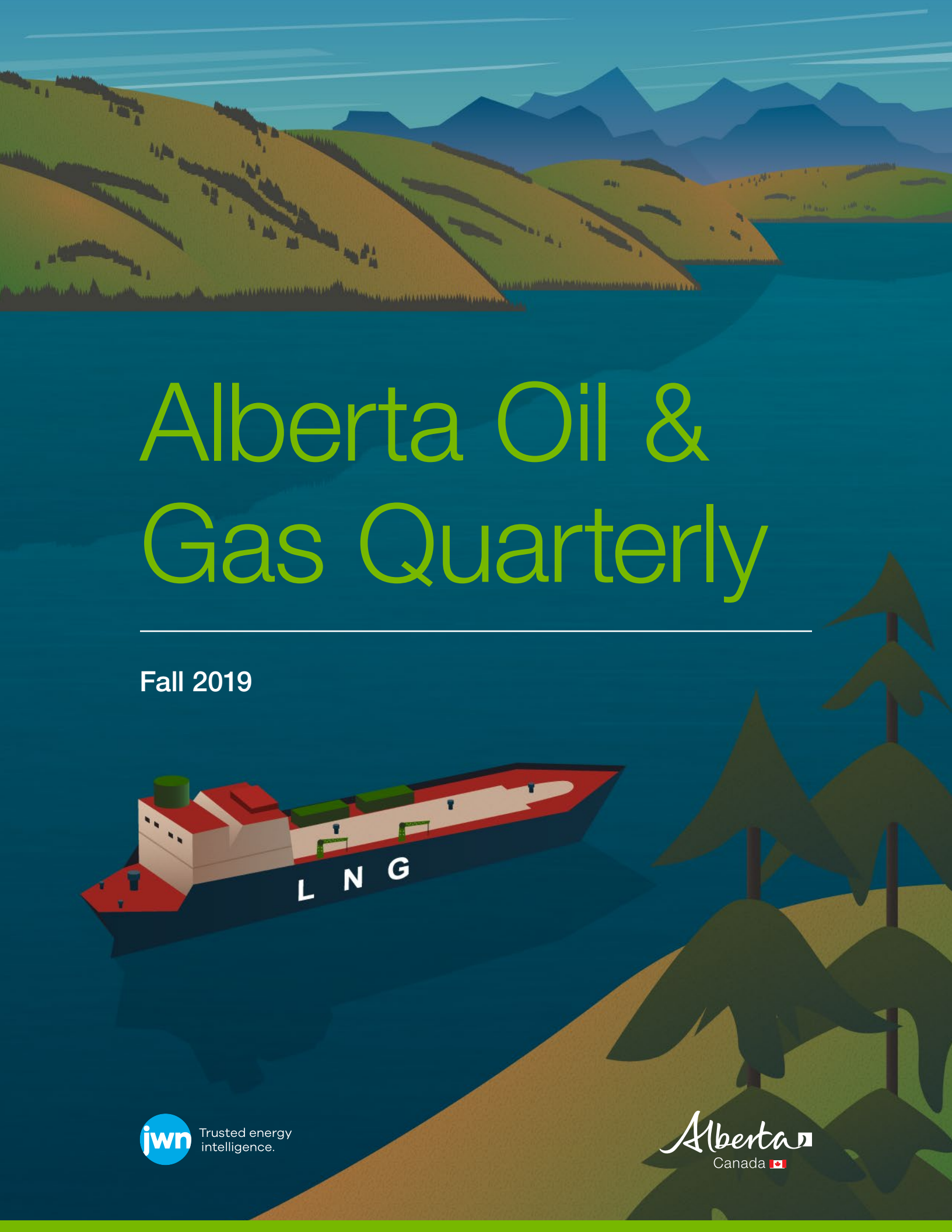




Alberta Oil & Gas Quarterly

Fall 2019



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On the cover: Illustration of an LNG carrier along the coast of British Columbia.

Image: Samantha Fung/JWN.

Unless otherwise stated, photos ©JWN 2019.

Content prepared by JWN for the Government of Alberta.

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NEXT ISSUE

Midstream: Inside Alberta's expanding oil and gas processing and transportation sector

LNG: Charting a new course for Western Canada's gas

Canada may be the world's fifth-largest natural gas producer and amongst its largest reserve holders, but that has never guaranteed it will be able to capitalize on the growing global trade of LNG.

BP's latest energy outlook forecasts that LNG volumes shipped around the world will more than double in the coming years, from approximately 14 trillion cubic feet in 2017 to almost 31 trillion cubic feet in 2040.

Demand growth in Asia and Europe is expected to increase as countries pursue alternatives to diesel and coal to support cleaner electricity generation, heating, and transportation requirements.

Analysts have a "reasonably positive outlook" for LNG development in Canada, but that wasn't always the case, Wood Mackenzie's Alex Munton said in an August webinar.

"There was a period when we wondered whether we would ever see LNG happen in Canada," he said. "The key was to drive down costs."

A decade ago, there were more than 20 LNG export projects proposed for Canada's West Coast, but most developers dropped plans due to capital cost concerns, market uncertainty and a surge of LNG growth from the United States and Australia.



The positive final investment decision on the \$40-billion LNG Canada project in Kitimat, B.C. in October 2018 was a turning point, Munton said.

The project moved ahead in part thanks to government tax concessions, but key to the commercial decision was the ability of the Royal Dutch Shell-led joint venture to drive down capital costs, he said. The relative remoteness of the project made it “very expensive” to develop.

But LNG terminals on the B.C. coast have natural advantages over projects on the U.S. Gulf Coast, for example, including abundant underpriced natural gas resources and closer proximity to Asian markets.

Together, Alberta and British Columbia currently produce about 15.5 bcf/d of natural gas, according to data from the Canadian Energy Regulator.

LNG Canada’s first two trains are designed to process approximately 1.7 bcf/d into 13 mtpa of LNG for export by 2025, providing desperately needed relief to the oversupplied natural gas market in Western Canada. >>

Cover Feature

LNG Project Status: Western Canada

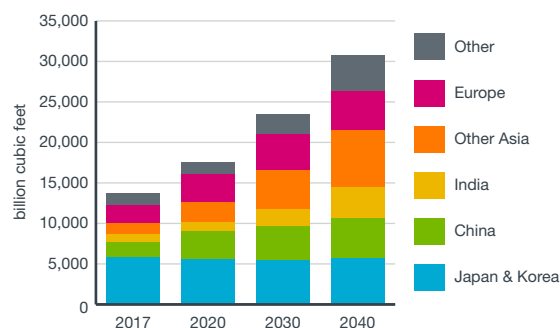
Project	Owner(s)	Capacity (mtpa/bcf/d)	Capital Cost (billions)	Status
LNG Canada	Shell, PETRONAS, PetroChina, Mitsubishi Corporation, KOGAS	13-26/1.7-3.4	\$40	Under construction; completion expected by 2025
Kitimat LNG	Chevron, Woodside Energy	10/1.3	N/A	Chevron has applied to nearly double project capacity; completion expected by 2029
Woodfibre LNG	Pacific Oil & Gas	2.1/0.3	\$1.8	Final investment decision expected in 2019; completion in 2023

LNG Project Status: Eastern Canada

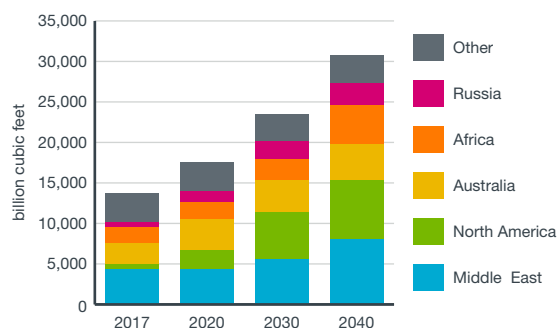
Project	Owner(s)	Capacity (mtpa/bcf/d)	Capital Cost (billions)	Status
Goldboro LNG (Nova Scotia)	Pieridae Energy	5-10/0.7-1.3	\$10	Final investment decision expected in 2020, completion in 2024/2025
Bear Head LNG (Nova Scotia)	LNG Limited	8-12/1.1-1.6	\$6	
Énergie Saguenay (Quebec)	GNL Quebec	11/1.5	\$9	Final investment decision expected in 2020; completion in 2025

*Only projects with export licenses and regulatory approvals in place are included.
Source: Canadian Energy Research Institute, company announcements

Global LNG Supply and Demand Forecast - Imports



Global LNG Supply and Demand Forecast - Exports



Source: BP Global Energy Outlook 2019

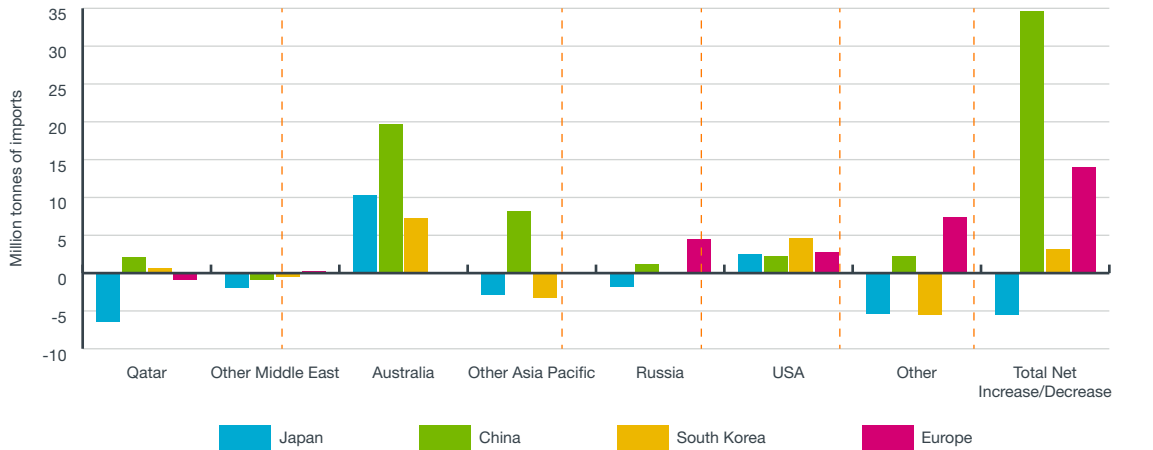
LNG Data

Competitive Marketplace: Selected non-Canadian LNG projects planned on-stream before 2030

Project	Country	Planned Capacity (mtpa)	Planned start date
Qatargas Expansion	Qatar	32	2024
Rio Grande	USA	27	2023
Driftwood	USA	26	Mid-2020s
Plaquemines	USA	20	2023
Arctic LNG 2	Russia	19.8	2023
Delta LNG	USA	19.8	2023
Lake Charles	USA	16.45	2025
Golden Pass	USA	15.6	2024
Rovuma LNG	Mozambique	15.2	2025
Port Arthur	USA	13.46	Mid-2020s
Delfin LNG	USA	13	Early-2020s
Mozambique LNG	Mozambique	12.88	2024
Calcasieu Pass	USA	10	2022
Abadi LNG	Indonesia	9.5	2025-2030
Magnolia LNG	USA	8.8	Mid-2020s
Annova LNG	USA	6	2024
Coral South FLNG	Mozambique	3.3	2022
Greater Tortue	Mauritania/Senegal	2.5	Early-2020s

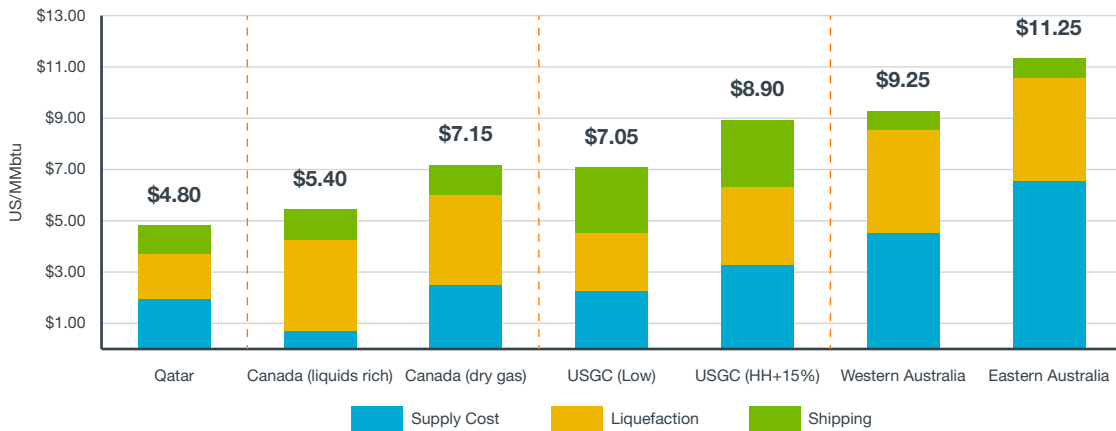
Source: Evaluate Energy

Major Markets For Canada: Change in imports by origin, 2013 - 2018



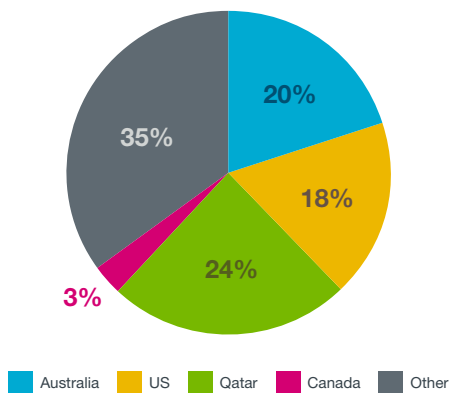
Source: GIIGNL

LNG Cost of Supply

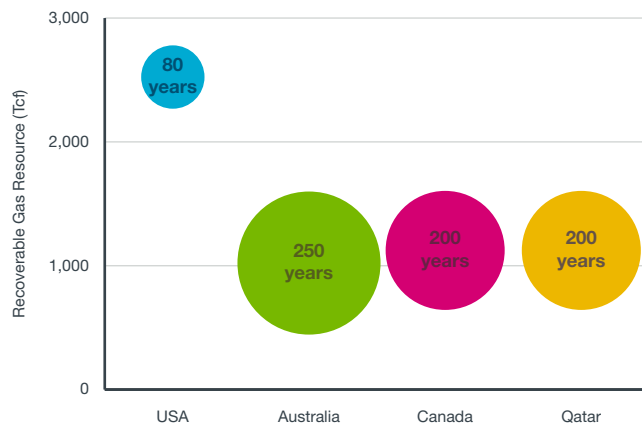


Source: Sproule Play Metrics, Oxford IES, Rystad, Sproule Estimates

2025 Global LNG Export Market Share by Country



Who has the Rock to Supply the Gas?



Source: Sproule, IGU, EIA, NEB, Qatar Petroleum, Australian Government, BP

Bringing stability to an industry in turmoil



Q&A with Dale Nally

Alberta's Associate Minister of Natural Gas

This spring's election saw the election of a new government in Alberta, along with the appointment of Alberta's first-ever Associate Minister of Natural Gas. It's a positive sign that the province intends to focus on an important sector that has faced significant challenges over recent years. Dale Nally, MLA for Morinville-St. Albert, holds the key government role, supported by the Department of Energy.

Why is it important for the Government of Alberta to focus on the natural gas industry?

We have a natural gas industry that is in absolute turmoil. We have natural gas producers on the brink of bankruptcy, and we have natural resource owners – that's Albertans – who are not being adequately compensated for their resources.

We're talking about an industry that used to generate over \$8 billion in royalties to the province that is currently generating a little less than \$500 million. We need to bring some focus and stability to this important industry so that we can bring prosperity back to Alberta.

What is your top priority area?

My first priority is going to be bringing stability to the industry. That starts with the Natural Gas Advisory Panel's Roadmap to Recovery report; there were 48 recommendations in there and we are working through those as diligently as possible to bring as many of those to fruition as we can.

For example, we worked with industry to support a change to the storage protocol on our pipelines that will allow our producers to access storage during periods of maintenance. This will help with the volatility, because right now if natural gas is trading at \$2 it's collapsing down to 10 cents often because of the storage protocol that's currently in place.

We're very happy that the Canadian Energy Regulator recently approved this change, which will be very substantial in bringing some stability to the AECO price.

How is Alberta working with British Columbia to advance LNG exports, given that the two provinces are at odds over oil transportation?

Obviously we do not see eye to eye on TMX, but when it comes to LNG we have a long history of agreement and collaboration with the British Columbia government. We have been working and will continue to work together at the administrative level on shared priorities for our two governments. Although I have not yet met with Minister Mungall, I could foresee this happening in the very near future because (LNG) is of great importance to both of our provinces.

What is Alberta doing to optimize the regulatory environment for natural gas producers?

In September, Energy Minister Sonya Savage announced a review of the Alberta Energy Regulator, along with the appointment of a new interim board. We're not looking for the Wild West here, but we need to make sure the province's resources are being developed efficiently and in an environmentally responsible manner.

We anticipate this review will identify enhancements to the AER and ensure that Alberta remains a predictable place to invest and a world leader in responsible energy development. We've also got the Ministry of Red Tape Reduction that will be looking to reduce more than 30 percent of the red tape in this province, and that includes the energy industry. That is going to go a long way in shortening approvals.

Will Alberta continue to invest in projects such as petrochemical facilities to diversify markets for natural gas?

We made it clear in our election platform that this government is committed to diversifying our economy.

That includes investments in petrochemicals, and we have been vocal in saying we will continue to support this sector where it makes sense.

How is Alberta building Indigenous participation in natural gas projects?

The Premier made it very clear from day one that this government is going to be an ally of Indigenous peoples. One of the very first things that he did was host a meeting between the 48 First Nations chiefs and cabinet.

We're also in the process of creating the Alberta Indigenous Opportunities Corporation, which is going to backstop up to \$1 billion in loans in the energy business for Indigenous companies, and it's probably the single biggest thing this government can do for reconciliation right now.

How will you measure your success as Alberta's Associate Minister of Natural Gas?

I'll know that I've been successful when natural gas producers are turning a reasonable profit, when resource owners are being adequately compensated for their resources, and lastly, when Alberta contributes in a meaningful and substantial way to global emissions reductions by getting LNG to India and China.

I want to send the message that Alberta is absolutely open for business. We are reducing red tape, which is going to make it easier and friendlier for energy companies to do business in this province; we have reduced corporate taxes to encourage investment, and we are very optimistic about the future.

Canada's LNG carbon footprint: Better than best in class



LNG from Western Canada is expected to have among the lowest GHG profiles in the world, layering another competitive advantage on top of fast shipping times to Asia.

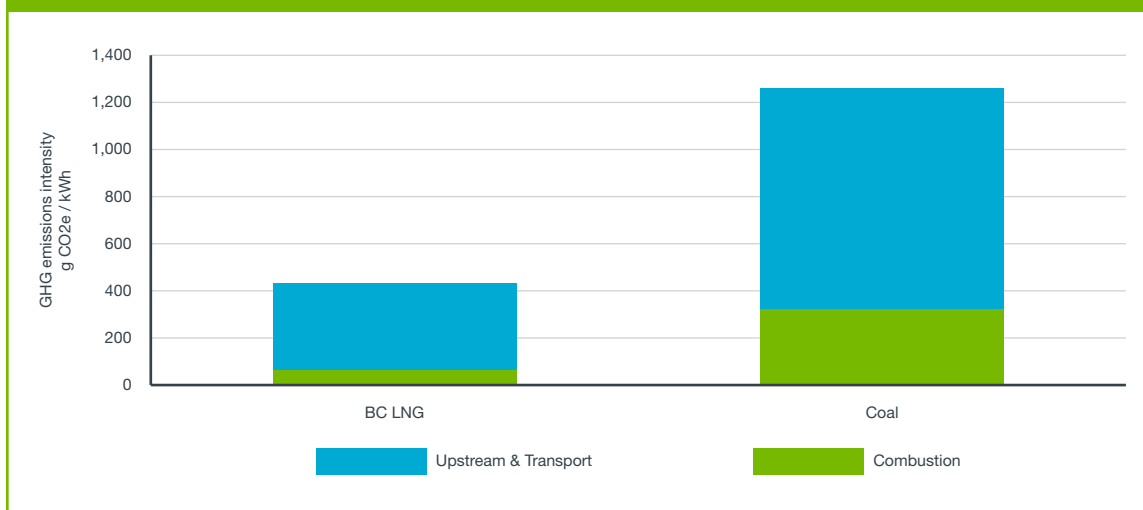
Right out of the gate with the first major project, Canadian LNG operations will be well below the global emissions average of 0.26 to 0.35 tonnes of CO₂ equivalent per tonne of LNG produced. LNG Canada, currently under construction at Kitimat, B.C., is being designed for 0.15 tonnes of CO₂ equivalent per tonne per tonne of LNG.

The two projects that may follow over the next decade – Woodfibre LNG and Kitimat LNG – are designed for intensity of approximately 0.06 to 0.08 tonnes of CO₂ equivalent per tonne of LNG.

“Liquefied natural gas from B.C will have the least CO₂ per tonne of any LNG produced in the world,” said Bryan Cox, CEO of the BC LNG Alliance.

“Not only will B.C. projects have the potential to reduce global emissions by displacing coal, they will also reduce global emissions if they

Canadian LNG: 65% less carbon intense than coal for electricity



Source: CAPP, industry analysis with data from B.C. government, B.C. LNG Alliance, EIA, US Department of Energy, International Gas Union

replace LNG produced in other jurisdictions.”

LNG Canada says its low GHG footprint will be achieved through a combination of the lower-CO₂ composition of Montney natural gas; widespread electrification of upstream operations like drilling and processing; the use of green power from B.C.’s hydro-driven electrical grid; and use of highly efficient gas turbines at the liquefaction plant.

“A B.C. LNG facility that uses gas-powered turbines will produce literally millions of tonnes less CO₂ during its life cycle than a Gulf Coast plant of similar size,” Cox said.

Both the Woodfibre LNG and Kitimat LNG projects plan to take it one step further by using electric-drive technology versus gas-fired turbines for liquefaction.

Since the power produced in B.C. is 98 percent clean energy, mostly from hydro power, electric drive will be “orders of magnitude” lower in emissions intensity of the large LNG plants either built or proposed for the U.S. Gulf Coast, said Fred Eastwood,

commercial manager for the Kitimat LNG project with Chevron Canada.

“With the use of hydro power, our greenhouse gas footprint is five to eight times lower than best-in-class,” he said.

Projects in Western Canada also have fewer emissions associated with transporting the LNG to Asia, since the travel time from B.C. is just 10 days – about half the time it takes for LNG carriers to travel from the Gulf Coast to Asia.

“The greenhouse gas footprint, and the fuel loss through the value chain, is orders of magnitude lower than the Gulf Coast,” Eastwood said.

Electric-drive technology “would substantially reduce, but not completely eliminate, greenhouse gas emissions from the LNG facility at Kitimat,” said David Austin, a lawyer specializing in energy at Stirling Law.

“From this perspective it’s very good news. But like all LNG projects, the proof will be whether it’s ever built.”

Consortium of Alberta natural gas producers developing own LNG project



Q&A with Greg Kist

CEO, Rockies LNG Partners

Image: CP Images

A group of nine mid-sized Alberta natural gas producers have formed a coalition to advance an LNG project on Canada's West Coast. The companies compete for land and opportunities, but recognize that they need to work together to get an export project off the ground, says Greg Kist, CEO of the consortium, called Rockies LNG Partners.

Why does it make sense for producers to work together to develop LNG opportunities?

When you look at having to build a large-scale pipeline out to the West Coast and a large-scale facility, you need size and scale in terms of supply. The current producer group produces about 3 billion cubic feet per day, so they've got a very large, long-term supply base that can be very attractive to LNG buyers.

That's why it's important for producers to work together, whereas for a single mid-cap producer in Western Canada it would be extremely difficult for them to do anything even remotely like this on their own. One of the things that we're looking at is bringing in partners in both the pipeline and for the terminal itself; players that are obviously more infrastructure-type parties.

Does the consortium plan to revive a mothballed LNG project?

We're not trying to resurrect an old project, but what we're trying to do is to make sure that we don't lose the benefits of things that have already happened.

I would use as an example that the two pipelines that we're considering out to the West Coast already have environmental certificates and have done a certain amount of the permitting: that being TC Energy's Prince Rupert Gas Transmission Pipeline and Enbridge's West Coast Connector Pipeline.

What impact does the new federal environmental review process under Bill C-69 have on the consortium's plans?

It's hard to know obviously because it is so new, but we've had a chance to begin to assess what the requirements of the new regulations are and I think we certainly see a path through that.

There's certainly a series of unknowns, but that's also why we would say at this stage that we don't want to stray far from the existing approved pipelines.

As far as the terminal goes, it's yet to be

Cover Feature

seen whether it would ultimately be under a federal regulatory process or whether it would be under a provincial regulatory process, so that's to be assessed, but I think both for British Columbia and for federal regulations, we've had a chance to have a look at them and we think we have a path to navigate through that.

It will certainly be intense, as regulatory processes should be as it relates to the environment, but certainly we have better visibility now than say six months ago.

What is the current status of the consortium's efforts?

We're working very hard to determine if there are customers that are prepared to work with us to try to advance a project. We have several very interested parties in terms of being the buyers of the LNG ultimately.

We're really targeting coming on-stream

some time later in the 2026-type timeframe, so if you kind of work everything back from there you kind of need to get kicked off in the first phases of any new regulatory process arguably in the next six months.

We've already done a significant amount of work: we've completed a Class 4 engineering estimate; we've been working very hard with the pipeline companies to determine what the best opportunity is; we've already done a significant amount of work on project descriptions so that we're ready to go once we've ultimately selected the site; and our engagement with Indigenous nations has been ongoing from the very start.

In fact, the very first thing that I did when I joined the group is I let the group know that I wasn't interested in trying to find a site as much as I was interested in speaking with the Indigenous nations to see what is the most appropriate site from their perspective, so we're in the throws of trying to nail that down.

Rockies LNG Partners:

The view from Marty Proctor, CEO, Seven Generations Energy

Why is Seven Generations involved in Rockies LNG Partners, and how do you expect to benefit from LNG access?

Egress has been core to our strategy and as we evolved our understanding of how prolific the Montney resource was, we felt that it was imperative to ensure adequate takeaway capacity out of the basin. This approach has created meaningful options for transporting our natural gas into key consumer markets and has driven significantly higher realizations for our gas prices compared to local AECO pricing.

As we think about egress into the next decade, we see LNG being a key outlet

for natural gas in the WCSB that will help diversify consumer markets and ultimately bring domestic prices closer in line with global natural gas prices. Given the importance of LNG, we feel the best opportunity to participate is to partner with like-minded producers to aggregate meaningful volumes.

We expect LNG access will support higher prices for the basin, or prices that are more closely linked to global natural gas prices. Ultimately sales prices will be based on the market clearing price, less transportation and shipping and the liquefaction/re-gasification tolls.

Domestic LNG: Remote communities, mines the first to benefit

Canada's emerging LNG export industry should also bolster the domestic market supplying remote communities and industrial operations in need of reliable energy, says Allan Fogwill, CEO of the Canadian Energy Research Institute (CERI).

Put simply, with more LNG production facilities, there will be more LNG available to supply markets both within Canada and overseas.

Domestic LNG is most applicable in "off the grid" scenarios such as replacing diesel-fired electricity in Northern Canada and remote coastal communities, Fogwill says. While liquefaction capacity is costly and LNG cannot compete with pipelined gas in many contexts, it is valuable for certain applications.

"In areas where there's the possibility of changing out the electricity generation for remote grids, as in the North, it's starting to be used there," he says, adding that the mining sector offers the biggest opportunity for the domestic LNG market due to the costs associated with providing power to new mines in remote locations.

While current domestic LNG production might be somewhat limited, notes Fogwill, there are Canadian facilities serving customers with liquefied gas.

In 2014, Ferus Natural Gas Fuels Inc. opened Canada's first merchant LNG facility at Elmworth, Alta., which is 65 kilometres southwest of Grand Prairie. FortisBC has two LNG facilities on the West Coast of B.C., including Ladysmith's Mt. Hayes LNG, built in 2011, and Delta's Tilbury Island LNG, built in 1971.

Formerly known as Gaz Métro, Québec natural gas distributor Énergir has a liquefaction plant in Montréal, while Enbridge Gas Inc. has expressed interest in selling LNG at its Hagar plant between North Bay and Sudbury, Ont.

The ideal situation for domestic LNG usage would be a mine in proximity to a Northern community, Fogwill says, with all stakeholders working together to install and support the necessary infrastructure. That way, there is reliable power for the life of the mine, and the community has access to that power even longer.

"It gives the LNG asset another customer, if you will," he says. "This could be a way of getting some residual value out of it for the mine and selling it to the community, or operating it jointly."

While LNG can power freighting operations, and there have been associated pilot projects across the country, Fogwill says there are limits in terms of replacing diesel with LNG for the trucking industry.

"It's still a challenge because it reduces optionality," he says, adding most trucks that run on LNG are converted from diesel, which costs money and impedes vehicle performance. There may be niche applications for LNG for trucking, but Fogwill expects other technologies – like hydrogen fuel cells – will replace diesel in this segment first.

News

Sessions to boost Indigenous engagement in midstream, downstream projects

InnoTech Alberta is hosting a series of sessions this fall and winter to bring more Indigenous-owned companies into opportunities in midstream and downstream oil and gas.

While many Indigenous companies have found success working in the upstream sector, there is room for growth in midstream projects like natural gas and natural gas liquids processing, pipelines and rail, says Peter Krzesinski, InnoTech Alberta's program lead.

"When people think about the oil and gas industry, they think about drilling and exploration but a lot of people skip over the midstream and downstream side. Within the Indigenous supplier world we're trying to raise awareness of the opportunities outside of the upstream sector," he says.

"In the last five years or so the investment has shifted

from the upstream sector from oil in particular and oilsands even more so into the midstream and downstream sector, [such as] gaining more value out of natural gas and natural gas liquids. The events are being held in the spirit of reconciliation through economic engagement of the Indigenous people."

Indigenous-owned Pimee Well Servicing LP has been operating since 1984, primarily in upstream heavy oil. The company is looking for diversification opportunities, says industry relations/business development officer Sandy Jackson.

He attended the first InnoTech Alberta event, held in Calgary in late September, and found the setup and smaller scale (approximately 80 attendees) to be helpful for companies looking for more information about contracting opportunities.

"It was very beneficial because it allowed networking and one-on-ones amongst the companies and Indigenous leaders and businesses," Jackson said, adding that level of dialogue is not always possible at larger events.

"What we're finding is there are opportunities where there could be cooperative efforts with other Indigenous companies, or even non-Indigenous companies; a willingness to look at joining forces."

InnoTech Alberta's engagement sessions are being conducted with support of the Ministry of Economic Development, Trade, and Tourism. The initiative capitalizes on investment within the midstream and downstream oil and gas sector, in part created by the provincial government's petrochemical diversification program.



Construction at the Heartland Petrochemical Complex in September 2019.

Three sessions are bringing together over 50 Alberta-based Indigenous suppliers with 25 large Alberta midstream and downstream oil and gas sector purchasers including major operators, engineering, procurement and construction firms, and construction contractors.

Members of procurement and Indigenous relations teams from a variety of

major purchasers within the midstream and downstream oil and gas sectors will provide presentations on procurement practices, skills/qualifications/ services requirements, as well as major upcoming infrastructure projects.

Participating Indigenous companies will have the opportunity to meet one-on-one with the purchasers

over the course of the events, Krzesinski says.

The first sold-out session was held September 24-25 at the Gray Eagle Resort in Calgary. A second sold-out session is planned for November 12-13 at the River Cree Resort and Casino in Edmonton, and a third event is planned in February 2020 at a location to be determined.

For more information, contact Dr. Shauna-Lee Chai, Indigenous relations lead and senior research scientist with InnoTech Alberta, at shauna-lee.chai@InnoTechAlberta.ca.

Upstream News

Oil Production

► Total Canadian oil production grew by 50,000 bbls/d in July to surpass 5.5 million bbls/d, according to a report from the International Energy Agency.

A 100,000-bbl/d increase in synthetic crude oil was partially offset by a fall in raw bitumen and offshore production, the IEA said.

“Alberta’s upgraders produced 1.25 million bbls/d in July, 235,000 bbls/d more than a year earlier. In contrast, un-upgraded supply fell by 60,000 bbls/d month over month, to 1.77 million bbls/d, 125,000 bbls/d less than a year ago,” the IEA said.

Despite Alberta’s ongoing oil curtailment, the IEA expects total Canadian production to increase by 95,000 bbls/d on average this year and a further 100,000 bbls/d next year, when output reaches 5.6 million bbls/d.

Major Capital Projects

► Suncor Energy Inc. is going ahead with a major capital project at its oilsands Base Plant that is expected to increase profits while reducing environmental impacts.

The company has given the green light to a \$1.4 billion investment that will replace aging coke-fired boilers at the facility with natural gas-fired units, generating process steam and enabling the export of approximately 800 MW of power for sale into the Alberta grid, or about eight per cent of the province’s electricity demand.

The new cogen units are expected to be in service in the second half of 2023.

► The Government of Alberta has issued approval for MEG Energy Corp. to build a 120,000-bbl/d phased new SAGD project, called Surmont, located nearby

its existing Christina Lake facility.

While MEG continues to work on development plans for Surmont, Christina Lake is the company’s focus at this time, said spokeswoman Tara McCool.

In mid-2018 MEG commenced work on a 13,000-bbl/d brownfield expansion at the project, but in July it cancelled plans for any capital spending on it this year amid Alberta’s ongoing curtailment and pipeline delays.

Land

► The Alberta government’s August land sale brought \$12.55 million into government coffers, the highest amount at a single auction this year.

Industry picked up 53,376 hectares at an average price of \$235.03. Year-to-date, the province has collected \$94.4 million, down 63 per cent over the same period of 2018.



Image: Encana

The number of hectares sold has declined by 34 per cent to 552,309, while the average price has plunged 44 per cent to \$170.93.

Drilling

► Natural gas and liquids producer Birchcliff Energy is going against the industry trend and increasing its capital program for 2019.

With strong Q2 results, including encouraging performance of new wells in the Montney play, Birchcliff announced that it will increase spending by approximately 19 percent.

The company now plans to spend \$242 million on exploration and development, up by \$38 million compared to previous guidance.

That will provide for drilling of an additional seven net horizontal wells, which are expected to be onstream by November 1, 2019.

The company has increased its production guidance for the year to 77,000 to 79,000 boe/d, up from 76,000 to 78,000 boe/d previously.

“Counter to much of the industry, Birchcliff is expanding its E&D capex program,” GMP FirstEnergy analyst Robert J. Fitzmartyn wrote in a research note.

He said the move was “partially telegraphed” by Birchcliff investing 79 percent of its previously announced 2019 capital budget during the first half of the year.

“We think this will be notable for the market, given much of industry moving the other way in the current environment.”

► While the upper zones of the multi-layered Montney formation have been the preferred exploitation targets for companies active in the prolific play, producers are increasingly kicking the tires in the relatively untried Lower Montney zone.

“In most places operators initially worked on the upper part of the Montney because it was quickest and cheapest to access, and worked well. They moved downhole to the Lower Montney only when they wanted to demonstrate resource/reserves additions without greatly expanding land positions,” said Brad Hayes, president of Petrel Robertson Consulting Ltd.

One of those companies is NuVista Energy Ltd., which has focused its program in the Middle and Upper Montney zones but over the last year-and-a-half has begun testing the lower zone, where it has just drilled its fifth well.

“The zone is taking off like the Middle Montney zone was taking off 10 years ago. It’s very, very new and there’s way less wells, but it’s emerging,” said NuVista president and CEO Jonathan Wright.

► Operators rig released 3,292 wells across Canada

to the end of August, down 29 per cent from 4,635 wells drilled in the first eight months of 2018, with the counts off the most in Alberta.

Alberta operators rig released 1,585 wells over the first eight months of 2019, down 36 per cent from 2,466 a year ago, while total metres drilled declined 32 per cent to 5.2 million metres from 7.67 million metres to the end of August last year.

Alberta Natural Gas Demand

► Alberta’s domestic demand for natural gas is expected to accelerate over the next four years as power plants in the province transition off coal, according to analysts with Peters & Co.

“Minimal” coal-fired power is expected in Alberta by 2023, they said.

“Since 2016, ATCO, Capital Power and TransAlta have all announced accelerated timeframes for converting their coal plants to gas-fired generation (with either full conversion or dual-fuel capability) before the end of their useful lives,” Peters & Co. said.

“In total, we calculate approximately 900 mmcf/d of incremental natural gas demand versus today by year-end 2023 from coal-to-gas conversions, with potential upside from further partial conversions not yet sanctioned.”

Midstream News

Pipelines

► A new transcontinental pipeline project similar in concept to the Energy East project is in its formative stages.

It's early on for Canadian Prosperity Pipelines Corporation, but the idea is to transport oil from Hardisty, Alberta, to Saint John, New Brunswick, and a marine tanker terminal for potential export, passing through Saskatchewan, Manitoba, Ontario and Quebec.

The project is targeting oil capacity of 1.1 million bbls/d, with a capital cost estimated at \$23 billion.

► Enbridge says that the 1,070 kilometres of its Line 3 Replacement Project in Canada will go into service by the end of this year.

It's the culmination of four seasons of field construction between Hardisty, Alberta and Gretna, Manitoba, with nearly 50,000 welds and a

peak workforce of 5,300, the company said.

The replacement project is designed to improve safety and increase throughput on Line 3, which was built in the 1960s and is increasingly subject to corrosion and cracking, running at only about half its original capacity for safety reasons.

The full Line 3 Replacement Project includes 13 miles in North Dakota, 337 miles in Minnesota, and 14 miles in Wisconsin. The Wisconsin portion has been operating since May 2018.

Ongoing permitting issues in Minnesota have delayed completion by at least one year, to the second half of 2020.

Analysts with GMP FirstEnergy continue to use a start date of January 1, 2021 in their modelling for the full project, according to a research note this morning.

► Six challenges to the federal government's re-approval of the Trans Mountain pipeline will be allowed to proceed, the Federal Court of Appeal has ruled.

The challenges are limited to the narrow issue of the adequacy of the government's consultation with Indigenous peoples and First Nations between Aug. 30, 2018, and June 18, 2019.

The court has ordered that the challenges proceed on an expedited basis. Short and strict deadlines for the steps in the litigation will be set.

Trans Mountain Corp. is planning to continue construction work on its pipeline expansion project this fall.

The company says that it has received over 55 percent of the total pipe required to build its expansion project, or 550 kilometres of the 1,000-kilometre total. The pipe, primarily produced by



EVRAZ North America in Regina, Saskatchewan and Camrose, Alberta, is being held at stockpile sites in B.C. and Alberta.

The federal government has said the expansion will be operational by mid-2022.

LNG

► The Woodfibre LNG project near Squamish, B.C., is one step closer to building what it describes as the cleanest LNG export facility in the world.

The BC Oil and Gas Commission approved Woodfibre LNG's permit for its export facility.

The permit specifies requirements the project must comply with for design, construction and operation of the Woodfibre LNG project, with a focus on public and environmental safety.

Woodfibre LNG had previously received three major environmental assessment approvals.

With the permit in place, the company is working towards a final decision to proceed with the project.

► New construction contracts continue to be awarded for the LNG Canada project, currently being built at Kitimat, B.C.

Lead contractor JGC Fluor recently awarded a joint venture of Brussels-based BESIX and Vancouver Pile Driving with the construction

of a 500-meter-long quay wall, an LNG platform and all associated mooring and berthing structures.

Construction will start in 2019 with the removal of the existing facilities, shoreline protection and current infrastructure, BESIX said. Meanwhile, Perth, Australia-based Clough was awarded the EPC for the project's loadout line trestle.

Construction on the \$40-billion LNG export terminal began in late 2018.

LNG Canada joint venture partners Shell, PETRONAS, PetroChina, Mitsubishi and KOGAS officially handed off construction to JGC Fluor in April. The project is expected to start operating in 2024/2025.

► A proposed floating LNG terminal at Kitimat, B.C. has initiated its environmental review, targeting operations in 2025.

The Impact Assessment Agency of Canada will determine whether an environmental impact assessment is required, now that it has received formal initial documents from its proponent, the Haisla Nation .

In May 2016, Haisla-owned company Cedar LNG was issued a 25-year LNG export license by the National Energy Board, with the possibility of extension to 40 years. The Cedar LNG project proposes to process and liquefy approximately 400

million to 500 million cubic feet per day of natural gas into approximately 3 million to 4 million tonnes per annum of LNG.

Project construction is planned to start in 2022, followed by operations in 2025.

Pembina Asset Acquisition

► Calgary-based Pembina Pipeline Corporation announced a deal to acquire \$4.35-billion worth of midstream oil and gas assets from Kinder Morgan Inc.

Through the Transaction, Pembina will acquire KMI subsidiary Kinder Morgan Canada Limited and assets including the Cochin Pipeline System, the Edmonton storage and terminal business and Vancouver Wharves, a bulk storage and export/import business. The transaction is expected to close in the first half of 2020.

Rail

► Canadian crude-by-rail exports climbed slightly in June, marking the fourth straight month of increases.

Exports totalled 286,701 bbls/d in June, according to new data released by the National Energy Board (NEB) this morning. That's up from 285,131 bbls/d in May. June 2018 exports averaged 202,677 bbls/d.

Downstream News

Refining

► Statistics Canada data for 2018 shows that more than \$1 billion worth of Alberta crude was exported by tanker via Vancouver, with one-third going to China: 6.3 million barrels, valued at \$442 million.

More than one million bbls went to South Korea and Hong Kong. U.S. refiners bought 10.7 million bbls, valued at \$855 million.

This evidence goes against often foreign-funded activists opposed to the Trans Mountain Pipeline Expansion.

Globally, a mismatch between what is being produced — a whole lot of light oil in the U.S. — and what many refiners need — heavy crude — adds up to a looming increased demand for heavy oil, with Canada being one of the few countries capable of meeting that demand, if it can get its product to tidewater, says Anas Alhajji, an expert in global petroleum markets.

“I don’t think anyone who is familiar with those issues questions the profitability or the business of this pipeline,” he said of the Trans Mountain expansion project.

“We are hearing new voices right now because they are desperate. They want any evidence to support their case. There is no business case against the pipeline.”

► Husky Energy says it has the required permit in hand to start rebuilding its refinery in Superior, Wisconsin, approximately a year-and-a-half after a major fire in April 2018 resulted in the facility suspending operations.

Demolition of damaged equipment is now largely complete, the company said on Monday. The rebuild is expected to take place over the next two years, with a return to full operations in 2021.

Husky says its internal investigation of the incident is largely consistent with the

findings of the U.S. Chemical Safety Board, which concluded that the initial explosion was caused by a failed slide valve that allowed a flammable mixture to form inside the facility’s catalytic cracking unit.

Husky bought the 50,000 bbl/d refinery from Calumet Specialty Products Partners of Indiana for about \$570 million in late 2017.

As the first refinery along the route of the Enbridge Mainline, Superior is integral to Husky’s upstream/downstream business corridor, which processes Canadian heavy crude into products such as gasoline, diesel and asphalt for the U.S. Midwest market, it says.

Husky says the rebuilt refinery will be “modernized,” with advances in technology and efficiency. New equipment will also increase heavy oil processing capacity by approximately 5,000 bbls/d to 25,000 bbls/d.



► Operators at the Sturgeon Refinery near Edmonton are preparing for a full test of the critical unit that has delayed commercial operations by more than a year.

“Multiple issues” occurred during the commissioning phase of the refinery’s gasifier, which processes the heaviest portion of the bitumen barrel into hydrogen for the refining process and produce pure CO₂ to be captured for enhanced oil recovery.

This included shorter than expected lifespan of the unit’s reactor burners and stress cracking in portions of the stainless steel piping and welds, project owners Canadian Natural Resources Limited and North West Refining said in May.

Repair work on those stress cracks has now been successfully completed and redesigned burners are being installed, the project said. A full test run on the gasifier is expected to begin in September.

“To coincide with this test run, we are also planning a fall shutdown to complete routine maintenance, inspections and repairs on the units that have been functioning and producing diesel since late 2017. This shut down will see an additional ~700 local contractors on site at peak including day and night shift,”

said North West Redwater Partnership spokeswoman Vanessa Goodman.

“Once the gasifier test run and the refinery shutdown are complete later this fall, our best estimate remains that we will be running bitumen through the refinery by the end of this year. “

This assumes that any additional unexpected challenges are overcome without causing further delays, she said.

Petrochemicals

► Inter Pipeline Ltd. isn’t having trouble finding workers to build its \$3.5-billion Heartland Petrochemical Complex, but with an eye on the next activity upswing, the company is investing to build Alberta’s construction workforce capacity.

The company announced it is giving \$580,000 to Women Building Futures (WBF); funding that over three years will help provide pre-apprenticeship training to women in the Edmonton region, and raise awareness about the trades.

“We do mean what we say about diversity and inclusion; it does matter, and if industry can work together to provide more of these opportunities for women to enter into the trades it will help when times are good,” said Inter Pipeline CEO Christian Bayle.

“Good times will come back and some point. We’ll be right back in the labour shortage that we were facing five, six years ago, and there’s a huge untapped resource with women in industrial trades. We’re going to do our bit to help.”

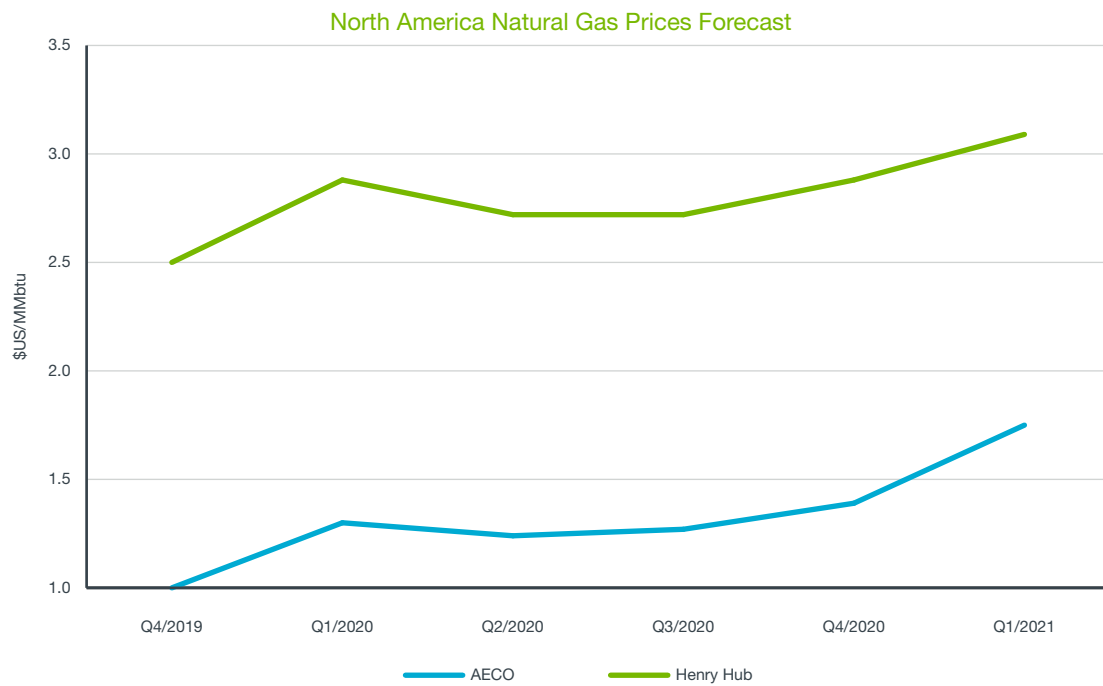
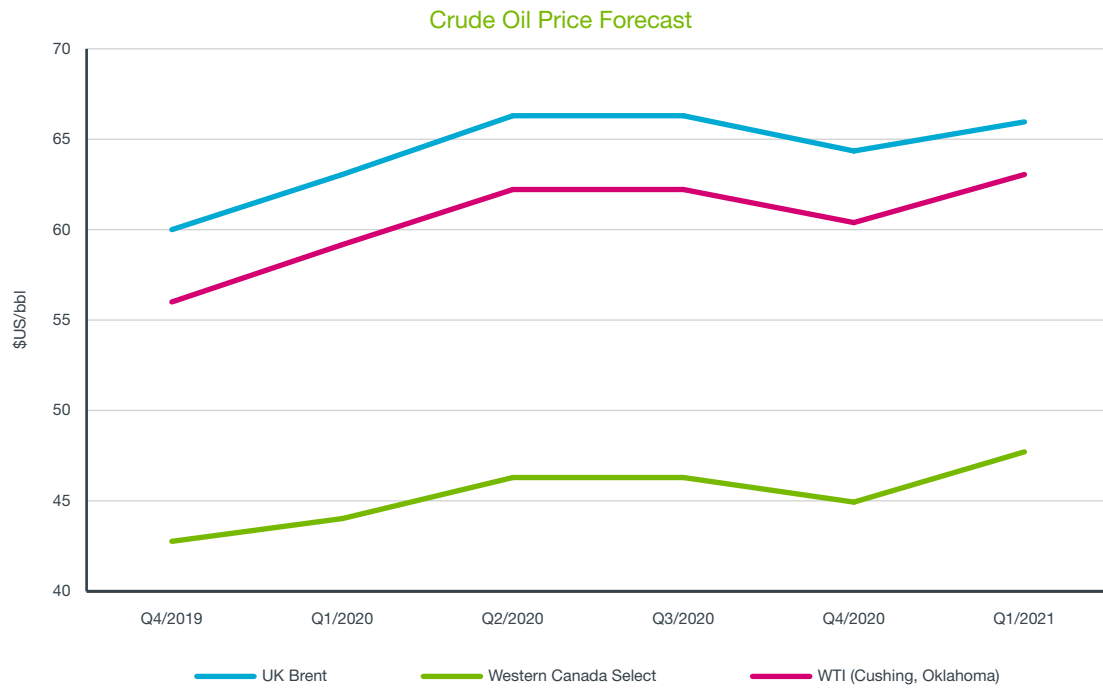
A little over halfway into construction at the Heartland Petrochemical Complex, Canada’s first integrated propane dehydrogenation (PDH) and polypropylene (PP) facility, there is a current workforce of approximately 1,500 on site, Bayle said. That is expected to rise above 2,000 at peak.

Bayle said that of the project’s \$3.5-billion capital cost, about \$2.7 billion is expected to flow into the Alberta economy through direct employment and contracts with Alberta companies.

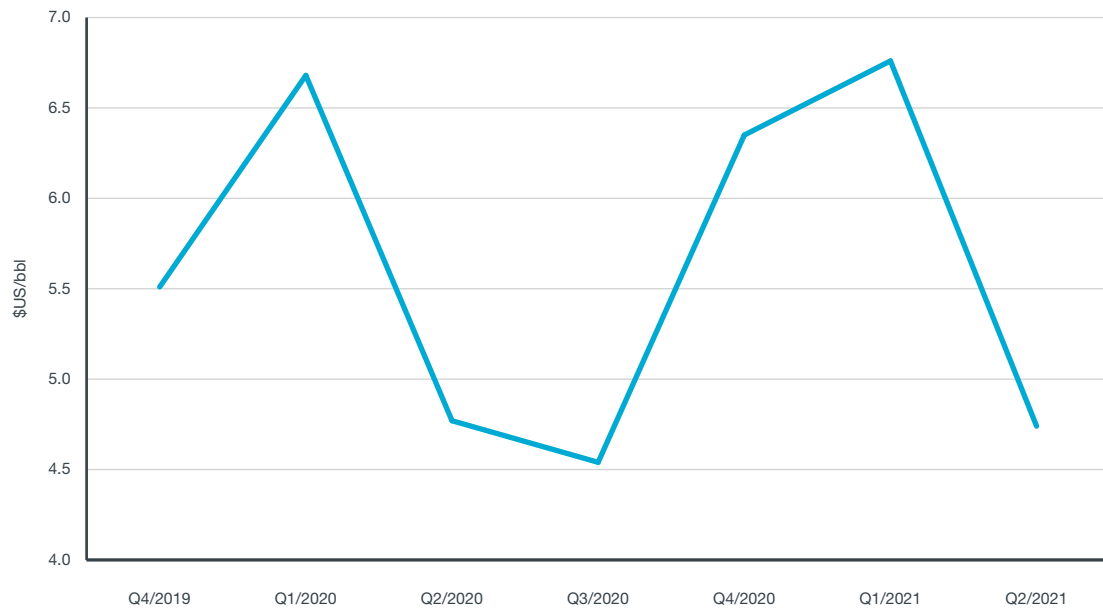
That means approximately 77 percent of the capital spend for the petrochemical project will be within Alberta.

Construction of the Heartland PDH plant is progressing approximately one year ahead of schedule, and the entire project is on track to meet its startup target of late 2021, he said.

Alberta Oil & Gas Data

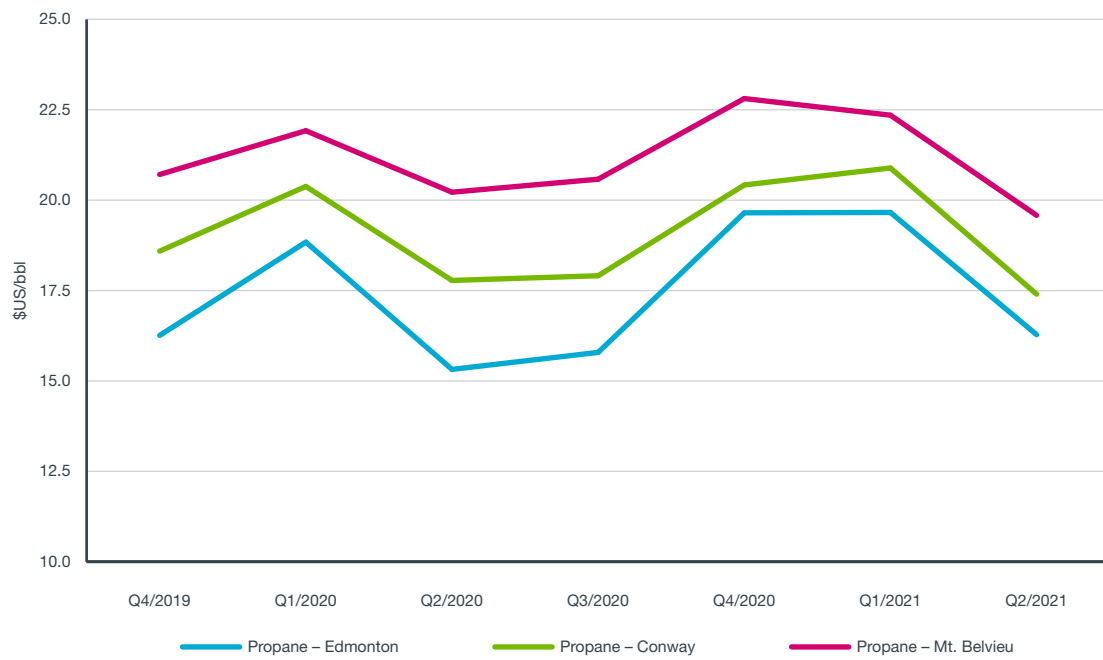


Ethane Price Forecast - Alberta Plant Gate

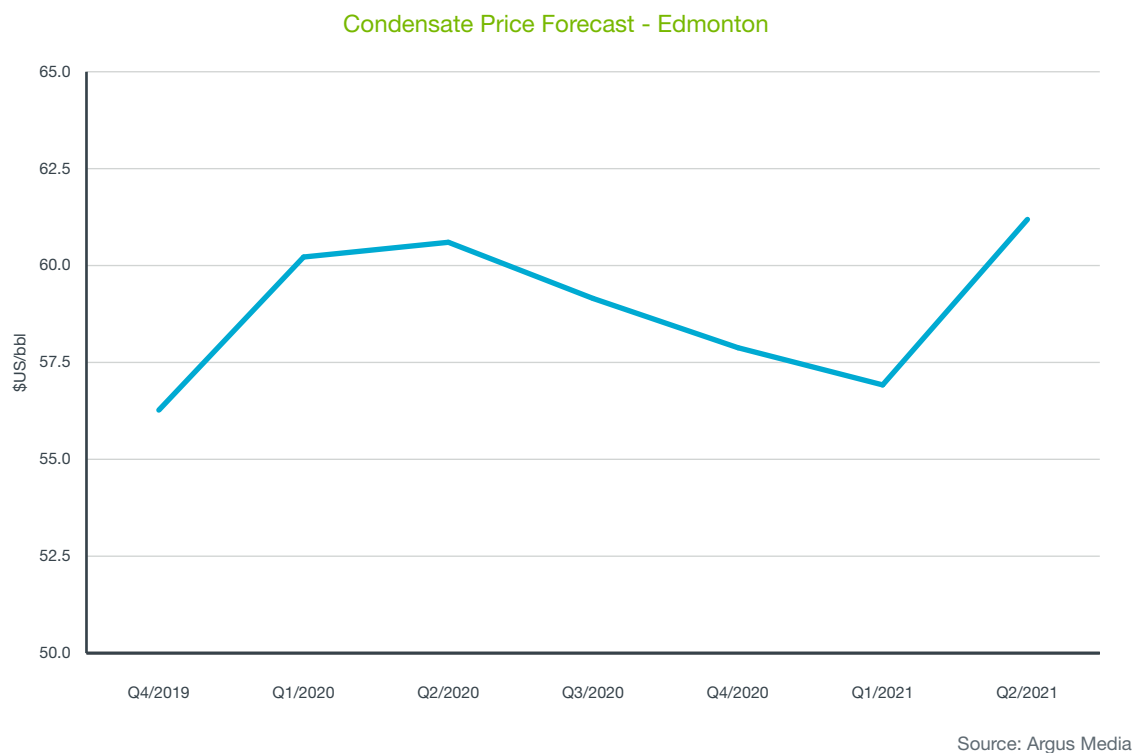
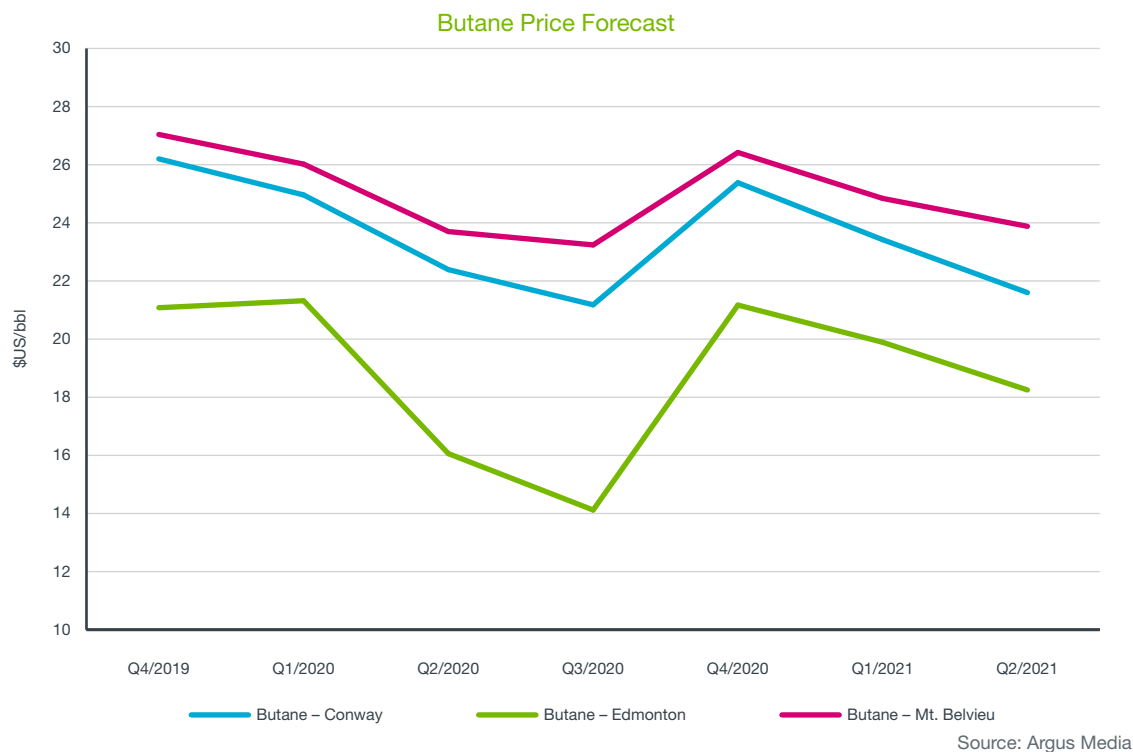


Source: Argus Media

Propane Price Forecast



Source: Argus Media



Connected to North America's Critical Infrastructure: Oil



Connected to North America's Critical Infrastructure: Natural Gas



Crude Oil Plays

Oilsands Upgraders

Operating

- 1** Suncor Base & Millennium
- 2** Syncrude Mildred Lake
- 3** Athabasca Oil Sands Project Scotford
- 4** Canadian Natural Resources Horizon

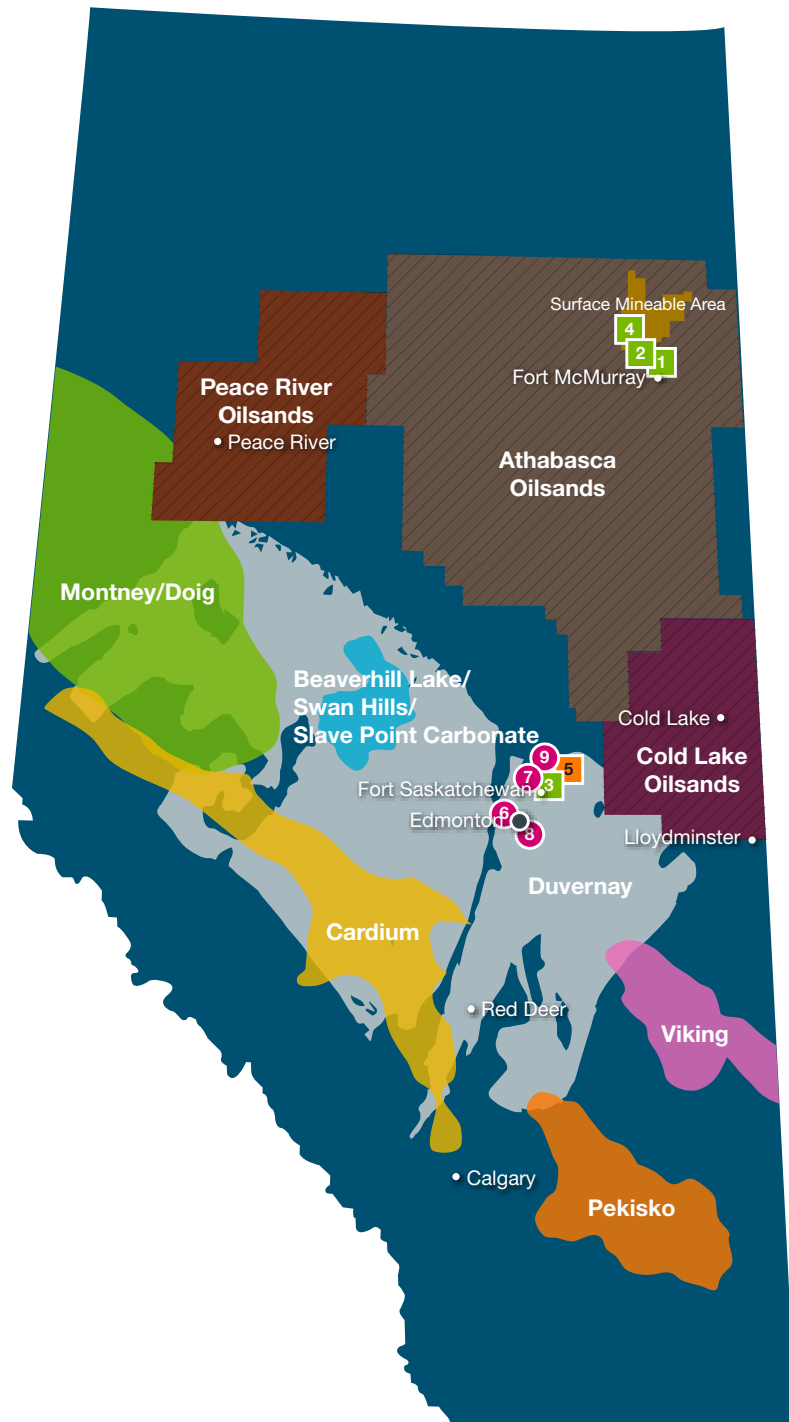
Proposed

- 5** Value Creation Heartland

Oil Refineries

Operating

- 6** Suncor Edmonton
- 7** Shell Scotford
- 8** Imperial Strathcona
- 9** North West Redwater Sturgeon



Natural Gas Plays

Straddle Plants

- 1 AltaGas Ellerslie
- 2 Inter Pipeline Cochrane
- 3 Alta Gas Joffre
- 4 Spectra Empress
- 5 Plains Midstream Empress
- 6 Atco Empress
- 7 1195714 Alberta Empress
- 8 Atco Fort Saskatchewan

Fractionators

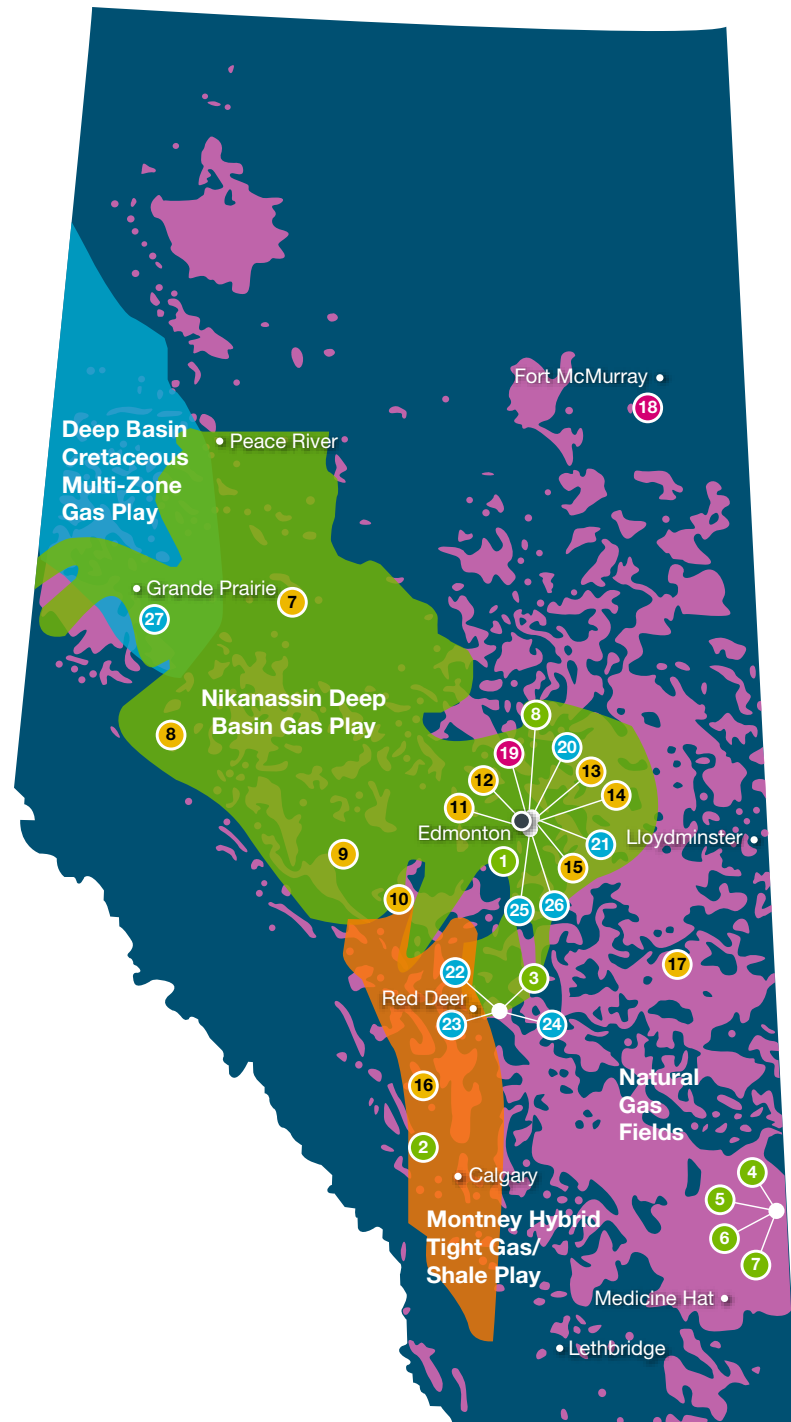
- 7 High Prairie Frac Plant
- 8 Kanata Simonette 13-11 Gas Plant
- 9 Tervita Granada Frac Plant
- 10 Buck Creek Frac Plant
- 11 DOW Fort Sask
- 12 Fort Sask Gas Plant
- 13 Keyera Fort Sask Frac Plant
- 14 Interpipeline ROF Facility
- 15 Pembina INFRA. & Logistics LP FRAC 1, 2 & 3
- 16 Harmattan Fractionation
- 17 Gibson Hardisty

Offgas Plants

- 18 Inter Pipeline Fort McMurray
- 19 Heartland Offgas Delivery (4917)

Petrochemical Facilities

- 20 Pembina PDH/PP (Under Construction)
- 21 Fort Sask: DOW
- 22 Joffre E1: NOVA
- 23 Joffre E2: NOVA
- 24 Joffre E3: DOW/NOVA
- 25 Inter Pipeline Heartland Petrochemical Complex (Under Construction)
- 26 Inter Pipeline Acrylic Acid & Derivatives Project (Proposed)
- 27 Nauticol Energy Methanol Facility (Proposed)



Myth-Busting

Myth: Natural gas development is as emissions-intensive as coal



A recent report by the International Energy Agency (IEA) pokes a hole in the assertion made by some anti-fossil fuel advocates that natural gas and LNG are just as bad, or even worse, than coal in terms of global warming potential because of fugitive methane leaks.

“Our detailed assessment of today’s lifecycle emissions of gas and coal supply finds that switching to natural gas yields significant emissions reductions in nearly all cases,” the IEA concluded.

In the U.S., nearly one-fifth of total emissions reductions since 2010 (18 percent) have come as a result of switching from coal power to natural gas, the IEA noted.

In 2018, gas on average resulted in 33 percent fewer emissions than coal per unit of heat used in industry and buildings, and 50 percent fewer emissions than coal per unit of electricity generated.

“We estimate that up to 1.2 gigatonnes of CO₂ could be abated in the short term by switching from coal to existing gas-fired plants, if relative prices and regulation are supportive,” the IEA said.

“While there is a wide variation across different sources of coal and gas, we estimate that over 98 percent of gas consumed today has a lower lifecycle emissions intensity than coal when used for power or heat.”

China and India account for more than 60 percent of the coal burned in the world. One might therefore assume this is the biggest potential market for switching from coal to natural gas.

But the IEA report found that Europe and the U.S. are the best potential markets – at least in the utility power generation space – not Asia.

That’s because so many coal power plants in the U.S. and Europe are old, nearing retirement age anyway, and can switched over to gas relatively easily.

Many of the coal power plants in India and China are much newer, so early retirement of those younger plants would require natural gas and LNG prices to be substantially lower than they are now.

However, the IEA added that natural gas does have prospects in China in sectors other than power generation – heating, heavy industry and transportation.

It also found a strong case for gas and LNG in providing firm power to backstop intermittent wind and solar power in China and India.

Another advantage in favour of switching from coal to natural gas in Asia is that it produces fewer air pollutants, which is one of the big drivers for phasing out coal in China – to improve air quality.

Contacts

Alberta Government

Alberta Advanced Education

www.alberta.ca/advanced-education

Alberta Energy

www.alberta.ca/energy

Alberta Energy Regulator

www.aer.ca

Alberta Environment and Parks

www.alberta.ca/environment-and-parks

Alberta Geological Survey

www.ags.aer.ca

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albertainnovates.ca

Alberta Surface Rights Board

www.surfacerights.alberta.ca

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Alberta Land Surveyors' Association

www.alsa.ab.ca

Canada's Natural Gas

www.canadasnaturalgas.ca

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www.cagc.ca

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www.gpacanada.com

Petroleum Services Association of Canada

www.psac.ca

Petroleum Technology Alliance Canada

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