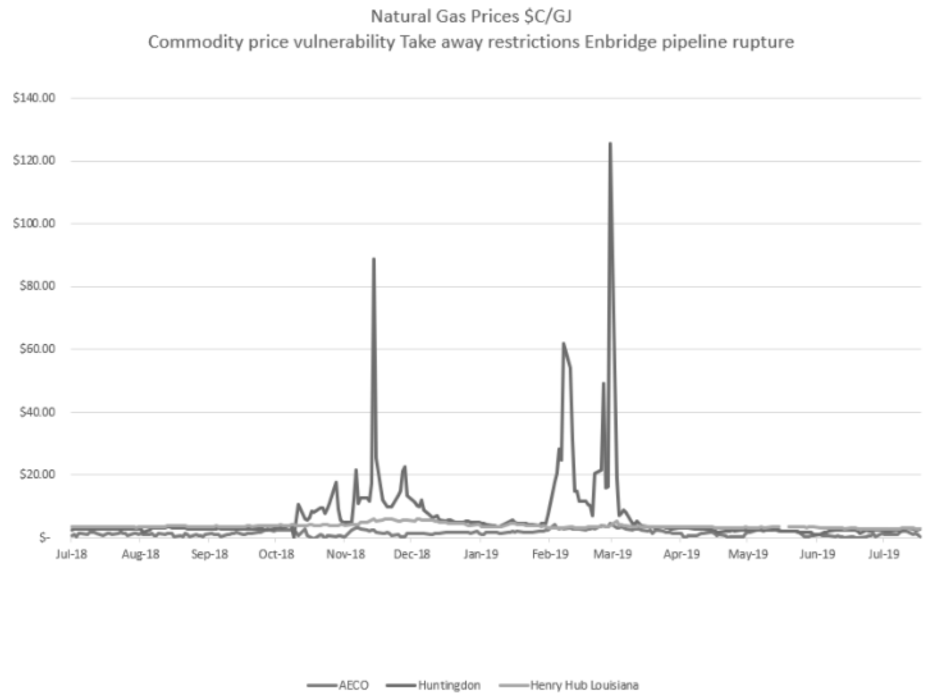


Chart 6 is another example of price volatility due to Alliance pipeline issuing a *force majeure* on June 18, 2019, halting all deliveries from Canada into the United States until operations were able to resume four days later. This impacted Alberta's price, pushing the day price in the negatives due to excess supply.

Chart 6

4.3 ROADMAP TO RECOVERY: REVIVING ALBERTA'S NATURAL GAS INDUSTRY 2018 - NATURAL GAS ADVISORY PANEL - KEY TAKEAWAYS FOR B.C.

The Natural Gas Advisory Panel was assembled by the Alberta energy minister to provide advice and recommendations to resolve persistently undervalued natural gas, extreme price volatility, intra- and inter-provincial natural gas transmission, natural gas storage and market access. Key findings requiring immediate action are: the need for LNG, development of infrastructure to address capacity and price, and a supportive regulatory governance.

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5. FISCAL COMPETITIVENESS

All investment decisions are made after in-depth analysis on key financials. Investments will be made where potential returns are greatest. Fiscal costs can be difficult to quantify due to differences in the various royalty and taxation structures of jurisdictions. This section – the most comprehensive of the report due to its importance and complexity – evaluates key fiscal structures in order to understand the cumulative cost imposed by a governing body.

5.1 ROYALTIES: COMPARISONS OF EFFECTIVE ROYALTY RATES AND UNITIZED ROYALTIES COLLECTED

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In the U.S., production costs are not allowed to offset gross royalties and there are also statutory limitations on the amount of post-production costs allowed in some oil and gas producing states. Both B.C. and Alberta allow for production as well as post-production costs either as deductions to offset gross royalties or as a factor for royalty rate adjustment.

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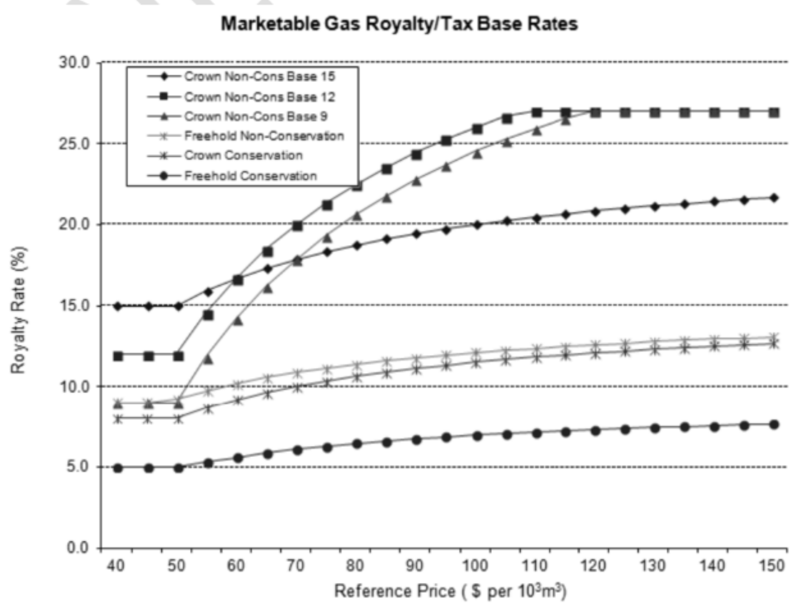
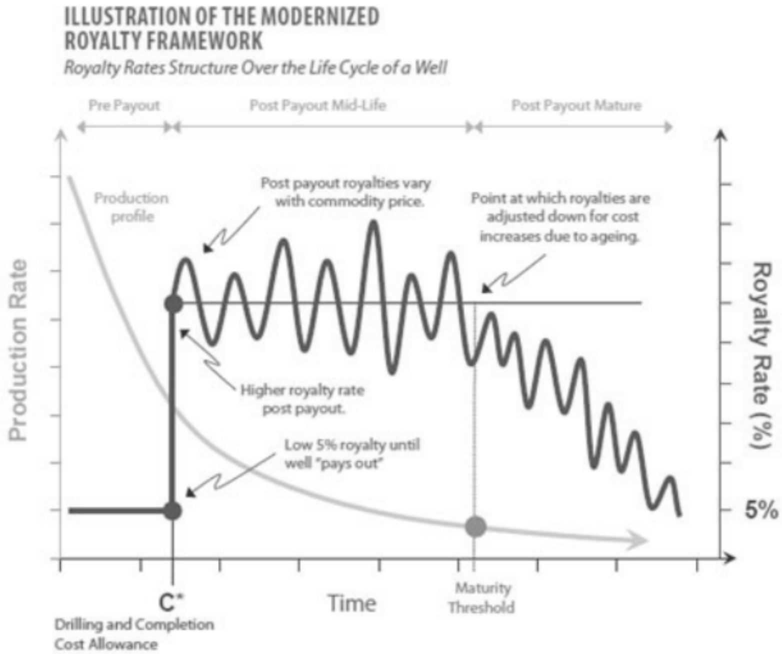
In Western Canada, most of the petroleum and natural gas resource rights are owned by the Crown, with the provinces owning approximately 80% in Alberta and almost 100% in B.C. The U.S. differs from the two Canadian jurisdictions in that most of mineral interest in the U.S. is controlled by private property owners.

The following two charts compare B.C. and Alberta natural gas royalty/tax base rates/rate structures:

B.C. Natural Gas Royalty/Tax Base Rates [1]



Alberta's Royalty Framework [2]



Natural gas royalty rates in B.C. are a function of price, tenure vintage, well productivity and classification. Note that B.C.'s curve reflects gross royalties at the value of the plant inlet. Alberta value gas at the plant outlet for royalty purposes. Natural gas liquids are valued at the sales value and the royalty rate on NGLs is 20% in B.C.

Alberta's new royalty regime, the "Modernized Royalty Framework" (MRF) took effect in 2017. The system involves adoption of a proxy Revenue Minus Cost (RMC) royalty structure for hydrocarbons. Under an RMC royalty structure, producers are charged a 5 percent royalty rate until cumulative revenues from the well exceed the well's Drilling and Completion Cost Allowance, otherwise know as C*. Higher royalty rates that vary with price are then applied after this point. Royalty rates are then reduced when a well reaches a marginally economic production level.

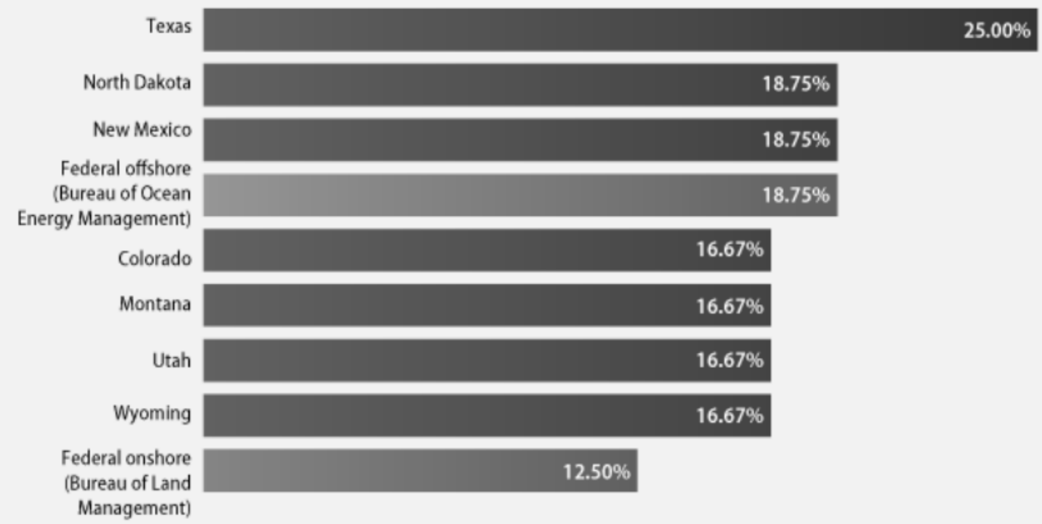
In the US, petroleum royalties are paid to mineral owners, which can be the state or federal government, individuals, Indian reservations, corporations, partnerships or any other entity. Royalties are generally levied at a rate of 12.5% to 30% (based on the lease or contract) of the gross wellhead value for all the petroleum produced [3].

Gross wellhead value is generally the posted spot price for the production location, or the actual revenue received, less any costs. The types of costs allowable are those for processing, storing and transporting the petroleum to the point of sale.

The following table compares U.S. federal and select state royalty rates for oil and gas extraction:

FIGURE 1

Comparing federal and state royalty rates for oil and gas extraction



Source: Center for Western Priorities, "A Fair Share: The Case for Updating Federal Royalties" (2013), available at westernpriorities.org/wp-content/uploads/2013/07/A-Fair-Share.pdf.

The Permian Basin in west Texas, for example, has been the site of the greatest regional increase in oil and gas production in recent years. Much of the development and production in the Permian Basin is occurring on the University of Texas System's University Lands, on which oil and gas companies pay a 25% royalty.

Pennsylvania's Guaranteed Minimum Royalty Act of 1979 guarantees landowners a minimum one-eighth (12.5%) royalty from oil and gas wells.

Private property owners, who control most of the mineral interest in the U.S., are charging royalty rates comparable to or higher than the federal and state governments in the U.S. In addition, Texas charges a 7.5% severance tax on oil and gas production. Pennsylvania does not charge severance tax on oil and gas production.

Cost Allowances

There are two categories of costs – production and post-production – associated with oil and gas.

Production costs are expenses of exploration and production, including drilling and completion costs. Production cost deductions are allowed in both B.C. and Alberta either as deductions to offset gross royalties or as a factor for royalty rate adjustment, but generally not allowed in jurisdictions in the U.S.

Post-production costs are costs incurred after production but before the sale. Such costs may include costs of treating, gathering, transporting, processing, compressing, fractionating, dehydrating, etc. Post-production costs are allowed deductions in B.C. and Alberta. But in the U.S. different interpretations of lease terms and state laws have created and continue to create controversies and lawsuits regarding post-production cost deductions in many oil and gas producing states.

British Columbia

In B.C., applicable production costs and post-production costs are allowed as deductions from natural gas sales value/gross royalties payable.

In addition, for certain types of gas well events, base royalty rates are reduced by factors related to the average daily rate of production from the well event. The types of well events that qualify for production-related rate reductions are low productivity, marginal and ultra-marginal well events.

The following costs, fees and credits can be deducted from natural gas sales values (to reduce the valuation basis for calculating royalties) or gross royalties payable in B.C.:

Post-Production Costs:

- Transportation charges incurred by producers to bring gas from plant outlet to a common pricing point (a pricing point to value all sales at plant outlets and downstream sales) are deducted from the natural gas sales value.
- For gas that is processed through producer-owned plants, the Gas Cost Allowance (GCA) is deducted to get an average value at the inlet of the plant. As a result, the GCA is deducted from natural gas sales values.
- For gas that is processed through plants that are not owned by producers, processing charges are deducted as invoiced. As a result, these charges are deducted from natural gas sales values, essentially shifting the price point to plant inlet.
- Producer Cost of Service (PCOS) allowance covers a producer's cost of field gathering, dehydration and compression of non-conservation gas, conserving conservation gas, and processing natural gas in the field for use as fuel in the field. The PCOS allowance is deducted from gross natural gas and natural gas liquids (NGLs) royalties payable.
- Credits attained through the Infrastructure Royalty Credit Program and Clean Growth Infrastructure Royalty Program are deducted from net natural gas and NGLs royalties payable after PCOS and deep well credit deductions (see section on production costs below).

Production Costs:

- Deep Well Credits: To encourage greater exploration for and development of deep gas resources, deep gas royalty incentives were introduced in 2003 and modified during the last decade. These are intended to encourage exploration for deep reserves of natural gas by offsetting the higher drilling costs. The Deep Discovery Well incentive is an exemption from payment of royalties for the first 36 producing months of the well. The Deep Well incentive is a deduction from royalties that is based on the depth and type of well. The Deep Re-entry incentive is also a deduction from royalties, which is based on well event depth and amount of incremental drilling. Tables that correlate well depths to drilling costs have been developed to provide royalty incentives that are related to higher drilling and completion costs.
    - Deep wells are separated into Tier 1 (shallower than 1900 metres) and Tier 2 (deeper than 1900 metres). Tier 1 wells pay a 6 percent minimum royalty on gas revenue (since April 2014); Tier 2 wells pay a 3 percent minimum royalty on gas revenue (since March 2013).
    - Royalty credits available to Tier 2 deep wells vary based on the location of the well (whether it is "east" or "west") and the concentration of Hydrogen Sulfide in the gas produced from the well (whether the well is "sweet" or "sour"). The exact value of the royalty credit available to a Tier 2 deep well is set out in Table 2 in section 7(7)(c) of the British Columbia Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation.
    - In 2018 average deep credit allocated for "east" deep well was $1.26 million and average deep credit allocated for "west" deep well was $2.28 million.
    - Deep Well Credits are deducted from net natural gas and NGLs royalties payable after PCOS deductions.

Alberta

In Alberta, applicable production costs and post-production costs are allowed as deductions from natural gas gross royalties payable or as a factor in determining lower royalty rates:

Post-Production Costs:

In Alberta the following costs and fees can be deducted from natural gas sales values/gross royalties payable:

- Transport costs,
- Gas gathering, compressing or processing fees for royalty clients who pay this expense on a fee for service basis,
- Capital and operating costs for royalty clients that own gathering, compressing and processing facilities.

Production Costs:

- Under MRF producers are charged a 5 percent royalty rate until cumulative revenues from the well exceed the well's Drilling and Completion Cost Allowance, C*.

Pennsylvania and Texas

In many oil and gas producing regions across the U.S, where most of the petroleum and natural gas resources are controlled by private property owners, production costs are generally the responsibility of oil and gas producers.

Many oil and gas producing states in the U.S. have regulations and laws that govern royalty rates and post-production cost deductions. For example, Pennsylvania's Guaranteed Minimum Royalty Act (GMRA) guarantees landowners a minimum one-eighth (12.5%) royalty from oil and gas wells. But in practice, after deducting post-production costs, the effective royalty rates can drop to as low as 7.5%. The private property owners' uproar over the practice of deducting post-production costs has sparked a lively political debate in Pennsylvania since 2015. Other states that have enacted laws that limit or even prohibit the practice of deducing certain post-production costs include Wyoming, Nevada, and Michigan.

The effective royalty rates in Pennsylvania and Texas for natural gas production on state-owned properties are estimated at 8.75% and 17.5% respectively, assuming post-production costs are 30% of the value of natural gas and by-products and the costs are deduced against gross royalties payable.

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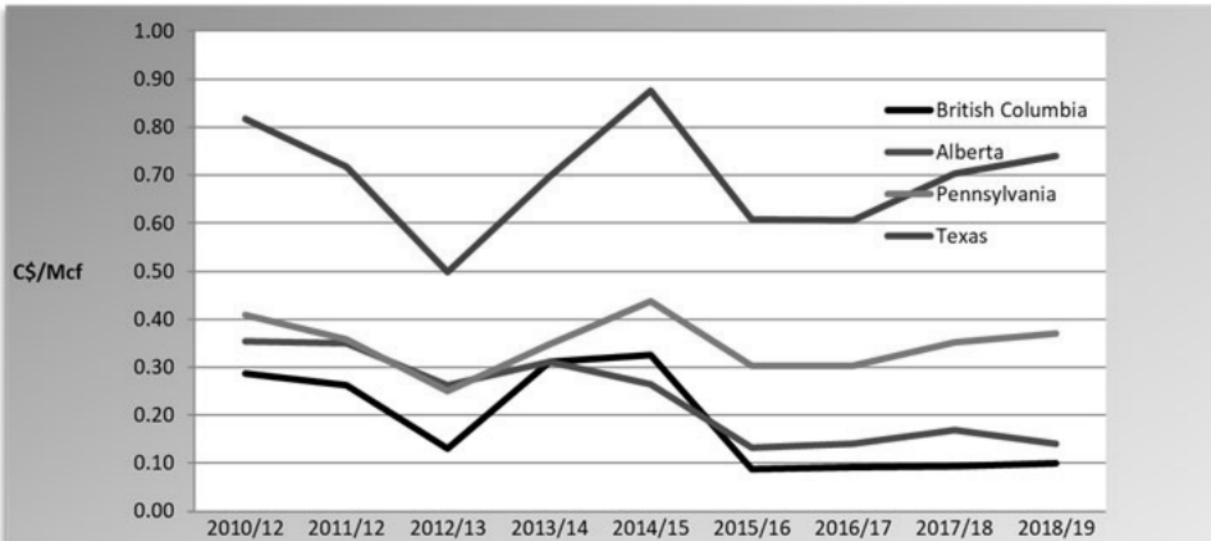
Unitized Royalties Collected by Jurisdictions

In this section, the amounts of royalties paid per unit production of natural gas (unitized royalties) in B.C. are compared to unitized royalties in Alberta, Pennsylvania and Texas (on state-owned properties only).

The following chart compares royalties per mcf of natural gas produced in B.C. to royalties per mcf of natural gas production in Alberta, Pennsylvania and Texas (NGLs royalties are included in natural gas royalties).

Natural Gas Unitized Royalties by Jurisdiction



	2010/12	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
British Columbia	0.29	0.26	0.13	0.31	0.33	0.09	0.09	0.09	0.10
Alberta	0.35	0.35	0.26	0.31	0.26	0.13	0.14	0.17	0.14
Pennsylvania	0.41	0.36	0.25	0.35	0.44	0.30	0.30	0.35	0.37
Texas	0.82	0.72	0.50	0.70	0.88	0.61	0.61	0.70	0.74

Notes:

1) Source: Ministry of Energy, Mines and Petroleum Resources
2) Canadian production data obtained from Canadian Association of Petroleum Producers' Statistical Handbook
3) Revenue data for each Canadian jurisdiction obtained from respective government budget documents and other public reports
4) Pennsylvanian production data obtained from PA Department of Environmental Protection and revenue data obtained from Pennsylvanian budget documents
5) Pennsylvanian unitized royalties were estimated assuming post-production costs were 30% of the value of natural gas and by-products.

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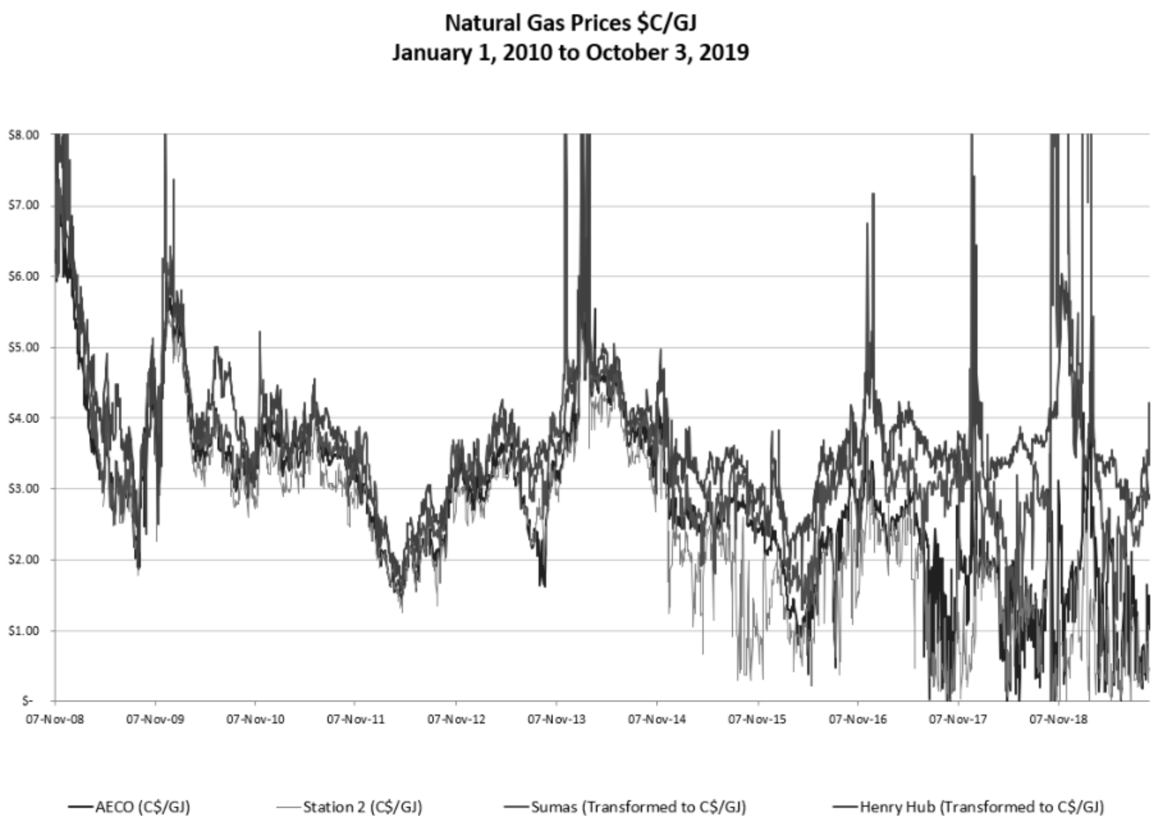
Over the past five years, B.C. and Alberta saw their natural gas unitized royalties decreased from 33 cents to 10 cents per mcf and from 26 cents to 14 cents per mcf respectively. The declines in unitized royalties for B.C. and Alberta were due to the widening of the differential between Henry Hub and Western Canadian Hub prices because of egress restrictions for Western Canadian production growth starting in 2014/15. Pennsylvania and Texas unitized royalties have been comparatively stable during the same period due to stable Henry Hub prices, as shown in the chart below:

Natural Gas Historical prices in North American Hubs



Source: Ministry of Energy, Mines and Petroleum Resources

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5.2 MONTNEY STUDY

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5.3 CONSUMPTION TAXES: CARBON AND MOTOR FUEL TAX

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The carbon tax was introduced in B.C. in 2008 as a revenue-neutral tax on carbon dioxide emissions (Murray and Rivers, 2015). The tax can be categorized as a consumption tax, since the amount taxed is based on the quantity of carbon dioxide emissions generated through the consumption of fuel needed to transport or produce associated goods. The current provincial rate of $40 per tonne is thus reflected in purchasing fuels and products produced or transported using mechanisms that result in emissions.

As a carbon emitting fuel, natural gas is subject to the carbon tax. It is also subject to a separate motor fuel tax when used to develop natural gas resources for market use. The impacts of both taxes are not limited to the sale and eventual consumption of natural gas, however activities to develop natural gas resources, including running generators, compressing stations, and transportation of water and equipment all produce emissions and add costs to companies developing natural gas resources in the Province.

This section examines the comparative cost of the carbon and motor fuel taxes to understand how these added costs compare with other jurisdictions and discusses the potential impacts of those costs. It will also examine the concept of carbon leakage and discuss the extent to which the consumption taxes result in increased carbon dioxide emissions in other jurisdictions.

The carbon tax in B.C. is applied at various stages of natural gas development, refining, and use. For this section, only the tax costs of fuel used in developing and refining natural gas will be considered. s.13; s.17

s.13; s.17

Alberta previously had a carbon tax which included a tax on natural gas use for upstream and midstream production and refining activities. With the repeal of the provincial tax in 2019, the federal carbon tax replaced the previous provincial tax with a new rate of $20 per tonne. s.13; s.17

s.13; s.17 Carbon pricing is not currently in effect in either Pennsylvania or Texas.

The B.C. motor fuel tax in is also applied at various stages of natural gas development in addition to the transportation of materials and products. Motor fuel tax is only applied to the development and refinement of marketable natural gas. To calculate the cost of the motor fuel tax to industry, only the tax applied to the development and refining of natural gas resources will be considered. s.13; s.17

s.13; s.17

There is no motor fuel tax on natural gas use currently present in Alberta, Pennsylvania or Texas. Motor fuel tax rates do exist for gasoline and diesel use, which impact transportation costs, however these costs are comparable between all four jurisdictions.

Carbon Leakage

Carbon leakage is defined by the Intergovernmental Panel on Climate Change as the "part of emissions reductions that may be offset by an increase of the emissions in non-constrained countries." (IPCC, 2014) Put another way, as countries introduce policies aimed at reducing carbon emissions, those policies may result in a corresponding increase in emissions-intensive production in other jurisdictions, or an increased use of fossil fuels based on lower prices. Carbon leakage is a problem created through a domestic focus on emissions reduction and presents a serious challenge to implementing effective emissions reduction policies given the global nature of climate change.

As examined by the Conference Board of Canada, carbon leakage currently occurs in the Canadian oil and gas sector, with approximately 10% of domestic emissions reductions being offset by a resulting increase of emissions in other sectors (Coad, 2017). Increasing the price on carbon domestically would magnify the leakage effect, with projections of up to 85% leakage at the carbon pricing cap of $80 per tonne set as part of the federal carbon tax.

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[7] The content of this section comes directly from the Sector Results Report, entitled *Low Carbon Industrial Strategy: GHG Benchmarking and Competitiveness Assessment of B.C. Industrial Sectors,* from the joint initiative.

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5.5 ELECTRIFICATION

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Electrification of the oil and gas industry in B.C. is identified as a key element in CleanBC and in the provincial and federal strategy of branding B.C.'s natural gas value stream as low carbon. Some participants in B.C.'s natural gas sector have chosen to electrify their operations. s.13; s.17

s.13; s.17

s.13; s.17

Natural gas production accounts for 10.2 MT of the Province's 64 MT of greenhouse gas emissions. Electrification in the upstream natural gas sector has reduced or avoided emissions by up to 0.6 MT per year. s.13
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Page 066 of 110

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5.6 LNG COMPETITIVENESS

B.C. stands to benefit from future increases in global LNG consumption, provided its LNG producers can remain competitive in global markets.

According to the International Energy Agency (IEA), global demand for natural gas is projected to grow four times faster than oil and is expected to be the second largest fuel in the coming decades. They expect global energy demand to rise by 1% annually to 2040. Low-carbon sources, led by solar photovoltaics (PV), will supply more than half of this growth, and natural gas, boosted by rising trade in liquefied natural gas (LNG) accounts for another third. The IEA also suggests that LNG will overtake pipeline gas as the main way of trading gas between regions by the later 2020s. They expect that Asia will lead LNG demand growth, with nearly half of incremental LNG production being consumed by developing Asian economies, mainly in China.

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Comparative Analysis

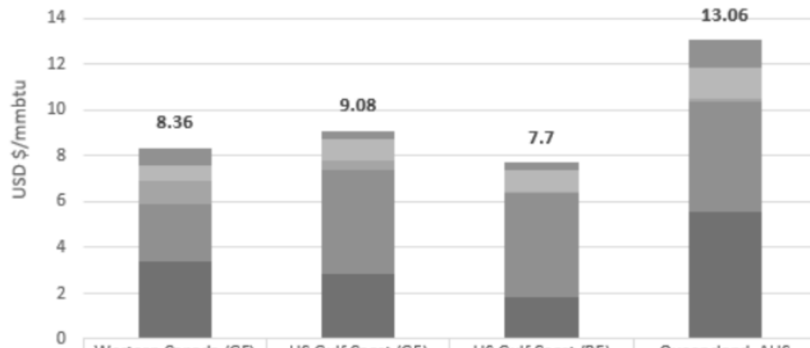
The economic competitiveness of a project is determined by the project's per unit supply cost, typically measured as US Dollars per million british thermal units (USD/mmBtu). Estimates of a project's supply cost are calculated using cash flow models, to determine the breakeven cost of supply over a period of time, typically 20 to 40 years. The lower the breakeven cost, the more competitive the project is relative to other projects.

In 2018, Canadian Energy Research Institute (CERI) published Competitiveness Analysis of Canadian LNG, in which it assessed the relative competitiveness of Canadian LNG projects to those of competing jurisdictions, in particular, Australia and the US Gulf Coast. Various costs are considered in estimating supply costs for comparison: capital expenses, natural gas, transportation costs, operating expenses, taxes (corporate, income and carbon tax) and landed costs which includes shipping.

Total supply costs associated with comparable jurisdictions are presented in Figure 1. For consistency, CERI took the cash flows and discounted them back to the present value using a 10% discount rate over the life of the project (assuming 30 years which doesn't include construction). We primary compared greenfield (GF) projects however we have included a US Gulf Coast brownfield (BF) project to demonstrate cost differentials.

According to CERI's analysis supply costs for western Canadian LNG projects are estimated at $8.36 USD/mmBtu, indicating their overall competitiveness is attractive among other greenfield LNG projects in this comparison (shown in Figure 1). When considering supply costs, capital costs and taxes, western Canadian projects are at a competitive disadvantage to the US Gulf Coast. In general, however, the western Canadian projects total supply costs are more competitive than greenfield projects in Australia and US Gulf Coast, but less competitive when comparing to a brownfield project from the US Gulf Coast.

Figure 1 – LNG Supply Costs - CERI



	Western Canada (GF)	US Gulf Coast (GF)	US Gulf Coast (BF)	Queensland, AUS
Taxes	0.78	0.37	0.32	1.2
OPEX	0.69	0.91	0.91	1.34
Transporation Cost	0.96	0.42	0.1	0.14
Feed Gas	2.51	4.52	4.52	4.8
CAPEX	3.42	2.86	1.85	5.58
Total	8.36	9.08	7.7	13.06

Western Canadian suppliers enjoy a relative competitive advantage in feedstock gas. They have a competitive advantage to the US and competitive disadvantage to Australia in shipping costs when delivering to North East Asia Market (Figures 2-3).

Figure 2 – Feedstock Gas Costs - CERI

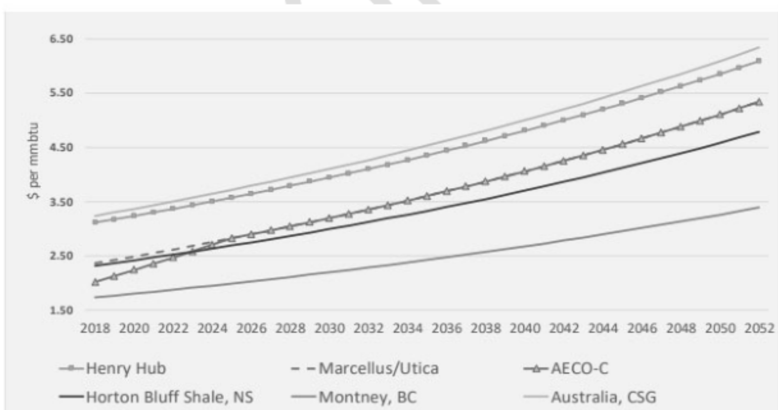
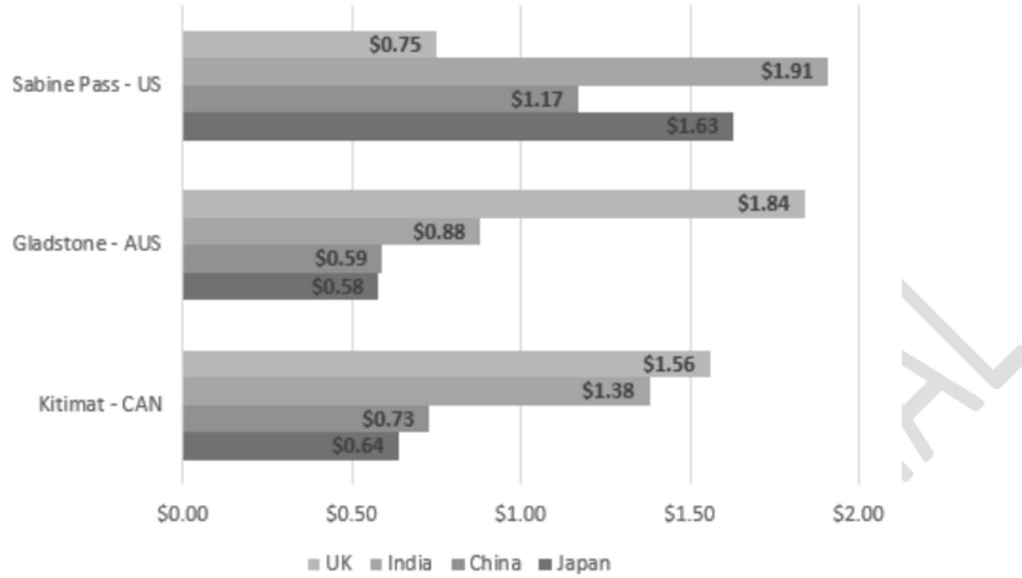


Figure 3 – LNG Shipping Cost USD $/mmbtu - CERI



Western Canadian LNG projects (unlike many other projects) are less competitive when factoring in new feedstock pipeline transportation costs between $.7 - $1.1/MMbtu (The Oxford Institute for Energy Studies, 2019). Many other global LNG projects have existing infrastructure which reduces their feedstock transportation cost.

LNG Competitiveness and Government Policies

While Canadian producers have comparative advantage from low-cost upstream natural gas supplies, additional competitiveness gains can be realized if B.C. LNG producers would secure even more cheaper feedstock sources, such as Station 2 price-based supplies, which normally trade at a big discount to the AECO-based gas supplies.

In March of 2018 the B.C. government announced several policy and fiscal measures to improve the competitiveness of the LNG sector. These measures include:

- Elimination of LNG income tax that had required LNG-specific tax rates, and retention of the Natural Gas Tax Credit;
- Reduction of electricity prices for LNG facilities to align them with other industrial consumers;
- Upfront PST relief for construction materials negotiated with LNG Canada. (The PST relief will materially reduce the massive upfront costs of getting the LNG plant built, however, it would be repayable as an "operational payment" over the following 20 years); and
- Conditional carbon tax rebates under the Clean Growth Incentive Program. A company can receive a carbon tax rebate of up to $30 per tonne of carbon dioxide equivalent (tCO_2e) if its GHG intensity is less than 0.22 tCO_2e per tonne of LNG produced (tCO2e/tLNG).

An essential part of LNG Canada's final investment decision (October 2018) was the B.C. government's March 2018 fiscal framework. The framework aims to put natural gas development on a level playing field with other industries in B.C. and to support good jobs and revenues for the Province, and to ensure British Columbians benefit from natural gas development.

CERI stated that the competitiveness of LNG projects could also improve after the recent federal government's decision to exempt fabricated industrial steel components (FISC) import duties for modules that are used in construction of LNG plants. LNG Canada and Woodfibre LNG have both received FISC import duty exemptions for their projects (Government of Canada, 2019).

In closing, Canada, has a competitive advantage in low upstream natural gas prices and shipping to North East Asia. With its vast and low-cost natural gas resources, B.C. stands to benefit from expected increases in global LNG consumption in coming decades, provided Canadian LNG producers become competitive in global markets, especially in North East Asia markets.

5.7 COMPARISON OF MARGINAL EFFECTIVE TAX AND ROYALTY RATES ON NATURAL GAS INVESTMENT: SUMMARY OF FRASER INSTITUTE FINDINGS

According to a Fraser Institute study, the marginal effective tax and royalty rates (METRR) on natural gas investment are 21.3% in Pennsylvania, 25.3% in Alberta, 31.9% in B.C., and 35.3% in Texas. The study indicates that B.C. is not as attractive as Pennsylvania and Alberta, but is more attractive than Texas, in terms of tax competitiveness.

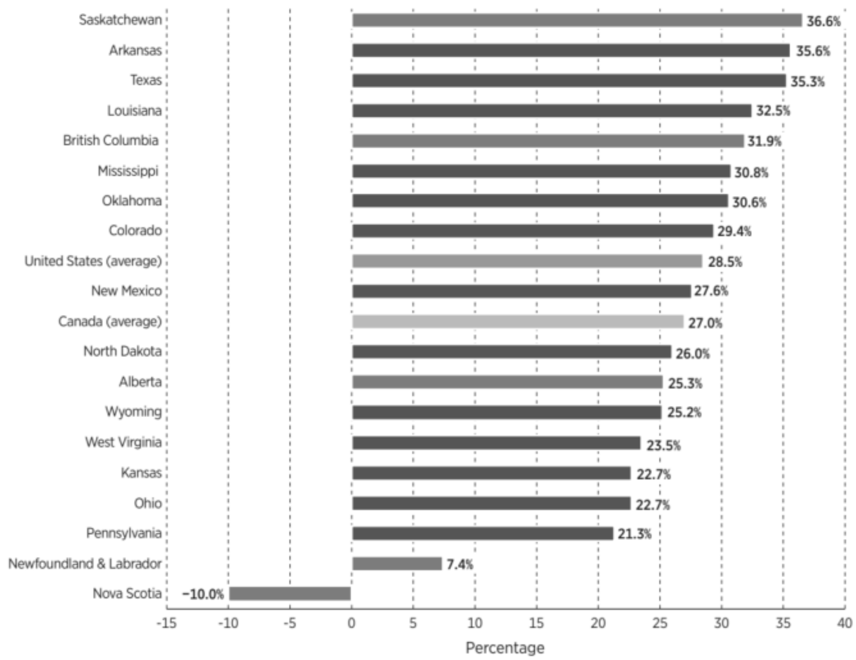
In *The Effective Tax and Royalty Rates on New Investment in Oil and Gas after Canadian and American Tax Reform* study, the Fraser Institute analyzes tax competitiveness in select Canadian and U.S. jurisdictions, considering the 2017 U.S. tax reform laws and the 2018 announcement of Accelerated Investment Incentive in Canada [5].

A summary measure, METRR accounts for corporate income taxes, sales taxes on capital purchases, capital taxes, transfer taxes, stamp duties, profit-based resource levies, and royalties as a share of the pre-tax rate of return on investments. METRR compares marginal tax competitiveness. All else being equal, tax will have some impact on investment, but it is only one among several criteria that impacts investment. Various non-tax factors such as production, exploration and development costs, distance to markets, the quality of the resource, skilled labour supply, regulations, infrastructure, political risk, and perhaps most important, market price, also affects a firm's investment decisions.

Oil and Gas Fiscal Regimes in Canada and the United States

According to the Fraser Institute, METRR in select Canadian and US jurisdictions on natural gas investment [6] are as follows:

Figure B: METRRs (%) on natural gas in select jurisdictions of Canada and the United States, 2018



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5.8 FRASER INSTITUTE REPORT – ANNUAL SURVEY 2018

The Fraser Institute published its 12th annual survey of petroleum industry executives and managers in November 2018. The survey ranks provinces, states and other jurisdictions according to perceived barriers to investment in oil and gas exploration and production facilities. Jurisdictions evaluated were assigned scores on each of 16 factors known to affect investment decisions. The scores were then used to generate a "Policy Perception Index" (PPI) that reflects the perceived extent of barriers to investment.

Survey participation declined since 2017. Results showed that jurisdictions with the highest PPI scores were in Canada, Europe, and the U.S. No Canadian jurisdiction ranked in the top 10. Nine of the top 10 PPI jurisdictions are in the U.S. British Columbia is still the least attractive province in Canada.

The survey was conducted in spring 2018 and included responses from 256 business leaders in the upstream sector. This compares with 333 responses in 2017 and was the third consecutive year when survey response rates for this study have declined. Eighty jurisdictions were evaluated, representing 68 percent of global oil and gas production. Survey scores were then tabulated and ranked according to PPI.

Survey Results

- British Columbia's scores remained low in 2018 (58th out of 80) and is still far below 2016 levels (39 of 96).
- British Columbia is still the least attractive jurisdiction in Canada for upstream oil and gas investment and declined from the top 50 percent in 2016, to the bottom 30 percent of jurisdictions in 2018.
- British Columbia's score declined most in the areas of the legal system, regulatory enforcement and regulatory duplication (81 percent negative).
- The cost of regulatory compliance and political instability remain major deterrents (80 percent negative).
- Negative responses for protected areas (71 percent negative) and land claims (76 percent negative) also remains high.

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Detailed results from the study, with comparisons to Alberta, Texas and Pennsylvania, can be found in Appendix E.

CONCLUSION

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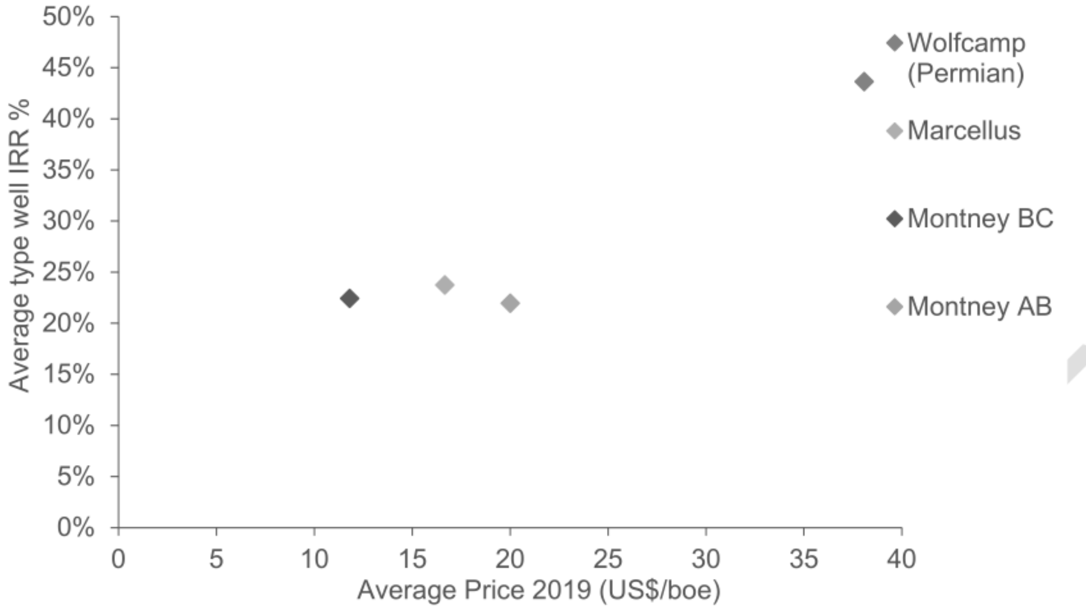
Wood Mackenzie H1 2019 North America Company & Play Analysis[10]

[9] Policy cost figures hyperlinked to sources within the study.

[10] Wood Mackenzie H1 2019 North America Company & Play Analysis Tool Fig #



Source: Wood Mackenzie

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Page 076 of 110

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AFTERWORD: PETER TERTZAKIAN, ECONOMIST, ARC ENERGY RESEARCH INSTITUTE

New technologies, social issues, environmental pressures and other forces of change are in the process of redefining how Canadians will source and consume their energy.

Each province has its own energy circumstance. Consumption is mostly a function of economic activity, wealth and climactic conditions. On the supply side, the energy mix is largely dependent on endowment and viable access to natural resources.

British Columbia is rich in two primary sources of energy: hydroelectricity and natural gas. The latter, which this short summary is concerned with, is both consumed and exported. Revenue generated from upstream natural gas sales totaled approximately $1.7 billion in 2018.

In the past year, LNG Canada (a consortium of multinational oil and gas companies led by Shell) has sanctioned a $40 billion project to create a natural gas supply chain from Northeast B.C., to the coast at Kitimat where it is liquefied, to markets in Asia. To fulfill future supply contracts, and be able to expand the supply chain, B.C. natural gas producers must be able to attract investment for development.

The challenge for natural-gas-focused companies in B.C. is to create an investable environment for natural gas supply and export, while demonstrating top-ranked environmental and social responsibility in the world. Secondary, though no less important challenges are to ensure that drilling for natural gas remains economically viable—able to generate sufficient returns for investors; and pursuant to ensuring productive capacity, the additional challenge of attracting value-added secondary industries into Northern B.C. to create further economic benefits including employment and taxes. Enbridge's Project Frontier is a good example of such secondary, value-added business.

At the moment, climate change mitigation strategies and policies have led to acute pressures on upstream and mid-stream natural gas producers in B.C. Taxes, emissions caps, carbon intensity targets and so on have created a challenging investment environment for all Canadian hydrocarbon-based businesses. The problem to-date has been exacerbated by the availability of natural gas investment alternatives in other parts of North America and the world where standards are less stringent.

To date, B.C. companies have been able to meet the challenges of operating in a business circumstance with some of the lowest natural gas prices in the world, coupled with most stringent environmental and social imperatives. However, despite the ability to operate under extreme pressures, their access to capital investment has been compromised like many other Canadian oil and gas companies at large. In short, investors have migrated to other natural-gas-rich jurisdictions that are not as restrictive—for example, Texas, Oklahoma and Pennsylvania.

How can British Columbia adapt to a carbon-constrained world, yet at the same time realize the prosperity that can accrue from one of the most prolific, low-cost endowments of natural gas in the world?

The answer potentially lies in understanding that stringent environmental restrictions on hydrocarbon industries have the potential to be viewed positively. In other words, B.C. has an opportunity to "brand" itself as the most responsible place in the world to do hydrocarbon extraction, processing, value-add and exports.

Changing the narrative such that hydrocarbons like natural gas from jurisdictions like B.C. are viewed as being premium products is paramount. To do so will require quantification, in other words, proof that B.C.'s environmental, social and governance (ESG) metrics are indeed top-tier.

To be competitive in the 2020s will require all energy companies, including hydrocarbons, to be low-cost, low-carbon-intensity and top-performance in terms of social and governance issues. B.C. natural gas industry has all qualities. But it has to prove its superiority and communicate it all.

The opportunity to do so is emerging in financial markets, where ESG metrics are in the process of being defined for sustainable finance. It's imperative for B.C. to be part of these conversations and influence its position.

Right now, it's difficult for most hydrocarbon companies to attract investment due to the broad-based environmental and social pressures described above. The money will come back, but selectively. Going forward into the 2020s, investors who provide debt and equity for large natural gas projects—upstream, midstream and downstream—will increasingly discriminate between companies and jurisdictions that can verifiably prove the best ESG performance and those who can't. B.C. can be one of the rare jurisdictions that can.

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APPENDIX A: GEOLOGICAL REVIEW OF PLAYS AROUND THE WORLD

Montney Play Trend of Alberta

In Alberta the Montney Play Trend is a continuation of northeastern British Columbia with subtle geological differences. Areal extent is greater than that for British Columbia but much of the formation is thin. Reported values for organic content suggest slightly lower averages in Alberta [3].

Duvernay Formation of Alberta

The Upper Devonian Duvernay Formation of central Alberta is comprised of shales and mudstones [3], and is the basinal equivalent of the Leduc Formation, which greatly accelerated early development of the oil industry in western Canada. It has high silica content, so it is very brittle. Development is in the early stages, so little production information is available, although it seems likely that it will be liquids rich composed largely of oil and natural gas liquids.

Spirit River of Alberta

The Spirit River Formation is composed of dark grey shale thinly interbedded with siltstones and sandstones [3]. Conventional production is possible from this formation in places. It is in the early stages of development so little information is available and numbers for technically recoverable resource have not yet been published.

Marcellus Shale of the Appalachian Basin Pennsylvania

The Marcellus Shale of the U.S. northeast is one of the world's most prolific unconventional gas producers. It is composed of variable fissile and fractured carbonaceous silty shale, calcareous shale and black limestone. It is thickest in south-central New York state. Western parts of the basin are liquids rich where it is somewhat under-pressured [5].

Each well uses 11000 – 15000 cubic metres of water for completion [6]. Water is sourced from surface sources or groundwater. Some flowback water is re-used and the rest is disposed locally. Disposal costs are high in the area [7][8]. Confirmed seismic events, attributed to water disposal, of approximately 3 Magnitude have been on the increase [9].

Haynesville Shale of the Gulf Coast of Louisiana and East Texas

Haynesville shale is a heterogeneous mudstone with varying amounts of clay and calcareous components. As one of the earlier basins to be developed for shale gas many wells underperform relative to their potential but are reportedly good candidates [10] for re-completion using more recent technological approaches.

Average water use for completions is comparably high at around 21500 cubic metres per well [11]. Little of the return water can be re-used so must be disposed. East Texas has many disposal wells, so disposal costs are mitigated. Powerful earthquakes up to 4.8 Magnitude have been attributed to disposal.

Cana–Woodford Shale of Oklahoma

Reservoir rock is composed of black shale with interbedded chert, siltstone, sandstone, dolostone and lighter coloured shale. It has a high silica content that makes the rock brittle and easy to frack. However, cherty interbeds can cause drilling problems.

The Oklahoma area has been heavily impacted by many 3 Magnitude or greater seismic events due to wastewater disposal [12].

Utica Shale of the Appalachian Basin

Utica shale is composed of inter-bedded organic rich fine-grained limestone and shale. The combination of low clay content, abundance of carbonate matrix and natural fractures make it highly frackable [13]. Reports of seismic events due to fracking or water disposal could not be found. Unverified informal reports suggest that relatively little water is typically used for fracking, and that combined with low formational water saturation, results in small amounts of flowback water to be disposed. But, like the Marcellus, disposal costs are high in the region.

Eagleford Shale of the Texas Gulf Coast

The Eagleford Formation is composed of inter-bedded dark shales, marls and thin bedded limestone [14]. High carbonate content makes the rock brittle and highly frackable. The reservoir is divided into deep dry gas portions and shallower liquids rich regions.

No reports of induced seismicity could be found. Water use is high at up to 20000 cubic metres for each well completion [11].

Barnett Shale of the Permian Basin of Texas (Fort Worth Basin)

The Barnett Shale is composed of siliceous and calcareous mudstone [15] which deepens and thickens to the northern part of the basin. It is relatively rich in silica, poor in clay and naturally fractured, which are features that enhance frackability.

Many small earthquakes have been attributed to wastewater disposal [16]. Wastewater returns are high and relatively abundant amounts of formation water are produced as well [11].

Wolfcamp Shale of the Permian Basin of Texas (Midland and Delaware Basins)

The Wolfcamp Shale is a very thick formation composed of a heterogeneous assembly of interbedded mudstones, turbiditic clastics and evaporates in restricted portions of the basins [17]. Carbonates dominate the edges of the basins and clastics mid-basin. Operators have sub-divided the Barnett into four intervals A – D. Upper layers A and B have attracted most of the drilling so far.

Note on Technically Recoverable Resource

In Table 1 the column for technically recoverable resource (TRR) presents an estimated volume of hydrocarbons that can be produced using current technology. For U.S. basins those estimates are taken from reports by the US Energy Information Administration. Canadian values were calculated by the National Energy Board in conjunction with provincial jurisdictions. In western Canada TRR is referred to as ultimate potential marketable. The definitions differ slightly, but they essentially both refer to hydrocarbons that can be realistically produced.

TABLE 1 North American Unconventional Basins

Unconventional Basin	Area (hectares)	Thickness (metres)	Depth Below Surface (metres)	Target Formations and Age	Average Organic Content %	CO2% / H2S%	Remaining Reserves	Technically Recoverable Resource
Montney Play Trend of Northeastern British Columbia [1],[2], [29],[30]	2,600,000	30 - 300	1,400 - 3,800	Middle Triassic Montney and Doig Phosphate	2	less than 1/ less than 1	35Tcf, 29 million barrels NGL	400 TCF
Montney Play Trend of Alberta [3], [31]	3,900,000 dry gas plus wet gas	0 - 300	500 - 4500	Middle Triassic Montney and Doig Phosphate formations	0.8%			178 Tcf, 1.9 billion barrels NGL, 1.1 billion barrels oil
Duvernay of Alberta [3],[32]	1,550,000 dry gas plus wet gas	2 -99	2000 - 3500	Upper Devonian Duvernay Formation	2.6%	0.68 / 0.01 (alberta geoscout)	1.1Tcf, 34 million barrels oil, 145 million barrels NGL	77 Tcf , 3.4 billion barels oil, 6.3 billion barrels NGL
Spirit River of Alberta [3]	368,000 wet gas	100	250 - 3700	Lower Cretaceous Wilrich Member of the Spirit River Formation	0.1 - 7%	?	?	?
Marcellus Shale of the Appalachian Basin [5],[6],[14],[35],[36],[43]	18,600,000	0 - 290	30 - 3000, mostly 1500 metres or more	Middle Devonian Marcellus formation	1 - 11%	no values found	77 Tcf, 143 million barrels oil	263 Tcf, 13 billion barrels NGL
Haynesville Shale of the Gulf Coast of Louisiana and East Texas [10],[14],[33],[34],[35]	2,300,000	80 - 100	3000 - 4000	Upper Jurassic Haynesville Formation	2 -6%	Informally reported to be high by several sources. No measured values found.	36Tcf	122 Tcf dry gas
Cana - Woodford Shale (also known as Anadarko-Woodford) of Oklahoma [12],[14],[35],[43]	178,000	60	4100	Upper Devonian Woodford Formation	3 -10%	no values found	?	17 Tcf, I billion barrels oil, 1 billion barrels NGL
Utica Shale of the Appalachian Basin [35],[37],[38],[39],[43]	12,800,000	30 - 150	underlies the Marcellus Shale 2000 - 4000	Upper Ordovician Utica Formation	2 - 7%	no values found	27Tcf	194 Tcf, 2 billion barrels oil and 6 billion barrels NGL
Eagleford Shale of the Texas Gulf Coast region [14],[35],[40],[43]	5,200,000	80	1200 - 3700	Upper Cretaceous Eagleford Group	4.5%	no values found	27 Tcf, 5 billion barrels oil and NGL[11]	55 Tcf, 13 billion barrels oil and 7 billion barrels NGL

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* Discovered Raw Gas as reported in a confidential report prepared for the Ministry of Energy Mines and Petroleum Resources

Barnett Shale of the Permian Basin (Ft Worth) of Texas [14],[15],[16],[34],[35],[41],[42],[43]	1,700,000	100	2300	Misissippian Barnett Shale	3%	no values found	19 Tcf and 20 billion barrels oil and NGL	22 Tcf and 1 billion barrels NGL
Wolfcamp Shale of the Permian Basin - Midland and Delaware Basins [17],[34], [35],[42],[43],[44],[45]	2,600,000	60 - 2100 in Delaware Basin; 120 - 500 in Midland Basin	2000	Permian Wolfcamp Formation	2 - 8% EIA Permian Basin Wolfcamp Shale Play Geology review	no values found	32 Tcf and 8 billion barrels oil and NGL	84.1 Tcf 37 billion barrels oil and 12 billion barrels NGL

Offshore Producers of LNG

Gorgon -Janz Lo Carnarvon Basin of West Australia

Gorgon is located on an uplifted fault block in Triassic aged Mungaroo Formation. Closure is by an anticlinal structure [18]. Reservoir rock is composed of a number of sandstone beds with good porosity and permeability. Jansz production is from another uplifted structure from the late Jurassic Jansz formation. Resource assessments by the Australian government [19] present figures for basins and not for individual fields such as Gorgon- Janz Lo. As a result, the numbers for TRR are taken from the operating company website and method of estimation is unknown.

Plans have been made for carbon capture and storage (CCS) from operating facilities [20] [21], but no information could be found to confirm date of operation*.

Qatar: North Field (South Pars in Iran)

The Khuff Formation is made up of five cycles (K1 to K5) of carbonate-evaporite deposits. K2 and K4 are the main reservoir units. The other units form permeability barriers or are poor reservoir quality. This inherent heterogeneity is considered as the most significant geological feature likely to affect sustainable field production performance. The complexity is a result of changing sedimentary conditions and variations in diagenesis, with relatively high rates of deposition in environments oscillating between shallow intertidal and open marine. The formation was first deposited as a carbonate platform during the mid-Permian, but the climate gradually became warmer and more arid, resulting in the deposition of evaporates and dolomitization of the carbonates. Sediments dip slightly on the underlying Qatar domal structure, but trapping appears to be mainly stratigraphic [22][23][24].

No specific plans have been announced for CCS.

Snohvit: Norwegian Barents Sea

The reservoir consists of Lower to Middle Jurassic sandstones deposited in a transgressive coastal to inner shelf sequence. Three wells, each situated in a separate fault block, define the Snohvit field. The wells have common fluid contacts. Reservoir properties are fair, with a porosity of 15% and permeability from 200 to 500 md in the main reservoir. The water saturation in the gas zone averages 10% and varies from 3 to 26%. Thickness varies greatly due to local unconformities over local uplifts. Erosion or non-deposition in places result in only one two formations being present in places [25][26][27]

CCS has been practiced at Snohvit since 2008 and roughly 700,000 tonnes of CO_2 per year are sequestered into a formation separate from the producing horizon [28].

*A recent news report [47] indicates start-up of a carbon dioxide injection system at the Gorgon natural gas facility.

Note on Technically Recoverable Resource

Offshore estimates shown in Table 2 were done by their own technical agencies, or unknown consultants, and their definitions for recoverable resources may differ slightly. For Table 2 the term TRR has been used for hydrocarbon volumes they consider to be realistically producible. Estimate methodologies are not clearly referenced.

TABLE 2 Offshore Conventional Basins

Basin (most International LNG Basins are Conventional)	**Area** (hectares)	**Thickness** (metres)	**Depth Below Surface** (metres)	**Target Formations and Age**	**CO2% / H2S**	**Remaining Reserves**	**Technically Recoverable Resource**
Gorgon -Janz Lo Carnarvon Basin of West Australia [18],[19],[20],[21],[48]	Several block faulted structures, closure area not published	Approx 180 metres net pay	Water depth is around 250 metres for Gorgon, 1300 metres of Jansz Lo; total well depths average 4300 metres	Late Triassic Mungaroo Formation	8.8 average, 1% Jansz Lo, 14% Gorgon / 0 H2S in both fields	17.6 Tcf	40 Tcf and 6.7 billion barrels oil
Qatar: North Field (South Pars in Iran) [22],[23],[24]	600,000 in Qatar portion(70% in Qatar and 30% in Iran)	400	2700 (offshore in 65 metres of water)	Permian-Triassic aged Khuff Formation (also known as Triassic Kangan and Upper Permian upper Dalan formations)	1.8 / 0.5	?	900 Tcf plus 10 billion barrels condensate in Qatar
Snohvit: Norwegian Barents Sea. [25],[26],[27]	?	Highly variable due to local unconformities.	2600 metres, 300 metres water depth	Lower to Middle Jurassic Sto Formation and Lower Jurassic Nordmela and Tubaen Formations	5-8 CO2	5.5 Tcf, 101 million barrels condensate	7.4 Tcf, 155 million barrels condensate

APPENDIX B: ROYALTIES - EFFECTIVE ROYALTY RATES

British Columbia

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Alberta

2018/19		Alberta
Net Natural Gas Royalties (including NGL royalties) in $millions	$	540
Average Alberta Natural Gas Reference Price (ARP) ($/GJ)	$	1.34
NOVA Transport Charges ($/GJ)	$	0.18
Natural Gas Production (in PJ)		4,026
Natural Gas Value at Plant Outlet in $millions	$	4,658
Average price for Pentane based on Sproule ($/bbl)	$	79.31
Pentanes and condensate production (bbl/d)	$	322,677
Condensate pipeline and fractionation fees ($/bbl) (based on Third-party report)	$	5.09
Pentanes and condensate value in $millions	$	8,742
Average price for Propane based on Sproule ($/bbl)	$	27.00
Propane production (bbl/d)	$	210,715
Propane pipeline and fractionation fees ($/bbl) (based on Third-party report)	$	5.09
Propane value in $millions	$	1,685
Average price for Butane based on Sproule ($/bbl)	$	33.65
Butane production (bbl/d)	$	124,542
Butane pipeline and fractionation fees ($/bbl) (based on Third-party report)	$	5.09
Butane value in $millions	$	1,298
Average price for Ethane based on Sproule ($/bbl)	$	6.90
Ethane production (bbl/d)	$	225,811
Ethane pipeline and fractionation fees ($/bbl) (based on Third-party report)	$	5.09
Ethane value in $millions	$	149
Total natural gas and NGL value in $millions	$	16,533
Effective Royalty Rate (Net natural gas royalties/Total natural gas and NGL value)		3.27%

APPENDIX C: RESOURCE COST OF SUPPLY - RESOURCE BASE SUPPLY SUMMARY

BRITISH COLUMBIA MONTNEY SUPPLY SUMMARY (MCDANIEL, 2019)

Region	Development Layer (U/M/L)	Discovered Remaining Inventory	Total Remaining Inventory	Discovered Undeveloped Raw Gas (Bcf)	Total Undeveloped Raw Gas (Bcf)
Heritage	Lower	2,672	3,856	29,740	42,625
	Middle	1,348	3,144	12,507	27,617
	Upper	3,090	3,671	39,638	45,852
	Combined	7,109	10,671	81,885	116,094
Northern	Lower	6,053	12,003	57,771	109,010
	Middle	4,952	11,125	42,920	91,202
	Upper	6,621	11,527	57,425	96,366
	Combined	17,626	34,655	158,116	296,577
Heritage + Northern	Lower	8,725	15,859	87,511	151,635
	Middle	6,300	14,269	55,428	118,819
	Upper	9,710	15,198	97,063	142,217
	Combined	**24,735**	**45,326**	**240,002**	**412,672**

APPENDIX D: MONTNEY STUDY - EVALUATION PARAMETERS

Energy, Mines, and Petroleum Resources (EMPR), Oil and Gas Division, utilized base information from the McDaniel Resource and Cost of Supply study to run economic scenarios in Value Navigator to evaluate future economics of Sunrise Wet and Altares.

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APPENDIX E: FRASER INSTITUTE 2018 SURVEY

The Fraser Institute's final analysis of the 2018 PPI survey indicates that policy perceptions, as they relate to investment attractiveness in the upstream, has increased in many of the world's regions. The United States remains the most attractive region for upstream investment, followed by Europe. Canada's score declined in 2018 but still ranks well globally.

Table 1: Survey Factors Used to Develop Policy Perception Rankings and PPI Ranking

Factor	Description	AB Rank (of 80)	B.C. Rank (of 80)	PA Rank (of 80)	TX Rank (of 80)
Fiscal terms	Includes licenses, lease payments, royalties, gross revenue charges, but *not* personal or corporate income taxes	54	53	28	5
Taxation	Total tax burden including personal, corporate, payroll, capital taxes, and complexity of tax compliance	62	66	35	3
Environmental regulations	Stability of regulations, consistency and timeliness of regulatory process	65	69	67	4
Regulatory enforcement	Uncertainty regarding the administration, interpretation, stability or enforcement of existing regulations	48	56	43	1
Cost of compliance	Related to filing permit applications, participating in hearings, etc.	69	74	54	2
Protected areas	Uncertainty concerning what areas can be protected as wilderness or parks	60	69	42	6
Trade barriers	Tariff and non-tariff barriers to trade and restrictions on profit repatriation, and currency restrictions	45	53	29	11
Labour regulations	The impact of labour regulations, employment agreements, labour militancy or work disruptions	33	45	42	7
Quality of infrastructure	Includes access to roads, power availability, pipelines	21	39	45	6
Quality of geological database	Includes quality, detail, and ease of access to geological information	10	13	37	21
Labour availability and skills	The supply and quality of labour, and the mobility workers have to relocate	23	31	15	25
Disputed land claims	The uncertainty of unresolved claims made by aboriginal groups	69	75	24	10
Political stability	No stated definition	52	69	35	5
Security	The physical safety of personnel and assets	22	37	35	16
Regulatory duplication/consistency	Includes federal/provincial or interdepartmental overlap	56	71	12	6

Factor	Description	AB Rank (of 80)	B.C. Rank (of 80)	PA Rank (of 80)	TX Rank (of 80)
Legal system	Legal processes that are fair, transparent, non-corrupt, administered efficiently, etc.	16	36	25	6
Overall Public Perception Index	Aggregate of scores using above 16 criteria	43	58	36	8

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Objective and Approach

sentis

Objective

To understand the impact of recent and proposed regulatory changes on the BC oil and gas industry

Approach

Quantitative Survey
with BC oil and gas industry stakeholders

- BCOGC provided Sentis with a list of stakeholder contacts. These contacts were selected because they subscribe to information bulletins issued by the BCOGC.
- Prior to the launch of the survey, BCOGC sent a notification email to stakeholders alerting them to the upcoming survey opportunity. Sentis emailed the survey invitation, and initiated reminders by email and by phone to ensure that the stakeholders surveyed reflected the broader contact list with respect to type of organization and occupational role. A total of 161 surveys were completed between Jul 31, 2019 and Aug 27, 2019. The types of organizations, and the roles of the survey participants in these organizations are presented on slide 15.
- The survey assessed awareness, and the impact of, recently implemented as well as proposed regulatory changes in BC. Survey participants first indicated their level of awareness and familiarity with seven regulatory changes. They were then presented with a description of each change and rated how they expected the change to impact key indicators of regulatory efficiency, including the time it takes to obtain project approvals, the clarity of the requirements to proceed with projects and the financial cost of meeting regulatory requirements. The presentation of the regulatory changes was randomized across participants to control for order effects.
- Survey participants then rated the impact that they expect the regulatory changes, taken together, will have on the likelihood that major resource projects will be approved, on the efficiency with which BCOGC makes regulatory decisions, and on safe and responsible energy resource management in BC.
- Survey participants also rated BCOGC's overall effectiveness at regulating upstream oil and gas activities in BC and were asked to provide suggestions regarding how BCOGC could be more effective at regulating upstream oil and gas activity.

2

Objective and Approach

sentis

Approach (continued)

In-depth Interviews

- The goal of the in-depth interviews was to learn how the current regulatory environment in BC is impacting efficiency, to gather suggestions regarding how greater efficiency can be achieved, as well as how the BC Oil and Gas Commission compares to other industry regulators.
- BCOGC provided Sentis with a list of oil and gas industry contacts who occupy managerial or executive-level roles in upstream oil and gas companies or in industry associations. The contact list was developed to ensure that the views of those who interact with the BCOGC at various levels were captured – e.g., those who interact with BCOGC's frontline and field staff, and those who interact with BCOGC's senior management.
- A total of 22 interviews were conducted by phone, each lasting approximately 30 minutes. In some cases, more than one representative from the organization participated in the interview. Also, it was common for the interviewees to canvas their internal colleagues prior to the interview to ensure that different perspectives within their organization were expressed during the interview.

3

Awareness of Recent or Proposed Regulatory Changes

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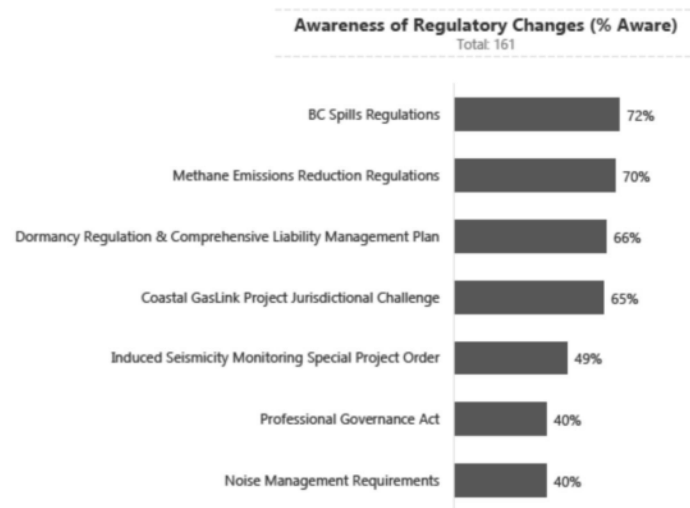
Awareness of the regulatory changes ranged from 40% (Noise Management Requirements and the Professional Governance Act) to 72% (BC Spills Regulations).

Overall, two-thirds of stakeholders (68%) were aware of at least four out of seven of the regulatory changes.



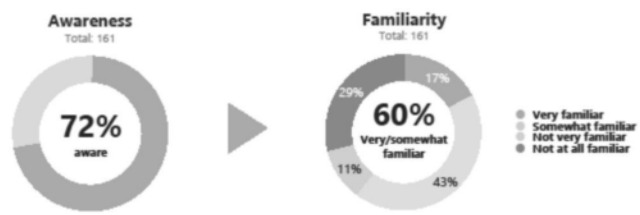
5

BC Spills Regulations

sentis

Six-in-ten of stakeholders indicated that they are at least somewhat familiar with the BC Spills Regulations.

Eight-in-ten stakeholders indicated that they expect the regulations will increase the financial costs to meet regulatory requirements, with most of these (50%) expecting that financial costs will increase somewhat.

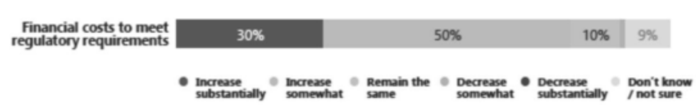


What are the BC Spills Regulations?

The BC Spills Regulations are intended to improve preparedness, response and recovery from potential spills. Approved in October 2017, the first phase of the regulations established a standard of preparedness, response and recovery necessary to protect BC's environment. The BC Government is working on implementing the second phase of regulations. This second phase of regulations aims to:

- Reduce response times following a spill
- Create geographic response plans, which consider the unique characteristics of sensitive areas
- Provide compensation for loss of public use from spills, including economic, cultural and recreational impacts
- Maximize the application of regulations to marine spills

Expected Impact of Initiative on:



6

Methane Emissions Reduction

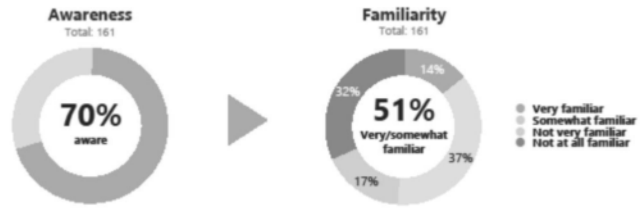
sentis

Just over half (51%) of stakeholders indicated that they are at least somewhat familiar with the new Methane Emissions Reduction regulations.

Just over eight-in-ten stakeholders (82%) indicated that they expect the new methane regulations will increase the financial costs to meet regulatory requirements, with four-in-ten (39%) expecting that financial costs will increase substantially.

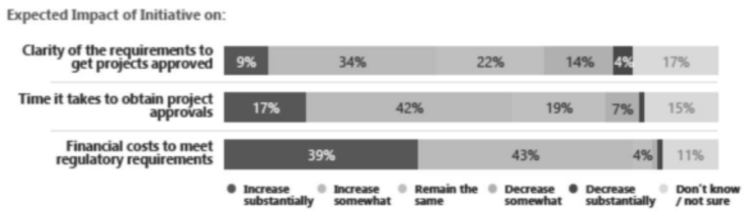
Just under six-in-ten stakeholders (59%) expect that the new methane regulations will increase the time it takes to get project approvals – with most of these (42%) expecting that project approval times will increase somewhat.

Overall, 43% of stakeholders expect that the new methane regulations will increase the clarity of the requirements to get projects approved, with most of these (34%) expecting that the clarity of the requirements will increase somewhat.



What are the new Methane Emissions Reduction regulations?

On Jan. 16, 2019, the BC Oil and Gas Commission announced new regulations to reduce methane emissions from upstream oil and gas operations to meet or exceed federal and provincial government methane emission reduction targets. Both the federal and BC provincial government targets aim to reduce methane emissions by 45 per cent by 2025. The new regulations come into effect on Jan. 1, 2020.



Dormancy Regulation and Comprehensive Liability Management Plan

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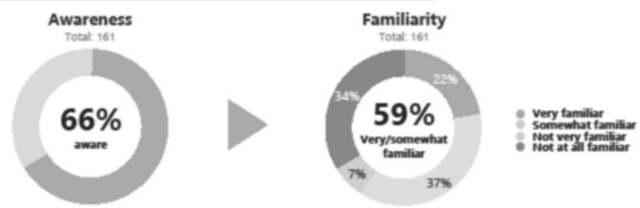
Just under six-in-10 (59%) of stakeholders indicated that they are at least somewhat familiar with the Dormancy Regulation and Comprehensive Liability Management Plan.

Just over eight-in-ten stakeholders (84%) indicated that they expect the Dormancy Regulation and Comprehensive Liability Management Plan will increase the financial costs to meet regulatory requirements, with 45% expecting that financial costs will increase substantially.

Just under half (49%) of stakeholders expect that the dormancy regulation and plan will increase the time it takes to get project approvals – with most of these (32%) expecting that project approval times will increase somewhat.

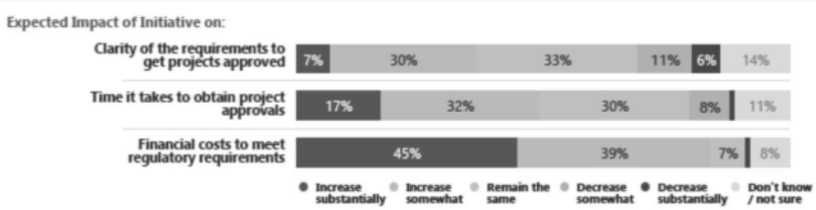
Overall, 37% of stakeholders expect that the new methane regulations will increase the clarity of the requirements to get projects approved, with most of these (30%) expecting that the clarity of the requirements will increase somewhat.



What is the Dormancy Regulation and the Comprehensive Liability Management Plan?

The Dormancy Regulation and Comprehensive Liability Management Plan details the steps and actions required and being taken to protect public safety and safeguard the environment by:

- Ensuring adequate funding for the Orphan Site Reclamation Fund.
- Imposing timelines for the abandonment, remediation and reclamation of wells.
- Creating opportunities to collaborate with Indigenous communities on oil and gas well restoration.
- Addressing potential issues of corporate health or operational risk with companies before any development activity can take place.



Jurisdictional Challenge for the Coastal GasLink Pipeline Project

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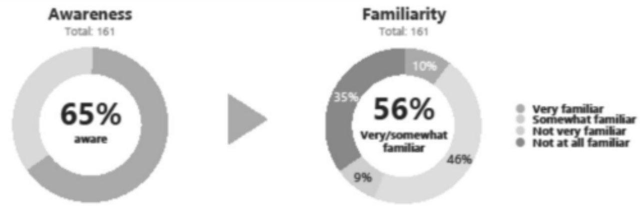
Over half (56%) of stakeholders indicated that they are at least somewhat familiar with the Jurisdictional Challenge for the Coastal GasLink Pipeline Project.

Just under eight-in-ten stakeholders (79%) indicated that they expect the jurisdictional challenge will increase the financial costs to meet regulatory requirements, with most of these (57%) expecting that financial costs will increase substantially.

Seven-in-ten stakeholders expect that the jurisdictional challenge will increase the time it takes to get project approvals – with most of these (52%) expecting that project approval times will increase substantially.

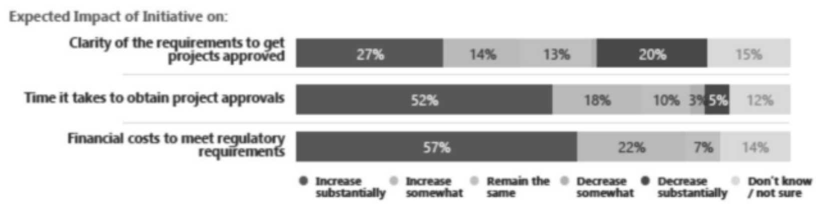
Stakeholders' expectations regarding how the jurisdictional challenge will impact the clarity of the requirements to get projects approved were mixed. While 27% expect that it will increase clarity substantially, 20% expect that it will decrease clarity substantially.



What is the Jurisdictional Challenge for the Coastal GasLink Pipeline Project?

The Coastal GasLink (CGL) pipeline project has received provincial approval in BC. CGL is a 650 km pipeline that will transport natural gas from Groundbirch, BC (just west of Dawson Creek) to the proposed LNG Canada Export Terminal near Kitimat, BC.

Smithers BC resident Mike Sawyer and Ecojustice have submitted arguments to the National Energy Board (NEB) that the Coastal GasLink pipeline project is a "federal undertaking" and therefore should be federally regulated. The NEB is expected to make a decision regarding the jurisdiction of the CGL pipeline project in the next several months.



9

Induced Seismicity Monitoring

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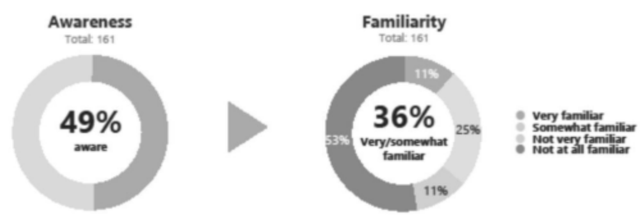
Just over one-third (36%) of stakeholders indicated that they are at least somewhat familiar with the Induced Seismicity Monitoring Special Order.

Just under seven-in-ten stakeholders (69%) indicated that they expect the special order will increase the financial costs to meet regulatory requirements, with most of these (48%) expecting that financial costs will increase somewhat.

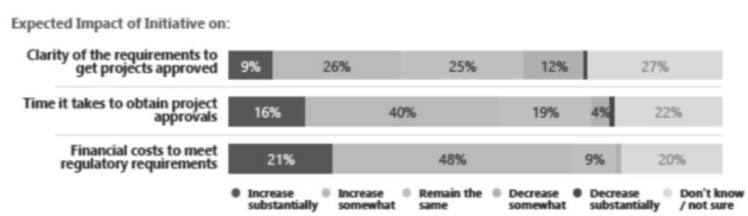
Over half of stakeholders (56%) expect that the special order will increase the time it takes to get project approvals – with most of these (40%) expecting that project approval times will increase somewhat.

Overall, 35% of stakeholders expect that the special order will increase the clarity of the requirements to get projects approved. However, a substantial percentage (27%) indicated that they were not sure how the special order would impact the clarity of the requirements to get projects approved.



What is the Induced Seismicity Monitoring Special Order?

The BCOGC issued a Special Project Order requiring permit holders of any well wholly or partially located within the Kiskatinaw Seismic Monitoring and Mitigation Area to conduct seismic hazard pre-assessments as well as community engagement within the order area. The Order was issued to address a series of low-level seismic events arising from hydraulic fracturing in a ground motion monitoring area in the order area.



10

Professional Governance Act

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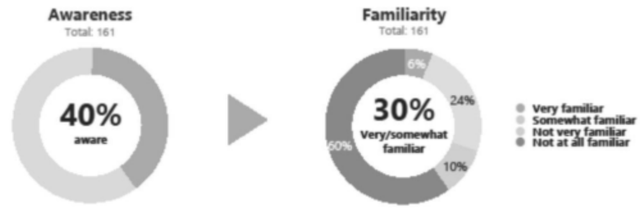
Just under one-third (30%) of stakeholders indicated that they are at least somewhat familiar with the Professional Governance Act.

Just over half of stakeholders (53%) indicated that they expect the Professional Governance Act will increase the financial costs to meet regulatory requirements, with most of these (38%) expecting that financial costs will increase somewhat.

Four-in-ten stakeholders (40%) expect that the Act will increase the time it takes to get project approvals – with most of these (29%) expecting that project approval times will increase somewhat.

Just under one-third (31%) of stakeholders expect that the Act will increase the quality of the work performed by professionals governed under the Act. Most commonly, however, stakeholders expect that the quality of work will not be impacted – almost half (48%) of stakeholders expect the quality of work to remain the same.

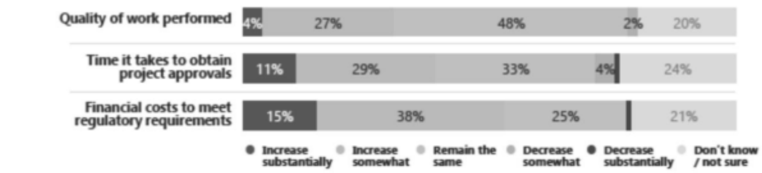


What is the Professional Governance Act?

Through the Professional Governance Act, the BC Government has established the Office of Professional Regulation and Oversight. The intent of the Office is to oversee professional legislation, develop best practices for governance, and regulate the following professional organizations:

- Applied Science Technologists & Technicians of BC
- College of Applied Biology
- Association of BC Forest Professionals
- Engineers and Geoscientists of BC
- BC Institute of Agrologists

Expected Impact of Initiative on:



11

Noise Management Requirements

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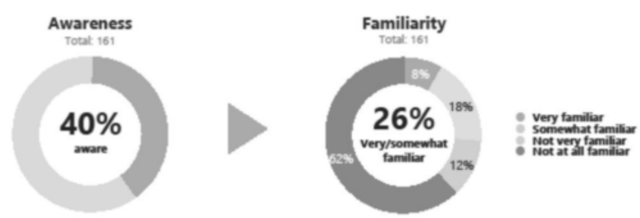
Just over one-quarter (26%) of stakeholders indicated that they are at least somewhat familiar with the Noise Management Requirements.

Two-thirds of stakeholders (67%) indicated that they expect the requirements will increase the financial costs to meet regulatory requirements, with most of these (45%) expecting that financial costs will increase somewhat.

Just under half of stakeholders (49%) expect that the requirements will increase the time it takes to get project approvals – with most of these (37%) expecting that project approval times will increase somewhat.

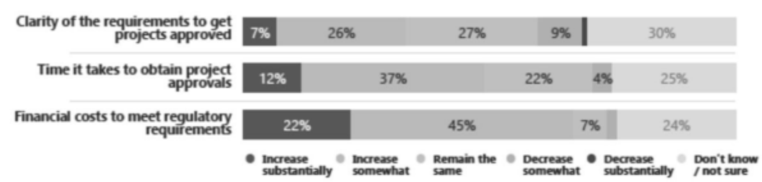
One-third of stakeholders (33%) expect that the requirements will increase the clarity of the requirements to get projects approved, with most of these (26%) expecting clarity to increase somewhat.



What are the Noise Management Requirements?

The noise management requirements are intended to ensure that when drilling and completion activities are conducted within the Farmington Development Area (FDA), industry provide impacted residents with information on the source of the noise, the likely noise levels, and the likely duration of the noise. Industry is also required to develop an overarching program for noise management which specifies when site-specific noise mitigation plans are required.

Expected Impact of Initiative on:



12

Overall Effectiveness of BCOGC

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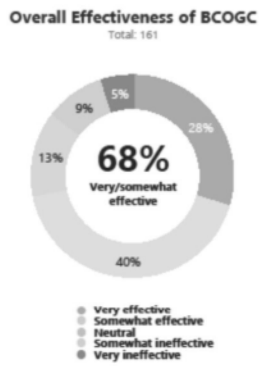
Stakeholders were asked to rate the overall effectiveness of the BC Oil and Gas Commission when it comes to regulating upstream oil and gas activities in BC.

Just over two-thirds of stakeholders (68%) indicated that the BCOGC is doing an effective job in regulating upstream activities in BC – with over one-quarter (28%) it is doing a very effective job.

Only 14% of stakeholders indicated that they feel the BCOGC is not doing an effective job in regulating upstream activities.



13

Expected Overall Impact of Regulatory Changes

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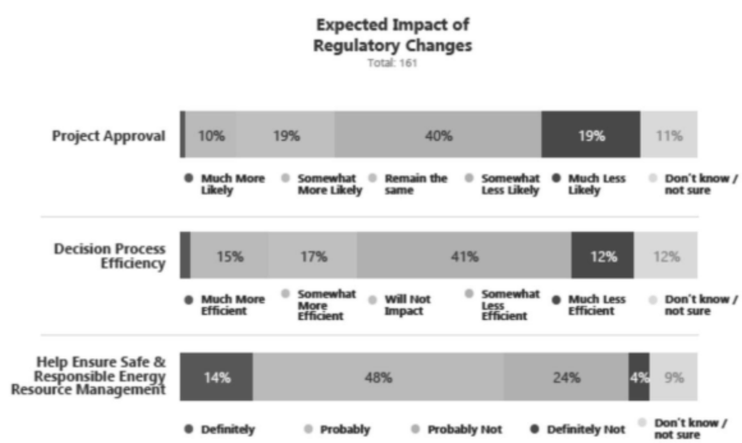
Stakeholders were asked to rate the impact that they expect the regulatory changes, taken together, will have in three areas:

- The likelihood that major resource projects will be approved in BC
- The efficiency of with which BCOGC will conduct the project decision process
- Helping ensure the safe and responsible management of energy resources in BC

A relatively strong majority of stakeholders (62%) believe that the regulatory changes will either probably (48%) or definitely (14%) help ensure safe and responsible energy resource management in BC.

However, over half of stakeholders believe that the BCOGC's decision process will become less efficient (53%), and over half believe that the regulatory changes will make major resource project approvals less likely (59%).



14

Main Business Activity of Organization and Stakeholder Role

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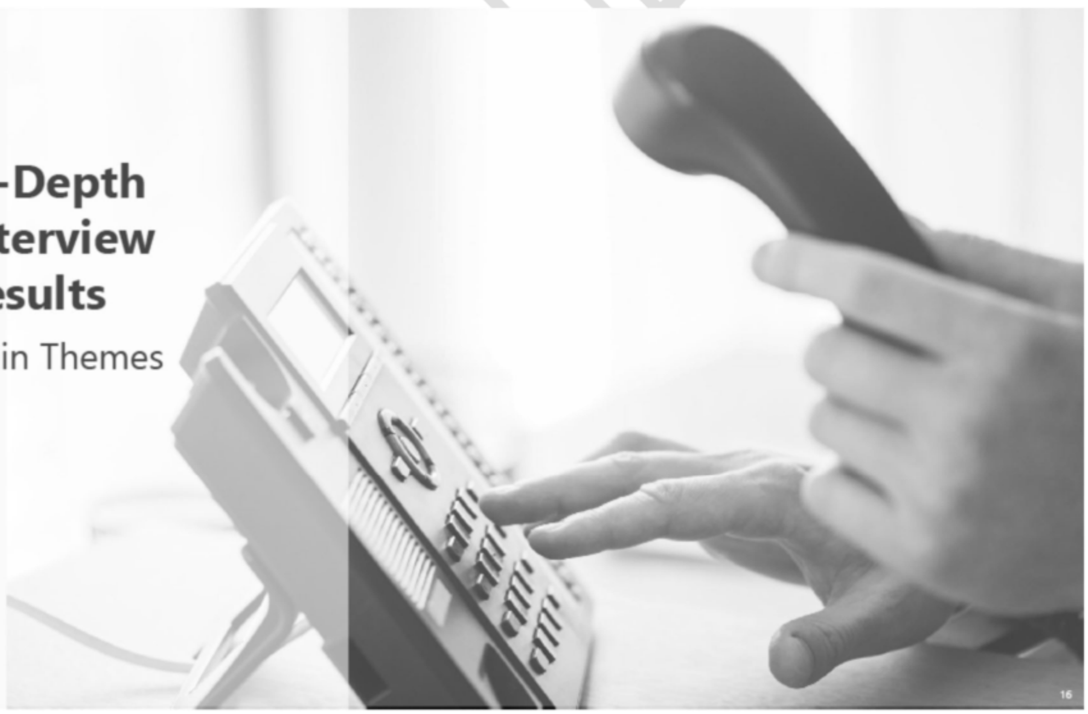
Organization's Main Business Activity	Total*
(base)	161
Energy Exploration and / or Production	47%
Regulatory Compliance	20%
Environmental Consulting	14%
Stakeholder Engagement	11%
Land Surveying / Mapping Services	11%
Engineering Consultants / Contractors	9%
Energy Transmission and / or Storage	8%
Emergency Response Planning	7%
Resource Disposal Services / Waste Management	7%
Data and Analytics	5%
Management Consulting	4%
Industry Association	2%
Geoscience Consultants / Contractors	2%
Other	2%

*Percentages will add to more than 100% given survey participants could select more than one business activity.

Role/ Area of Responsibility	Total
(base)	161
Regulatory Compliance	20%
Environmental Assessment / Advising	12%
Engineering	11%
Operations / Facilities Management	10%
Land Surveying / Mapping / GIS	9%
Project Management	7%
Health & Safety	7%
Land Agent	6%
Government Relations	4%
Stakeholder / External Relations	3%
Geoscience	3%
Emergency Response Planning	3%
Technologist	1%
Communications	1%
Business Analysis	1%
Investor Relations	0%
Other	1%

In-Depth Interview Results

Main Themes



Main Themes from the In-Depth Interviews

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The sheer volume of regulations and proposed initiatives - and the pace with which they are being issued – is placing strain on the industry in a variety of ways. Given that many companies have had to downsize due to the slowdown in the industry, companies have fewer human resources to devote to understanding the regulations and what their impacts might be. Also, the volume and pace of initiatives is increasing uncertainty, which is reducing investor confidence.

The BCOGC is generally viewed as open to new ways of thinking, transparent and very accessible to the industry. This is a clear differentiator of the BCOGC compared to other regulators. However, with the recent increase in regulatory activity, there is some concern that the BCOGC is not giving the industry enough time to provide feedback before orders are issued. This makes the BCOGC appear more prescriptive than it has in the past.

While there is recognition that there is value in a regulator being prescriptive, there is a strong belief that maintaining a focus on outcomes – i.e., the goals that the regulation is intended to achieve – will allow operators to achieve high standards of safety and environmental protection in a more efficient manner. Operators feel that having the regulator prescribe *what* the regulation is intended to achieve but allowing the operator leeway in *how* it achieves the intended outcome, will enable responsible resource development.

Maintaining a focus on outcomes is also seen as a way to minimize the unintended consequences of regulations. Interviewees mentioned a range of unintended consequences, including setting unattainable compliance targets, making it less financially attractive to purchase existing BC oil and natural gas assets, reducing the incentive to invest in new technology, and increasing the risk of negative environmental impacts, among others.

While there are some challenges at the agency level, duplication is generally not perceived to be problematic within regulatory agencies. Duplication is more of a challenge when organizations are trying to comply with regulations and reporting requirements that can be different between the federal regulator and a provincial regulator, and between provincial regulators.

Industry wants there to be greater recognition of the cumulative impact of regulator requirements. While one regulation may not, in and of itself, have a significant impact on a company's operation and financial health, the combined impact of successive regulations is significant.

17

Main Themes from the In-Depth Interviews

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Industry noted that several BC government initiatives that have yet to be operationalized into regulations are creating significant levels of uncertainty for the industry. They anticipate that these initiatives will have a regulatory impact. However, the larger concern is that industry doesn't know what the impact will be, or when industry will be required to adapt.

One initiative is the **Environmental Assessment Revitalization Process**. It was acknowledged that this is not an OGC measure, but that it could infringe on OGC's one-window approach - an approach highly valued by industry. This is because operators expect that they will have to wait for a decision on the same project from two different groups. Specifically, operators expect that they will have to go through the BCOGC to get their project permit, and then have to undergo a separate process to justify the project, but with a different group (the EAO) making the decision. This is expected to increase approval times as well as decrease the certainty that projects will be approved. Also creating uncertainty is that operators don't know what criteria will be used to assess projects or who the decision-making authority is.

Another initiative is the **United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP)**. Industry sees UNDRIP as vast in scope, with language that makes it difficult to conceive of how the articles in UNDRIP will be operationalized in the regulatory system. For example, referring to Article 32 in UNDRIP, one industry representative asked "What does it mean to seek informed consent from indigenous groups prior to the approval of any project affecting their land?" Industry expects that operationalizing UNDRIP into regulations could result in very protracted regulatory review timelines.

18