Institute for Energy Economics and Financial Analysis

# British Columbia LNG Project Costs Rising Again

*LNG Projects in Western Canada Burdened by High Costs, Gas Supply Challenges*

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# Key Findings

**Ballooning construction costs for pipelines and liquefied natural gas (LNG) facilities are creating new financial risks for western Canada's LNG industry.**

**Cost estimates for the Coastal GasLink pipeline, designed to supply the LNG Canada project in Kitimat, B.C., have gone up at least 70%, undermining the project's economic competitiveness.**

**British Columbia's gas producers face rising costs from a new royalty regime, and producers in both B.C. and Alberta face regulatory uncertainty stemming from a successful legal challenge brought by First Nations groups.**

**Rising construction and gas transportation costs, coupled with mounting uncertainty about gas permitting and production, have created a challenging environment for new LNG projects, including the proposed Woodfibre LNG project in Squamish, B.C.**

# Executive Summary

In 2021, IEEFA reported that potential cost overruns on the Coastal GasLink (CGL) pipeline could become an impediment to further development of liquefied natural gas (LNG) projects in western Canada.[1] The CGL pipeline is designed to supply natural gas to the LNG Canada project in Kitimat, B.C., the only LNG project currently under construction in the country. IEEFA argued that rising construction costs and policy challenges had eroded LNG Canada's financial underpinnings, casting a pall on proposals to build more LNG export capacity on Canada's west coast.

In retrospect, this dour assessment may not have been nearly grim enough.

The developer of the CGL pipeline announced in July 2022 that total pipeline construction costs had escalated by 70%. At the end of November 2022, the company said that costs had risen again, and that the company will provide a new estimate of higher costs early this year. The news came as western Canada's oil and gas industry faced a new royalty regime and other challenges that will likely raise gas production costs and create uncertainty about future production volumes.

IEEFA's analysis of the changing costs and challenges for western Canada's gas industry finds that:

- Mounting CGL pipeline construction costs will likely lead to higher tariffs for shipping natural gas from northeast B.C. to the B.C. coast.
- Higher CGL fees, in turn, may make it more profitable for independent western Canadian gas producers to sell gas to U.S. markets using existing pipeline networks, rather than to LNG projects on the B.C. coast.
- At the same time, gas producers in B.C. face rising costs from a new royalty regime, as well as the need for their actions to be consistent with a B.C. Supreme Court decision on First Nations treaty rights.

[1] IEEFA. Review of LNG Canada Project: Delays, Policy Changes and Rising Costs. November 2021.

- Rising gas production and transportation costs, coupled with mounting uncertainty about gas well permitting and production, have created a challenging environment for new LNG projects, including the proposed Woodfibre LNG project in Squamish, B.C.

# The 70% Cost Increase at CGL Puts Canadian LNG Projects at a Disadvantage

TC Energy, the developer of the Coastal GasLink (CGL) pipeline, announced in July 2022 that total costs for completing the pipeline had escalated by 70%, rising from an original cost estimate of CAD$6.6 billion in 2018 to CAD$11.2 billion in 2022.[2,3] In November, the company announced that its costs had risen yet again.[4] The company has not yet provided new cost estimates, but has warned that the inflationary effects of rising labour costs could result in final costs surpassing CAD$11.2 billion.[5]

The price hike for the CGL pipeline is not an anomaly. The Canadian government announced in February 2022 that its Trans Mountain Pipeline Expansion (TMX) project, designed to ship crude oil from Alberta to the B.C. coast, experienced a 70% cost increase over just two years, with construction expenses rising from CAD$12.6 billion in 2020 to CAD$21.4 billion in 2022.[6] The ballooning costs attest to the fact that building major oil and gas pipelines in Canada is extremely expensive.

TC Energy has told investors that it expects its capital portfolio to realize an unlevered after-tax return of 8%.[7] Calculations by IEEFA show that even TC would need to increase tariffs on CGL to about CAD$2 per million British thermal units (MMBtu) to achieve this investment target, even if costs do not rise above CAD$11.2 billion.[8] Meanwhile, S&P Global now estimates CGL

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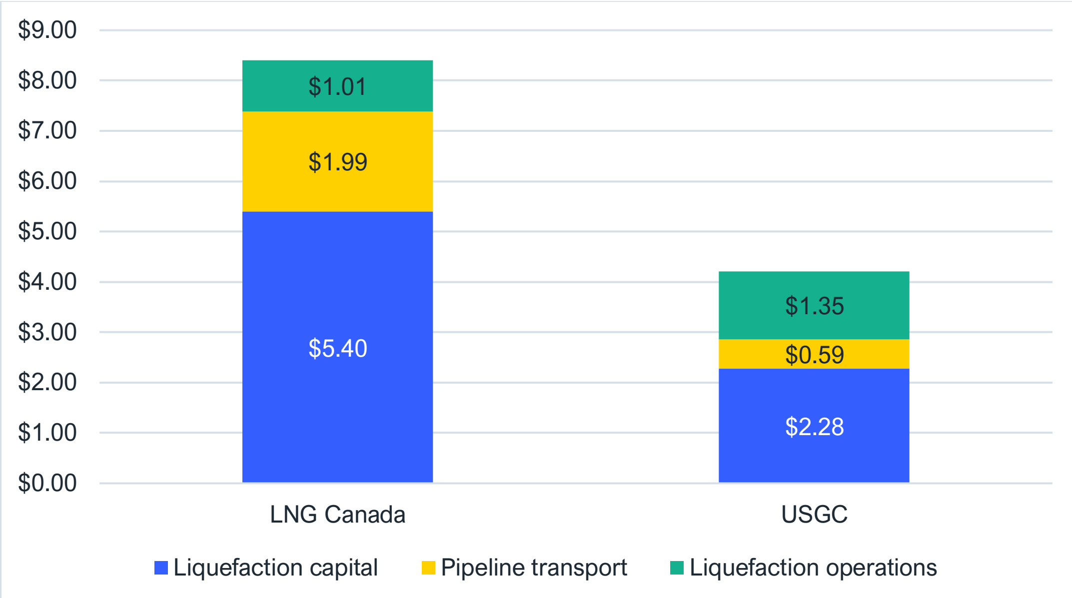
[2] The Globe and Mail. Cost estimate for Coastal GasLink pipeline soars 70 per cent to $11.2-billion. July 28, 2022.
[3] For this report, U.S. dollars are converted to Canadian dollars at a 1.30 foreign exchange rate.
[4] Reuters. TC Energy sees higher costs for troubled Coastal GasLink pipeline. November 29, 2022.
[5] TC Energy. Quarterly Report to Shareholders. November 2022. Page 5.
[6] CBC. Cost of Trans Mountain pipeline expansion soars 70% to $21.4 billion. February 2022. Also see: Financial Post. Cost to build Trans Mountain pipeline jumps 70% to 12.6 billion. February 7, 2020 (regarding previous 70% price hike that occurred from 2017 to 2020).
[7] TC Energy. 2021 Virtual Investor Day. 2021. Slide 93.
[8] Coastal GasLink costs estimated by IEEFA, December 2022, based on pipeline construction costs of $11.2 billion; an 8% project-level internal rate of return (IRR); a 30-year depreciation schedule; 85% utilization 2026-2028 and 100% utilization thereafter; and a 40% operating cost margin, per TC Energy, Keyera and Pembina Pipelines.

transportation costs at CAD$2.60/MMBtu, substantially above IEEFA's estimate.[9] Whether TC Energy can negotiate with LNG Canada to recoup its costs by raising tariffs remains an open question. Yet the fact remains that the escalation of construction expenses has substantially boosted the cost of delivering gas via the CGL.

Costly infrastructure has long created challenges for Canadian LNG projects. In 2022 dollars, capital costs for LNG Canada are more than twice the capital cost of projects on the U.S. Gulf Coast.[10] Meanwhile, the costs of pipeline transportation of gas feedstock in the U.S. Gulf Coast were 70% below the estimated cost of transportation via the CGL.[11] Lower capital and transportation costs more than make up for the LNG higher operating costs on the Gulf Coast, and will require LNG Canada to obtain gas feedstock at a substantial discount to U.S. Gulf Coast projects to remain economically competitive (Figure 1).

[9] S&P Global. LNG Analytics. January 2023.
[10] The Oxford Institute for Energy Studies. Canadian LNG Competitiveness. December 2019.
[11] U.S. Gulf Coast pipeline costs estimated by IEEFA from The Oxford Institute for Energy Studies. Canadian LNG Competitiveness. December 2019. Dollar figures inflated from 2019 to 2022 based on Bank of Canada. Inflation Calculator. Accessed January 2023.

**Figure 1: Selected Costs, LNG Canada vs. U.S. Gulf Coast LNG Projects**[12,13,14,15]




*Note: All figures in 2022 Canadian dollars. Conversions from USD at 1.3.*

The increase in CGL construction costs has combined with other inflationary pressures to boost LNG Canada's costs substantially over the last 3 years (Table 1). Even so, the project's joint owners—Shell, Petronas, PetroChina, Mitsubishi, and Korea Gas—may still reap profits from the project, particularly if global LNG prices remain elevated and the equity owners can source low-cost gas feedstock for the project from their own natural gas production assets in B.C.'s Montney Basin.

[12] Operations costs for both LNG Canada and USGC LNG projects, and pipeline transportation costs for USGC projects, estimated by IEEFA from The Oxford Institute for Energy Studies. Canadian LNG Competitiveness. December 2019.
[13] Pipeline transportation costs for LNG Canada estimated by IEEFA based on pipeline construction costs of $11.2 billion; an 8% project-level internal rate of return (IRR); a 30-year depreciation schedule; 85% utilization 2026-2028 and 100% utilization thereafter; and a 40% operating cost margin, per TC Energy, Keyera and Pembina Pipelines.
[14] Liquefaction capital costs for both LNG Canada and USGC LNG projects estimated by IEEFA from S&P Global. LNG Analytics. Accessed January 2023. The Oxford Institute for Energy Studies. Canadian LNG Competitiveness. December 2019. S&P Global. LNG Analytics. Accessed January 2023. Bank of Canada. Inflation Calculator. Accessed January 2023. Note that USGC LNG capital costs represent a weighted average for new US LNG projects under construction as of December 2022.
[15] Where applicable, 2019 Canadian dollars inflated to 2022 Canadian Dollars by IEEFA from Bank of Canada. Inflation Calculator. Accessed January 2023.

**Table 1: Cost estimates for LNG Canada delivery to Asia, 2019 vs. 2022[16,17,18,19,20,21,22]**

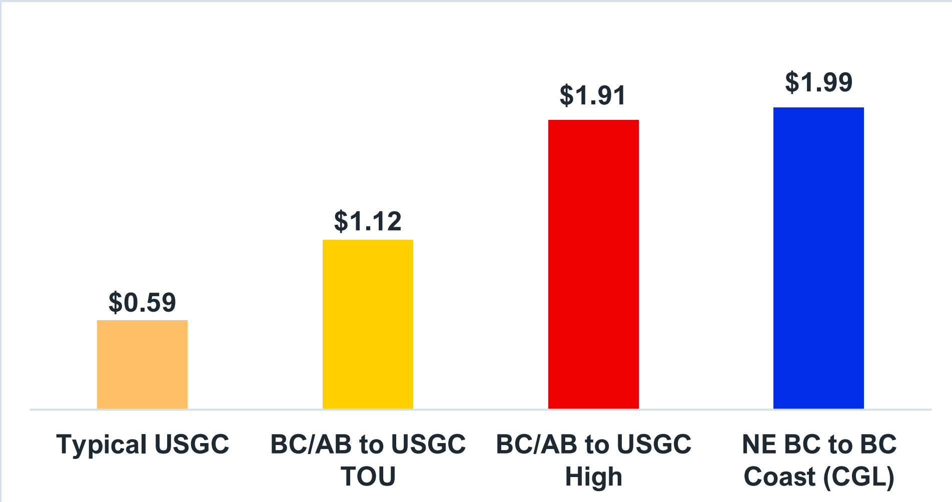
| | 2019 Estimate | 2022 Estimate |
|---|---|---|
| **Upstream development costs** | $0.30 | $0.30 |
| **Gas costs** | $2.60 | $4.52 |
| **CGL pipeline costs** | $1.17 | $1.99 |
| **Liquefaction capital costs** | $4.94 | $5.40 |
| **Operating costs** | $0.90 | $1.01 |
| **Shipping** | $0.83 | $1.13 |
| **Cost, DES Asia** | **$10.74** | **$14.35** |

*Note: All figures in Canadian dollars. Figures for 2019 in 2019 dollars, figures for 2022 in 2022 dollars. Conversions from USD at 1.3.*

Canada's independent natural gas producers, however, have no special motivation to direct gas to LNG Canada. Instead, they will be motivated to seek the maximum returns by selling gas to the highest bidder, regardless of location. High tariffs on the CGL, which will be needed for TC Energy to recoup construction costs for the pipeline, could make it more profitable for independent gas producers in western Canada to sell gas to the U.S. Gulf Coast rather than LNG facilities on the B.C. coast (Figure 2).

[16] Upstream development costs estimated by IEEFA from The Oxford Institute for Energy Studies. Outlook for Competitive LNG Supply. March 2019.
[17] Gas costs for 2019 estimated from Royal Dutch Shell Plc. LNG Canada Final Investment Decision. October 2018.
[18] Gas costs for 2022 estimated by IEEFA from GLJ. Historical Price Charts. January 2023. Costs represent forecasted gas prices at Station 2 in Chelwyck, B.C., at the time that LNG Canada is projected to enter service. Note that equity partners may be able to produce gas at a lower cost than Station 2 prices, yet they would have to forego market revenues at Station 2 to direct gas to LNG Canada. Similarly, if LNG Canada equity partners can't produce enough gas to fulfil their liquefaction allotments, as discussed later in this report, they would pay Station 2 prices for any additional feedgas they would need to supply the liquefaction project. IEEFA therefore takes projected gas prices at Station 2 as the cost of gas supply.
[19] CGL pipeline costs for 2019, liquefaction capital costs for 2019, shipping costs for 2019, and liquefaction operating costs for 2019 estimated by IEEFA from The Oxford Institute for Energy Studies. Canadian LNG Competitiveness. December 2019.
[20] CGL pipeline costs for 2022 estimated by IEEFA, December 2022, based on pipeline construction costs of $11.2 billion; an 8% project-level internal rate of return (IRR); a 30-year depreciation schedule; 85% utilization 2026-2028 and 100% utilization thereafter; and a 40% operating cost margin, per TC Energy, Keyera and Pembina Pipelines.
[21] Liquefaction capital costs for 2022 and shipping costs for 2022 estimated by IEEFA from S&P Global. LNG Analytics. Accessed January 2023.
[22] Liquefaction operating costs for 2022 estimated by IEEFA based on liquefaction operating costs for 2019 and Statistics Canada. Consumer Price Index, monthly, not seasonally adjusted. Accessed January 2023.

### Figure 2: Pipeline Transportation Costs per MMBtu[23,24,25,26]




*Note: All figures in Canadian dollars. Conversions from USD at 1.3. B.C./Alberta to U.S. Gulf Coast (USGC) calculated using Tourmaline Oil's estimates of cost per MMBtu; high case includes cost to transport on Alliance pipeline to Natural Gas Pipeline Company of America.*

Western Canadian gas producers have already signed significant deals to sell gas to the U.S. Gulf Coast. ARC Resources, the third-largest natural gas producer in Canada, signed a 140,000 MMBtu/day agreement in 2022 with Cheniere Energy's Corpus Christi Stage 3 LNG facility.[27] This deal doubles the amount of gas targeted in ARC Resources' original LNG agreement with LNG Canada in late 2021. Tourmaline Oil, Canada's largest natural gas producer, signed a similar agreement to one that ARC Resources signed with Cheniere Energy.[28] In a 2022 corporate presentation, Tourmaline estimated that the cost of shipping gas from the Montney Basin to Louisiana would be USD$0.86 per MMBtu, or about CAD$1.12—significantly less than the costs that IEEFA estimates would be required to ship gas to the B.C. coast via the CGL pipeline.[29]

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[23] Typical USGC costs estimated from The Oxford Institute for Energy Studies. Canadian LNG Competitiveness. December 2019.
[24] Tourmaline's costs to ship gas from B.C./Alberta pipeline to the US Gulf Coast from Tourmaline Oil. Corporate Presentation. September 2022, slide 24.
[25] High case estimated by IEEFA from Natural Gas Pipeline Company of America. FERC Gas Tariff. September 2022. Alliance Pipeline. Tolls and Rates. September 2022.
[26] CGL pipeline costs for 2022 estimated by IEEFA, December 2022, based on pipeline construction costs of $11.2 billion; an 8% project-level internal rate of return (IRR); a 30-year depreciation schedule; 85% utilization 2026-2028 and 100% utilization thereafter; and a 40% operating cost margin, per TC Energy, Keyera and Pembina Pipelines.
[27] ARC Resources. Investor Presentation. September 2022, slide 12.
[28] Tourmaline Oil. Corporate Presentation. September 2022, slide 24.
[29] *Ibid*.

As North American and global markets evolve, western Canadian gas producers may see the U.S. markets as an attractive option that avoids the high tariffs associated with shipping gas to the B.C. coast. Canadian natural gas producers may find it more lucrative to avoid high CGL tariffs and instead contract with Gulf Coast LNG projects or other customers in the U.S. or Canada.

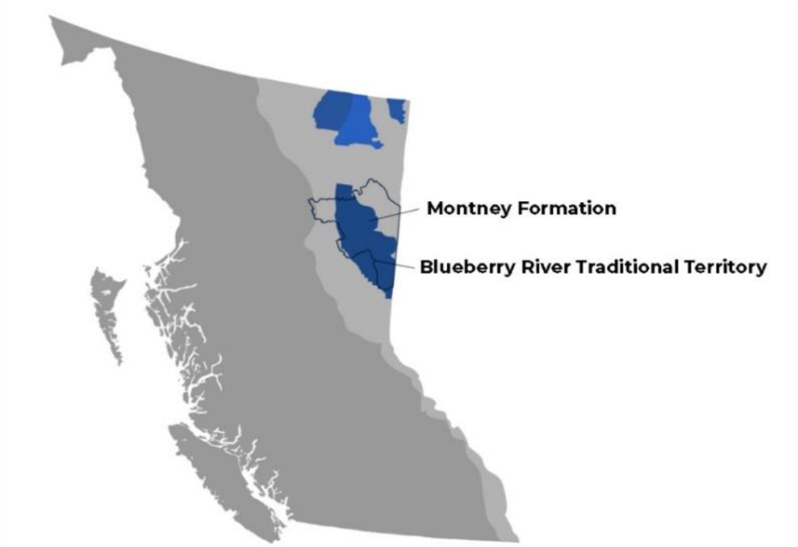
# Natural Gas Supply Challenges for LNG Projects in Western Canada

Although global LNG prices have come down from their highs of 2022, they remain well above historical averages. This will likely add momentum to the completion of LNG Canada, despite rising costs. But recent changes to the upstream regulatory environments in B.C. and Alberta could affect the cost and availability gas supplies that Western Canada's LNG industry will rely upon as feedstock.

In June 2021, the Supreme Court of British Columbia ruled that the cumulative impacts of oil and gas development, forestry, and other resource extraction had violated the Blueberry River First Nation's (BRFN) treaty-guaranteed rights to pursue traditional economic activities, including fishing and hunting.[30] The BRFN's traditional territory overlaps substantially with B.C.'s gas-rich Montney Basin (Figure 3).

[30] *Yahey v British Columbia*, 2021 BCSC 1287 (June 29, 2021). Also see: Osler. British Columbia Supreme Court issues precedent-setting cumulative effects decision. July 2021.

### Figure 3: Blueberry River First Nations Traditional Territory and Montney Formation[31]

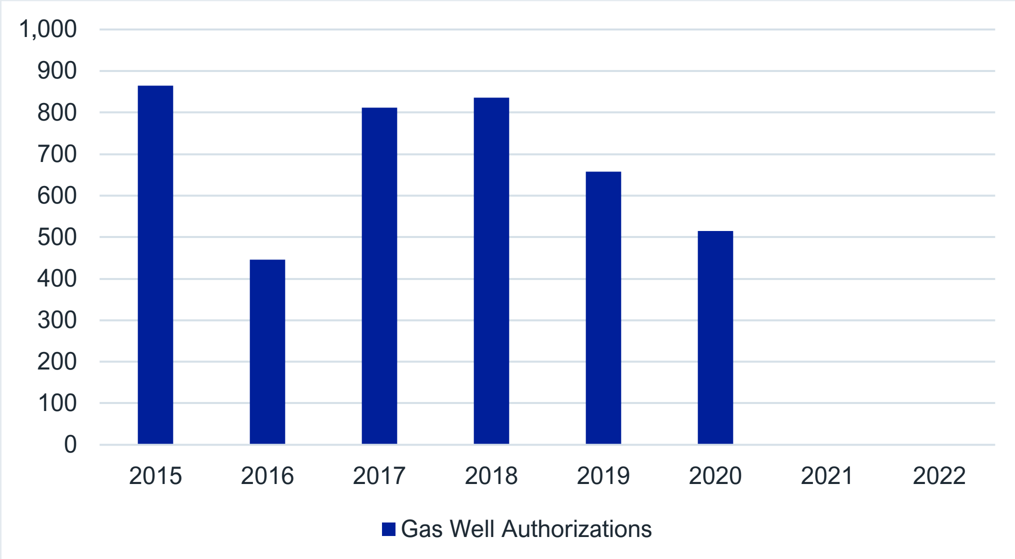



*Note: Represents 38,000 square kilometres, in which all major Montney production players operate (ARC Resources, Shell, Tourmaline, Canadian Natural Resources, Petronas, Ovintiv).*

This decision resulted in a *de facto* moratorium on new drilling permits in the province in 2021 and 2022 (Figure 4). In October 2021, the B.C. government reached a preliminary agreement with the BRFN, allowing certain already-permitted projects to proceed, even as many new authorizations were paused.[32] Although new gas wells that were authorized before the B.C. Supreme Court decision continued to come online in 2021 and 2022, by late 2022 some producers warned that the industry was running short of permits for new wells, even as other companies shifted capital budgets away from the Montney due to the regulatory uncertainty affecting the region.[33]

[31] XI Technologies (BOE Report). Wednesday Word to the Wise: Blueberry River First Nations overview. November 17, 2021.
[32] B.C. Government. B.C., Blueberry River First Nations reach agreement on existing permits, restoration funding. October 7, 2021.
[33] Reuters. Canadian natgas firms warn clock ticking on Montney shale deal with First Nations. November 1, 2022.

## Figure 4: Natural Gas Permits Authorized in B.C. by Year




*Source: B.C. Oil & Gas Commission. Well Authorizations Approved – Monthly by Status. 2015 – 2022.*

After more than a year of negotiations, the B.C. government recently announced that it had reached an agreement with the BRFN that would allow new permitting for new oil and gas wells on BRFN lands. However, the agreement will require the oil and gas industry to slash the physical footprint of new development in half. The deal limits total annual land disturbance by the oil and gas industry on BRFN territory to 750 hectares per year, down from roughly 1,500 per year prior to the agreement.[34] In addition, the BRFN will establish permanently protected areas, and wherever possible, new oil and gas development will focus on lands that have already been disturbed.

Some oil and gas industry representatives praised the agreement for breaking the regulatory logjam that had prevented new well authorizations for several years, and for giving more regulatory clarity and certainty for producers.[35] Meanwhile, B.C. Premier David Eby emphasized that the agreement is a cap on land disturbance, not oil and gas production, and that the gas industry would need to be "innovative" to "find ways to work with less land disturbance."[36]

[34] B.C. Government. Province, Blueberry River First Nations reach agreement. January 18, 2023.
[35] B.C. Government. Province, Blueberry River First Nations reach agreement. January 18, 2023.
[36] CTV News. 'It's a good day' : Blueberry River First Nations signs historic agreement with B.C. government. January 18, 2023

Yet many details of the agreement are still up in the air, and significant uncertainty remains for B.C.'s gas industry. First and foremost, it remains an open question how the agreement might affect gas supplies and costs, particularly as the industry ramps up to supply feedgas to LNG Canada. The B.C. Montney currently produces about 6 billion cubic feet of gas per day (Bcf/d). When LNG Canada is launched, it will add about 2 Bcf/d of new demand. Based on recent well productivity in the Montney, boosting B.C. Montney gas output to 8 Bcf/d by 2026 could require the industry to bring roughly 35 to 40 new gas wells into service each month for the next five years—a pace that exceeds the industry average over previous five years.[37]

In short, it is likely that as LNG Canada moves towards completion, B.C.'s gas industry will have to increase the pace of drilling, even as it cuts the physical footprint of new oil and gas development in half. And while the industry has been able to boost average output from new Montney wells, primarily by increasing lateral length, longer laterals also can boost costs. The industry also may be forced to experiment with new techniques of drilling multiple wells from a single drilling pad, with uncertain impacts on production volumes and costs.

A second key uncertainty will come from the need for regulators to decide which companies get to disturb how much land. With a firm limit of 750 hectares of new land disturbances by the oil and gas industry, regulators may be forced to pick and choose which companies will be allowed to move forward with development projects that disturb new lands. In the process, the new agreement could create a new set of regulatory uncertainties for B.C.'s producers. In one sense, companies that disturbed a significant amount of land within BRFN traditional territory prior to the agreement may find themselves at a competitive advantage to their peers, since they could rely on previously disturbed lands for new drilling. However, since most companies drill their more promising wells first and save more speculative wells for later, these companies may also encounter more challenging economics for newer wells.

Uncertainties around the issuance of permits and gas production may soon affect neighbouring Alberta as well. In October, the Duncan's First Nation (DFN), whose traditional lands cover much

[37] IEEFA estimate, based on analysis of S&P Global data.

of the natural gas-rich Alberta Montney formation,[38] filed a lawsuit against the province of Alberta that echoed BRFN's claims against the B.C. government.[39] If the lawsuit is successful, it could create the same sorts of regulatory uncertainties for the Alberta Montney as have been experienced in the B.C.[40] Montney. IEEFA's prior analysis of LNG Canada noted the BRFN decision would likely have major impacts on the development of B.C. natural gas. The fact that Alberta is now part of this discussion magnifies the impact of the BRFN decision.

Although much remains uncertain about the ultimate effects of the BRFN decision, it is possible that western Canada's gas industry will face a combination of higher production gas costs and constraints on output that could place B.C. LNG projects at a competitive disadvantage to other global LNG projects.

Changes to B.C.'s royalty regime add to the economic challenges affecting the province's upstream gas industry:

- In B.C., the deep well royalty program—the largest subsidy in its natural gas industry—will be eliminated.
- Minimum royalty rates will increase from 3% to 5%.[41]

The new royalty system is being phased in over two years, and began Sept. 1, 2022. The new royalty regime will likely be fully in place when LNG Canada comes online.

For LNG Canada's owners, direct access to overseas LNG markets could mitigate the increased costs stemming from the new royalty system. But if development of new gas wells is constrained for any reason, including as a result of the new regulatory regime in the BRFN territory, LNG Canada's owners may be forced to turn to higher-priced natural gas from the market—instead of gas they produce—to supply their liquefaction plant. Higher gas prices, in turn, would increase long-term LNG costs.

[38] Duncan's First Nation. Duncan's First Nation Comments Related to Bill C-69. April 6, 2018.
[39] XI Technologies (BOE Report), *op. cit.*
[40] Osler. Treaty infringement claims for cumulative effects come to Alberta. August 2022. Also see McCarthy Tetraut. Power Perspectives 2022. March 17, 2022.
[41] B.C. Government. New oil and gas royalty system ending inefficient subsidies. May 2022.

The dual effect of increased costs from the CGL pipeline and potential rising costs for future natural gas supply due to diminished gas production development in northeast B.C. could put LNG Canada and any future LNG facility in western Canada at a competitive disadvantage to other LNG projects in North America and around the globe.

# Woodfibre LNG: Dimming Outlook for Canadian LNG

LNG Canada, which was reportedly 70% complete in late September,[42] has had the advantage of well-funded partners who own and control both the production and liquefaction of natural gas.[43] Also, with the exception of Shell, which intends to sell LNG based on its portfolio of global LNG contracts and assets, LNG Canada's partners collectively have contracted 94% of their LNG cargoes for an average life of 13.4 years, guaranteeing long-term revenues.[44, 45, 46] Other proposed B.C. LNG projects don't have these advantages.

Of the many western Canadian LNG projects that have been proposed, the Woodfibre LNG project, in Squamish, B.C., appears best positioned to move forward in the near future.[47] Yet Woodfibre's ability to financially support its project is less assured than that of LNG Canada. Woodfibre's majority owner, Pacific Energy, is a relatively small company compared with LNG Canada's backers, and it is a recent entrant into the global gas industry. In addition, Woodfibre has only contracted 70% of its LNG cargoes over 15 years with BP.[48]

Woodfibre LNG plans to leverage existing pipeline capacity from the Montney Basin to Vancouver to supply the project with gas. The project, however, will still require pipeline

[42] Business in Vancouver. LNG Canada 70% complete. September 29, 2022.
[43] PetroChina Company Limited. PetroChina invests in Phase 1 of its Canadian LNG Project. October 2018. Also see: IEEFA. LNG Canada's BC project likely last for country's liquefied natural gas industry. November 24, 2021, p. 4.
[44] Petronas, with a 25 percent stake in LNG Canada, has agreements in place for 3 million tons per annum (MTPA) of its 3.5 MTPA share. Petronas. Petronas and CNOOC Sign 10-Year LNG Supply Agreement. July 2021. Also see: Reuters. LNG Canada gets another buyer as Vitol inks supply deal with Petronas. November 2018.
[45] Mitsubishi, with a 15% stake in LNG Canada, has agreements in place for its 2.1 MTPA share. Reuters. Japan's JERA to buy up to 1.2 million tons per year of LNG from Canada project. April 2019. Also see: Petrol Plaza. Tokyo Gas signs agreement to purchase LNG from LNG Canada project. October 2018. Also see: Offshore Energy. Toho Gas inks LNG Canada supply deal. October 2018.
[46] PetroChina and the Korean Gas Corporation (KoGas) with stakes of 15% and 5% in LNG Canada, respectively, are government-established companies that provide natural gas distribution services.
[47] Reuters. Canada sees west coast LNG revival as world scrambles for gas. August 2022.
[48] IHS Markit. Woodfibre LNG. June 2021, slide 33.

expansions for Enbridge’s T-South pipeline and Fortis’ Eagle Mountain-Woodfibre natural gas pipeline (Figure 5).[49] Pacific Energy acquired natural gas production assets in northeast B.C. to provide about 70% of Woodfibre’s natural gas needs.[50]

### Figure 5: Pipeline System Intended to Source Natural Gas from the B.C. Montney for the Proposed Woodfibre LNG Facility


*Source: Enbridge. Bridge to a Cleaner Energy Future. September 2022, slide 12.*

Construction cost increases could pose challenges for Woodfibre’s financial viability. In 2015, Woodfibre LNG estimated that the project would cost between CAD$1.4 billion and CAD$1.8 billion, or roughly $CAD1.7-2.2 billion in 2022 dollars.[51] The associated pipeline was estimated to cost $CAD520 million, or $CAD630 million in 2022 dollars.[52] Based on these estimates, the project’s construction costs would have totalled at most $CAD2.8 billion in 2022 dollars. But last year, the estimated cost for the entire Woodfibre project—including the liquefaction plant, floating storage, and expansion of the gas pipeline supplying the facility—rose to CAD$6.6

[49] *Ibid.*, slide 20.
[50] Pacific Canbriam Energy. Sustainability Report 2021. August 2022, slide 7.
[51] Woodfibre construction cost estimate from S&P Global. Liquefaction Project Profile - Canada: Woodfibre LNG. June 14 2022. See also Government of British Columbia. Woodfibre LNG Project granted environmental assessment approval. October 26, 2015. Inflation estimates from Bank of Canada. Inflation Calculator. Accessed January 2023.
[52] Pipeline cost estimate from S&P Global. Liquefaction Project Profile - Canada: Woodfibre LNG. June 14 2022. See also Government of British Columbia. Eagle Mountain – Woodfibre Gas Pipeline Project: Assessment Report. July 22, 2016. Inflation estimates from Bank of Canada. Inflation Calculator. Accessed January 2023.

billion.[53] This suggests that the comprehensive cost for Woodfibre LNG, including the pipeline supplying the project, has increased by roughly 135% since 2015, only 21% of which can be attributed to general inflation.[54]

In July, Woodfibre LNG sold 30% of its equity to Enbridge, which owns the T-South Pipeline that would supply the terminal.[55] Enbridge plans to spend CAD$1.95 billion on the project—40% as project financing debt and the remaining 60% as preferred equity. Enbridge will provide this capital only as construction progresses, limiting the company's risk exposure.

Enbridge would benefit from the development of Woodfibre LNG through the expansion of its T-South gas pipeline running from Northeast B.C. to the B.C. southern border (Figure 7).[56] Woodfibre LNG will have to pay the T-South tariff for passage of its contracted gas from northeast B.C. to the liquefaction facility (Figure 7). Woodfibre LNG's gas demand is equivalent to 13.3% of throughput via Enbridge's expanded T-South pipeline, and just 3.3% of Enbridge's gas throughput capacity across its entire portfolio of assets. In this context, Enbridge's investment in Woodfibre LNG appears to be a modest step to diversify the company's gas portfolio, rather than a strong endorsement of the business case for LNG construction in B.C.

The steps taken by Woodfibre LNG to secure contracts and funding partners may not be enough to allow the company to begin construction. LNG sales contracts alone do not guarantee that a project will move forward.

There may be parallels between Woodfibre and Tellurian's proposed Driftwood LNG facility in Louisiana, which has suffered from cost increases and commercial setbacks even after securing commitments from potential buyers. In 2021, after failing to raise high-interest bonds to secure just under 8% of the project's costs, Driftwood LNG lost two-thirds of its customer base after both Shell and Vitol cancelled their contracts with the facility.[57] In a video the company issued after the posting of its third quarter 2022 report, Tellurian CEO Charif Souki noted that "our

[53] Enbridge. Woodfibre LNG. Accessed January 2023.
[54] Bank of Canada. Inflation Calculator. Accessed January 2023.
[55] Enbridge. Q2 2022 Earnings Presentation. July 2022, slides 9-16.
[56] Enbridge. Q2 2022 Earnings Presentation. July 2022, slide 13.
[57] IEEFA. Killing blows for Driftwood LNG? September 30, 2022.

industry has not been spared the cost overruns and the reliance on questionable supply chains, so we have seen a significant increase in cost. You can no longer build a facility for the same price as we did 10 years ago."[58]

# Woodfibre LNG Would Siphon Off Low-GHG Power that B.C. Needs for Its Energy Transition

In 2020, Woodfibre LNG released a report prepared by one of its consulting firms, declaring the project to be one of the lowest greenhouse gas (GHG) emitting LNG facilities globally, with a GHG emissions intensity of 0.06 tons per ton of LNG exported.[59] The emissions figure does not, however, include pipeline or upstream GHG emissions, or downstream emissions from the combustion of LNG. For Woodfibre LNG to reasonably achieve completion of construction:

1. Pacific Canbriam Energy—the gas-producing arm of Pacific Energy, the company backing the Woodfibre LNG terminal—will need to ramp up natural gas production by 36% from existing production capacity, which will increase GHG emissions (particularly fugitive methane emissions) from upstream natural gas production.[60]
2. As noted above, both Enbridge's T-South and Fortis' Eagle Mountain-Woodfibre natural gas pipelines would need to expand their infrastructure for the project, adding to GHG emissions from construction and operations.

Furthermore, Woodfibre LNG's claims to a low GHG footprint rely on the plant's use of hydroelectric power that would otherwise be available to further B.C.'s electrification efforts to curb GHG emissions.

[58] Oil & Gas Journal. Tellurian chair notes 'misconception' on infrastructure costs as Driftwood financing efforts continue. November 2, 2022. Also see: Tellurian. Two minutes with Charif Souki on project cost estimates and economic impacts on large scale projects. November 2, 2022.
[59] Mantle314. Woodfibre LNG Facility GHG Emissions Comparison. May 2020, p. 6.
[60] Pacific Canbriam Energy. Sustainability Report 2021. August 2022, slide 7.

Woodfibre plans to use BC Hydro's existing 138 kilovolt (kV) transmission line north of Squamish to provide its LNG facility with power to run the liquefaction trains.[61] Because BC Hydro has an abundance of hydroelectric power, using electricity from BC Hydro would lower the reported GHG intensity of Woodfibre LNG's facility in comparison to the LNG Canada facility, which relies on natural gas turbines for power.[62]

Yet B.C. is relying on hydropower to meet most future provincial energy needs while achieving an 80% reduction in GHG emissions by 2050.[63] The B.C. government has set interim targets for 2030 to reduce GHG emissions by 26 Mtpa (million tonnes per annum) from 2007 levels, and much of that will need to come from electrification.[64] Part of that electrification plan stems from BC Hydro's abundance of renewable electricity from its hydropower assets in the province. BC Hydro expects system energy shortfalls in electricity by 2030, however, which may hinder progress in electrification.[65]

Woodfibre LNG's use of low-GHG hydropower to run its liquefaction trains may jeopardize B.C.'s broader electrification and decarbonization plans. The project would consume 140 to 150 megawatts of power during normal operations, enough to power more than 100,000 homes.[66,67] Alternatively, the province could use power consumed by Woodfibre LNG to advance its other climate goals, such as electrification of transportation. In addition, the increased gas production required to provide gas feedstock to the project will boost climate-warming methane emissions, further undermining the province's climate ambitions. While Woodfibre LNG's use of low-GHG electricity may serve as a useful talking point for marketing and public relations, in reality the project is likely to detract from B.C.'s climate goals.

[61] BC Hydro. Woodfibre LNG Interconnection Project. September 2022. Also see: Woodfibre LNG. How much energy in gigawatt-hours/yr (GWh/yr) will the site require from BC Hydro to export 2.1 million tonnes of LNG/yr? Will air cooling increase the amount of energy required? November 2016.
[62] Ministry of Environment and Climate Change Strategy. Electricity Emission Intensity Factors for Grid-Connected Entities. September 2022. Also see: IEEFA (2021), *op. cit.*, pp. 19-21.
[63] Times Colonist. B.C. emission reduction targets 'based on a fantasy,' say energy experts. February 2022.
[64] CleanBC. Roadmap to 2030. September 2022, p. 30.
[65] BC Hydro. BC Hydro Integrated Resource Plan 2021. September 2022, p. 48.
[66] Woodfibre LNG. How much electric power will your project require on an annual basis? March 24, 2015.
[67] Northwest Power and Conservation Council. Megawatt. Accessed January 2023.

# Conclusion

Although LNG Canada and its major oil and gas partners have moved forward with construction, the project still faces uncertainty around completion costs from the Coastal GasLink pipeline. The escalated cost of the CGL pipeline—coupled with the new royalty regime and the court decision requiring consideration of cumulative impacts on First Nations treaty rights—puts even more doubt on projects that have yet to reach construction, including the anticipated Woodfibre LNG project. As potential Canadian LNG markets evolve in complexity and competition, high-cost infrastructure continues to pose a challenging hurdle for Canadian LNG projects

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The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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