A Pipeline in Search of a Market

Economics and taxpayer risks

September 2026

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Acknowledgements

The Pembina Institute recognizes that the work we steward and those we serve span the lands of many Indigenous Peoples. We respectfully acknowledge that our organization is headquartered in the traditional territories of Treaty 7, comprising the Blackfoot Confederacy (Siksika, Piikani and Kainai Nations); the Stoney Nakoda Nations (Goodstoney, Chiniki and Bearspaw First Nations); and the Tsuut'ina Nation. These lands are also home to the Otipemisiwak Métis Government (Districts 5 and 6).

These acknowledgements are part of the start of a journey of several generations. We share them in the spirit of truth, justice and reconciliation, and to contribute to a more equitable and inclusive future for all.

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Executive summary

This report assesses whether additional export pipeline capacity from the Western Canadian Sedimentary Basin (WCSB) is needed and economically feasible, and how a new west coast bitumen pipeline would compare with existing and alternative transportation options. The analysis is situated in the context of renewed policy attention to west coast export infrastructure, including the Canada–Alberta memorandum of understanding and the Government of Alberta's West Coast Oil Pipeline submission. That submission proposes a 1 million barrel per day (mb/d) pipeline to the British Columbia coast with estimated capital costs of $35.2 billion to $43.7 billion and an ownership structure led primarily by Crown entities.

Key findings

- **Supply growth does not justify major new capacity.** Alberta Energy Regulator's 2025 Alberta Energy Outlook and Canada Energy Regulator's Canada's Energy Future 2026 point to moderate WCSB production growth led mainly by optimization and expansion of existing oilsands projects rather than new greenfield development. Filling a new 1 mb/d pipeline would require stronger supply growth and renewed long-term oilsands investment than current market conditions appear to support.
- **Existing pipelines and announced expansions are adequate.** Alberta's major export pipelines provide more than 5 mb/d of capacity across westbound, southbound and eastbound routes. Announced optimization projects on Enbridge and Trans Mountain (TMX) pipelines could add more than 1 mb/d of additional nameplate capacity at lower cost and with less execution risk than a new greenfield pipeline.
- **Demand for heavy crude faces structural constraints.** Global oil demand growth is slowing across major outlooks, while demand for refined products made from heavy crude faces additional pressure. Canadian heavy crude competes in a narrower refining market, with recent TMX seaborne export data showing demand concentrated mainly in China and the United States.
- **The economic case is weakened by high tolls.** Using a negotiated toll framework, estimated committed-shipper tolls for a new west coast pipeline range from roughly C$18.66 per barrel (bbl) to C$30.51/bbl across cost scenarios, or about 1.7 to 2.7 times the current TMX 20-year committed toll. Even under an illustrative lower government-backed return, the lowest estimated toll remains materially above TMX.

- **Netback analysis does not show a clear producer benefit.** The proposed west coast pipeline produces materially lower estimated netbacks than existing routes, as higher tolls outweigh the potential value of additional tidewater access. With planned expansions expected to cost substantially less on a per-barrel basis, the cost advantage of alternative routes is likely to persist — and potentially widen — over time.
- **The Alberta submission places the risk burden on the taxpayer.** The proposed ownership structure would place close to 90% of the capital at risk with government-owned entities, with a minority private partner. If commercially competitive tolls cannot recover the full cost of the project, the gap would likely be absorbed through lower returns, longer payback periods or direct public cost.

These global market forces help explain why a private proponent did not step forward to propose a new pipeline , and why the recent proposal features substantial government backing. Under current market conditions, the primary challenge facing Alberta producers is not a lack of export capacity, but uncertainty around future demand, prices and the economics of long-term oil infrastructure. Those risks should not be shifted to taxpayers when the private sector is signalling that the project is too risky to finance on normal commercial terms.

1. Introduction

The prospect of a new bitumen pipeline to the west coast has captured significant attention over the past year, driven by the Canada–Alberta memorandum of understanding (MOU) and Alberta Premier Danielle Smith's prioritization of oil and gas expansion.[1] Supporters often frame additional export capacity as a way to diversify markets, improve producer access to global buyers and strengthen Canada's energy position. But a new greenfield pipeline would be a long-lived, capital-intensive project entering service in a global oil market facing slowing demand growth, increasing uncertainty and potential structural decline.

The risks are not limited to the pipeline itself. Filling a new export line would require sufficient oil production growth and, potentially, renewed investment in greenfield oilsands projects. For more than a decade, growth in oil production in Alberta has been driven by expansion projects and efficiency gains rather than new greenfield investment. While production is expected to grow to 2030, the current Alberta Major Projects list does not identify any new greenfield oilsands mines under development.[2] That absence is consistent with industry signals: for instance, Suncor has identified substantial growth potential within its existing asset base while stating it has "no plans for a new oilsands mine," suggesting that new greenfield oilsands investment remains unlikely under current market conditions.[3] Meanwhile, global demand for oil is expected to peak within the next five years under numerous scenarios, including from multinational oil majors.[4]

This report assesses whether additional export pipeline capacity from the Western Canadian Sedimentary Basin is likely to be economically feasible, and how a new west coast pipeline would compare with existing and alternative transportation options. It focuses on the risk to taxpayers of allocating public funds to a project defined by high cost and, so far, an absence of uptake from the pipeline and producer firms who would ordinarily bear that risk. The analysis first examines supply and demand conditions, then evaluates existing and announced pipeline capacity, and finally compares estimated tolls and producer netbacks across transportation options.

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[1] Jason Markusoff, "Danielle Smith Wants to Double Alberta Oil Production. Can She Bring Back the Boom?," *CBC News*, July 16, 2026. https://www.cbc.ca/news/canada/calgary/analysis-danielle-smith-oil-production-double-9.7271664

[2] Government of Alberta, "Major Projects," Alberta Major Projects. https://majorprojects.alberta.ca/#list/

[3] Reid Southwick, "Suncor Reveals Expansion Plans as Key Oilsands Mine Enters Its Last Decade," *Financial Post*, March 31, 2026. https://financialpost.com/commodities/energy/suncor-reveals-proposed-oilsands-expansions

[4] International Energy Forum, *IEF Outlooks Comparison Report* (2026). https://www.ief.org/events/16th-iea-ief-opec-symposium-on-energy-outlooks#report

2. West Coast Oil Pipeline submission

The Government of Alberta has proposed a new West Coast Oil Pipeline Project capable of moving 1 mb/d of crude from the Western Canadian Sedimentary Basin (WCSB) to the British Columbia coast. The project is expected to transport heavy crude oils produced from the Alberta oilsands, including both high- and low-total-acid-number bitumen blends.[5] The provincial government's submission to the Major Projects Office estimates the project's capital cost at $35.2 billion to $43.7 billion — a range that is itself wide enough to signal significant uncertainty in cost, timeline, and ultimate financing structure at this early stage. The submission targets a possible in-service date between 2032 and 2034, depending on the pace of regulatory approval and construction.

The submission argues the project "can unlock production growth, increase the oil price achieved for Alberta's oil through increased access to international markets and have positive impacts on GDP more widely," and states that "preliminary analysis indicates the Project will be able to support a competitive toll." The submission does not disclose the production growth, price, or toll assumptions underlying these claims.

A pipeline capable of moving 1 mb/d of heavy crude would require strong supply growth, durable demand for bitumen in overseas refining markets, competitive tolls, and long-term shipper commitments. The fact that the provincial government has secured only a 10% investment from a private proponent, despite significant efforts to entice participation, suggests that those conditions have not yet been met.[6] As proposed, the project would be developed and operated through a joint venture led by the Alberta Petroleum Marketing Commission and Trans Mountain Corporation — both Crown entities — alongside Pembina Pipeline Corporation as the minority private partner. This ownership structure means that close to 90% of the capital at risk would sit with government-owned entities, with the remaining share held by a single private proponent.

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[5] Government of Alberta, *West Coast Oil Pipeline Project: Submission to MPO*, 28. https://open.alberta.ca/dataset/a529e3da-6368-43d7-af43-74b1773be517/resource/6e43e4b4-3dfe-4c28-b723-116b6cab19ea/download/west-coast-oil-pipeline-project-submission-to-mpo.pdf

[6] Pembina Institute, "Full Year Without Private Sector Interest Confirms New West Coast Pipeline Is Political, Not Economic," media release, July 2, 2026. https://www.pembina.org/media-release/full-year-without-private-sector-interest-confirms-new-west-coast-pipeline-political

3. Oil markets

3.1 Supply

Alberta produces a wide range of crude oils, but much of its output comes from the oilsands and is classified as heavy crude or bitumen blends, referred to as Western Canadian Select (WCS). These heavier grades are denser and more viscous, and contain higher concentrations of sulphur than lighter crude oils, requiring specialized refining equipment such as cokers and hydrocrackers. As a result, Alberta's heavy oil is best suited for refineries that are specifically configured to process heavier feedstocks, which limits the number of markets that can efficiently accept and process these barrels.

Production growth in the WCSB is expected to be driven primarily by oilsands production. The Alberta Energy Regulator's (AER) 2025–2034 forecast notes that bitumen accounted for roughly two-thirds of Canada's oil-equivalent output in 2024 and is projected to remain the main driver of supply growth over the next decade. Production is forecast to reach 4.65 mb/d in 2034 (Figure 1). The Canadian Energy Regulator's (CER) Energy Futures framework extends this view over a longer horizon by testing production outcomes under different price, policy and demand assumptions, making it a useful complement to the AER's shorter-term, Alberta-specific outlook. Crude oil production increases for all scenarios, with longer-term pathways diverging primarily based on the crude oil price. Production ranges from 4.17 mb/d to 4.82 mb/d with the Current Measures estimate of 4.45 mb/d in 2040.

- **Oilsands:** Both AER and CER outlooks have production growth being led by oilsands production supported by optimization of existing projects. This means the production mix will become heavier over time.
- **Conventional oil:** Conventional production is expected to play a smaller and more mature role, with near-term output shaped by drilling activity, decline rates, and capital discipline.
- **Export supply:** AER projects that demand in Alberta for oil will remain stable around 590,000 b/d, leaving the majority of supply available for export.

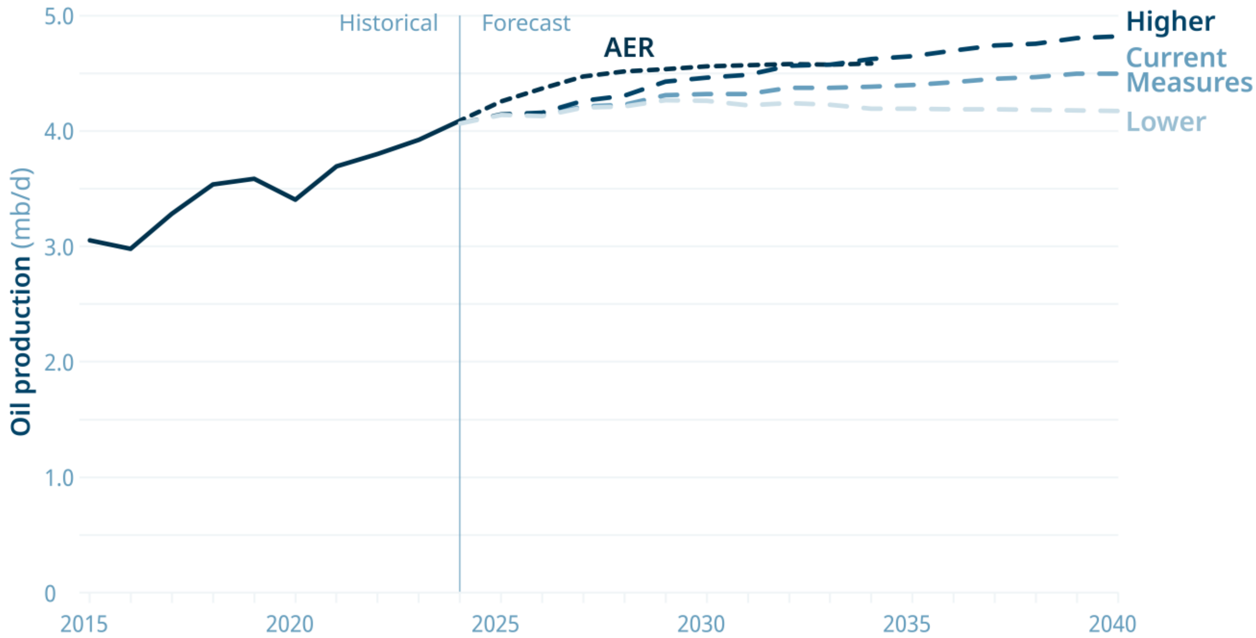

Figure 1. Alberta oil supply scenarios to 2050

Data source: CER, AER[7]

Optimization projects have been responsible for nearly all the growth in production over the past decade. This is due to the large up-front costs over multiple years and challenges to secure investment required to bring new projects online in the face of flattening demand and a weakening oil price outlook. Oil sands projects represent the most expensive sources of new supply globally, with a breakeven price of Brent crude between US$57 to US$75/bbl, well above most other major supply segments.[8] The AER estimates even higher breakeven prices, with new in situ projects requiring a WTI price of $US63/bbl while new mining projects US$80/bbl in 2024, before adjusting for inflation.[9] These costs place new greenfield expansion projects high on the marginal cost curve and would need to compete against lower-cost reinvestment in already-producing regions where fields, pipelines and market access infrastructure are already in place.

[7] CER, *Canada's Energy Future 2026: Energy Supply and Demand* (2026). https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2026/canada-energy-futures-2026.pdf

AER, *Alberta Energy Outlook 2025 (ST98)*, updated June 2025. https://www.aer.ca/data-and-performance-reports/statistical-reports/alberta-energy-outlook-st98

[8] Elliot Busby, "Shale Project Economics Still Reign Supreme as Cost of New Oil Production Rises Further," Rystad Energy, October 1, 2024. https://www.rystadenergy.com/news/upstream-breakeven-shale-oil-inflation

[9] *Alberta Energy Outlook 2025 (ST98)*

3.2 Demand

Global oil demand is entering a period of slower growth and greater uncertainty. In *Oil 2025*, the International Energy Agency (IEA) projects that demand growth through 2030 will be materially weaker than in the previous decade, reflecting softer macroeconomic conditions, rapid electric vehicle adoption, efficiency gains and structural changes in China's economy.[10] While petrochemicals, aviation and emerging-market consumption continue to support oil use, the IEA expects the centre of demand growth to shift away from China and road transport toward petrochemical feedstocks and other harder-to-electrify sectors. The *World Energy Outlook 2025* scenarios place this medium-term outlook in a broader context: under stated policies, global oil demand peaks around 2030 at roughly 102 mb/d before gradually declining, while alternative policy and technology pathways produce materially different long-term outcomes.[11] Demand plateaus or declines across several scenarios, including the IEA STEP scenario and those of major oil producers including Shell, Equinor, and Total (Figure 2).

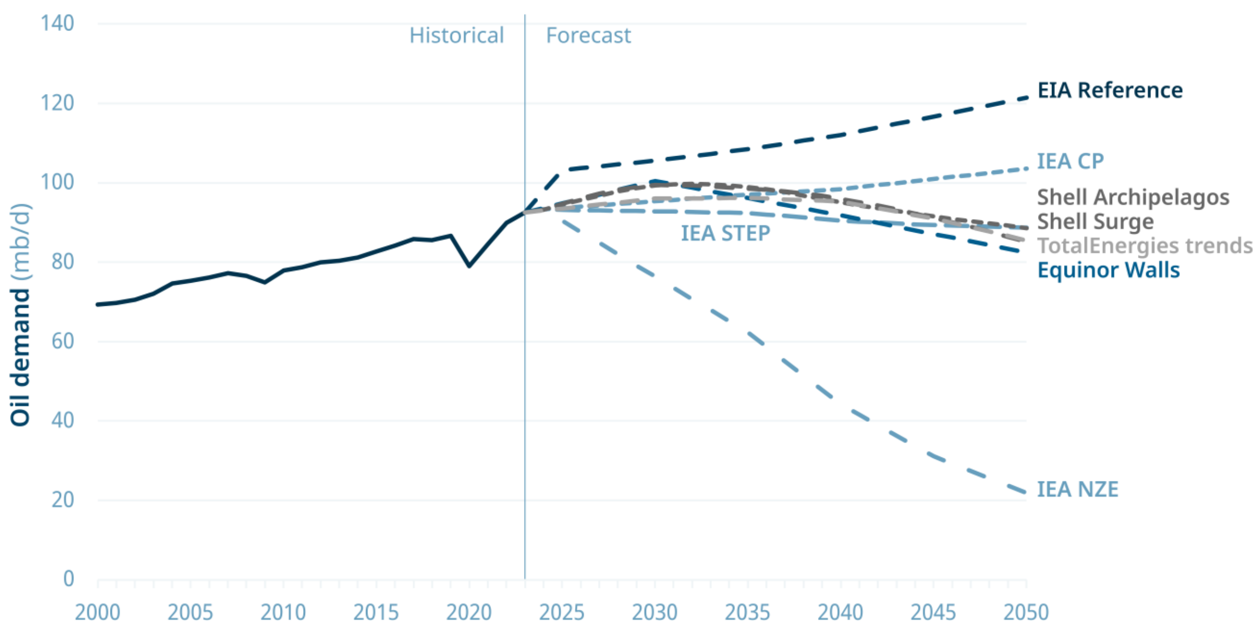

Figure 2. Oil demand scenarios through 2050

Data source: IEF[12]

[10] IEA, *Oil 2025: Analysis and forecasts to 2030* (2025), 7. https://iea.blob.core.windows.net/assets/c0087308-f434-4284-b5bb-bfaf745c81c3/Oil2025.pdf

[11] IEA, *World Energy Outlook 2025* (2025), Figure 1.28. https://www.iea.org/reports/world-energy-outlook-2025

[12] *IEF Outlooks Comparison Report* (2026).

3.2.1 Demand for bitumen

Demand for heavy crude and bitumen should be assessed separately from aggregate oil demand because WCSB barrels compete in a narrower refining market. Alberta bitumen and heavy blends are most attractive to complex refineries with coking, desulphurization and other upgrading capacity, particularly where refiners can capture value from discounted heavy crude. Globally, the regions whose refinery fleets are most built around heavy crude are India, the U.S. and Canada, and China, based on coking share of distillation capacity.[13] Historically the major importer of Canadian crude has been the U.S. as many refineries there are specifically designed to process heavy oil, primarily in the Midwest and Gulf Coast regions.[14] Outside of the U.S., China's refining system is one of the few in the world capable of absorbing heavy sour grades like WCS at the scale required.[15] India also has capacity to refine heavy sour grades, but WCSB's high total acid number and the logistical challenges facing shipments put it at a disadvantage relative to closer or cheaper heavy grades such as Venezuelan crude, when available.[16] While Japan and South Korea host globally competitive refiners that already process Venezuelan heavy crude, their heavy-conversion capacity remains well below that of the United States and China.[17] These markets generally favour lighter grades that are simpler and less costly to process, and most are still assessing the viability of Canadian barrels.[18] This has led the Government of Alberta to explore investing in Japan's refining sector in order to increase export opportunities.[19] Together, these factors leave WCS at a competitive disadvantage in these regions relative to closer or more established heavy supply.

[13] Organization of the Petroleum Exporting Countries (OPEC), *World Oil Outlook 2026*, Chapter 5, "Refining Outlook." https://publications.opec.org/woo/chapter/157/2945

[14] U.S. Energy Information Administration (EIA), "Canada's Crude Oil Has an Increasingly Significant Role in U.S. Refineries," August 1, 2024. https://www.eia.gov/todayinenergy/detail.php?id=62664

[15] Daniel Lincoln, Philippe Rheault, and Anton Malkin, "The Emergence of a New Player in the Asia-Pacific Energy Space: Two Years In, TMX and LNG Exports Are Demonstrating the Increasing Relevance of Canada," *The China Institute*, June 8, 2026. https://www.ualberta.ca/en/china-institute/policy-analysis-scholarship/policy-analysis/2026/the-emergence-of-a-new-player-in-the-asia-pacific-energy-space.html

[16] Argus Media, "Canadian TMX Crude Finds Favour in China," November 18, 2024. https://www.argusmedia.com/en/news-and-insights/latest-market-news/2629773-canadian-tmx-crude-finds-favour-in-china

[17] Rachael Gurney and Xiaoting (Maya) Liu, "Canada's Oil Exporting Future: Trans-Mountain, China, Asia, and Beyond," *Asia Pacific Foundation of Canada*, January 13, 2026. https://www.asiapacific.ca/publication/canadas-oil-exporting-future-trans-mountain-china-asia-and-beyond

[18] Tae Yeon Eom, "South Korea's Pilot Cargo of Canadian Crude Signals a New Era for Bilateral Energy Cooperation," *Open Canada*, July 7, 2025. https://opencanada.org/south-koreas-pilot-cargo-of-canadian-crude-signals-a-new-era-for-bilateral-energy-cooperation/

[19] Amanda Stephenson, "Alberta in Talks with Japan on Boosting Canadian Crude Imports," *Reuters*, June 22, 2026. https://www.reuters.com/business/energy/alberta-talks-with-japan-boosting-canadian-crude-imports-2026-06-22/

Actual export data from TMX bears this out. China accounted for 57% of TMX seaborne cargoes, with the U.S. receiving 38%. Meanwhile just 4 cargoes (1%) have gone to India/Brunei, with other Asian countries (Korea, Japan and Singapore) receiving 20 cargoes (4%) (Figure 3). This data reflects both the competitiveness of Canadian crude against Latin American exports on the global market but also the refining capacity constraints in markets outside of China and the U.S.

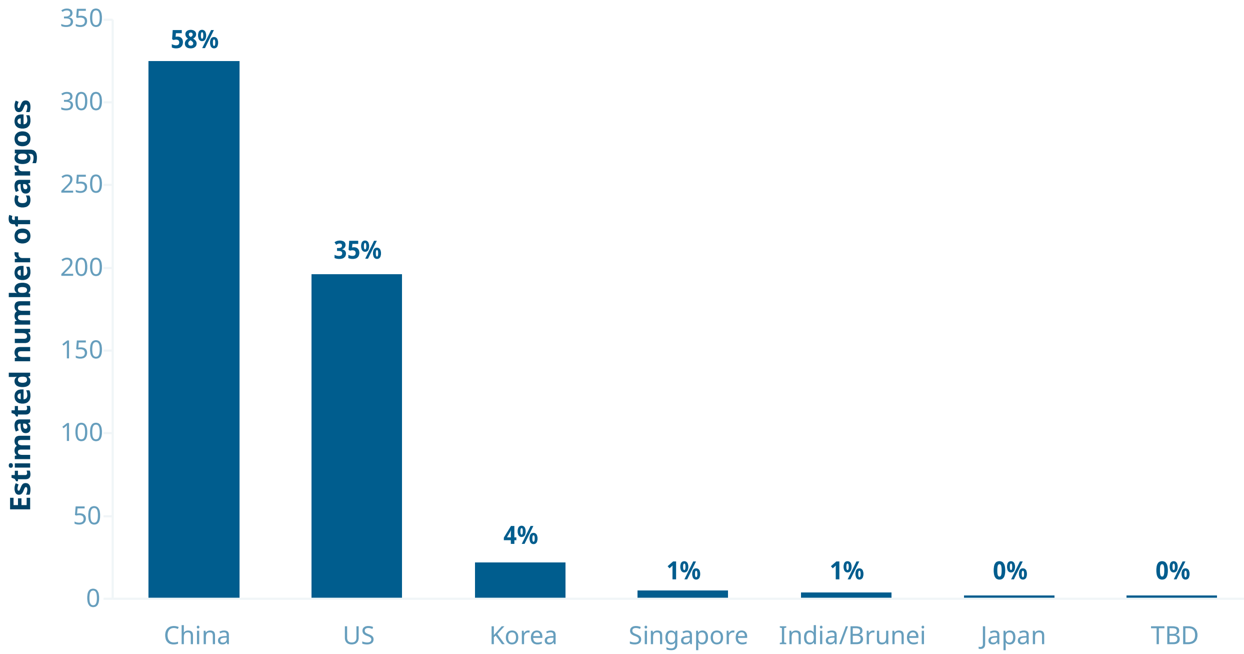

Figure 3. Estimated final cargo destinations from TMX (May 2024 to April 2026)

Data source: Trans Mountain Corporation[20]

3.2.2 Refining capacity

As noted above, Alberta bitumen is a very specific product and therefore can only be refined in areas with facilities designed to take it. It is thus appropriate to look at forecasts for refining capacity as a proxy for potential demand for Canadian crude. *Oil 2025* points to a structural headwind for heavy crude that is more pronounced than the aggregate demand picture suggests.[21] While global oil demand is projected to grow just 2.5 mb/d between 2024 and 2030 before plateauing near 105.5 mb/d, demand for refined *products* peaks earlier — around 2027 at roughly 86 mb/d — and declines thereafter. Critically for Alberta, almost 90% of the remaining growth comes from non-refined products including natural gas liquids and petrochemical feedstocks (LPG, ethane, naphtha), rather than the gasoline and diesel that heavy sour crude is refined into through coking.

[20] Trans Mountain Corporation, *Corporate Update: Q1 2026* (2026). https://docs.transmountain.com/Corporate-Reports/Q1-2026-Corporate-Presentation_EN_V2.pdf

[21] IEA, *Oil 2025*. 86

Although heavy oil can feed petrochemical production, it is a costlier and more processing-intensive route than using lighter feedstocks such as ethane, LPG and naphtha, and requires specialized deep-conversion capacity like coking and hydrocracking. As demand for transport fuels peaks and declines after 2027, the product pool that heavy barrels serve begins to shrink, even as lighter, feedstock-oriented demand continues to rise.

At the same time, non-OPEC+ supply growth — led by the U.S., Brazil, Guyana and Canada itself — is expected to more than cover demand growth to 2030, keeping global markets well supplied. For Alberta crude, this means heavy barrels will increasingly have to compete on a delivered-cost basis in a shrinking refinery market, making transportation costs a key determinant of competitiveness. Looking further to 2050 we see the demand for refined products continue to decline with capacity also declining in response to market conditions (Figure 4).

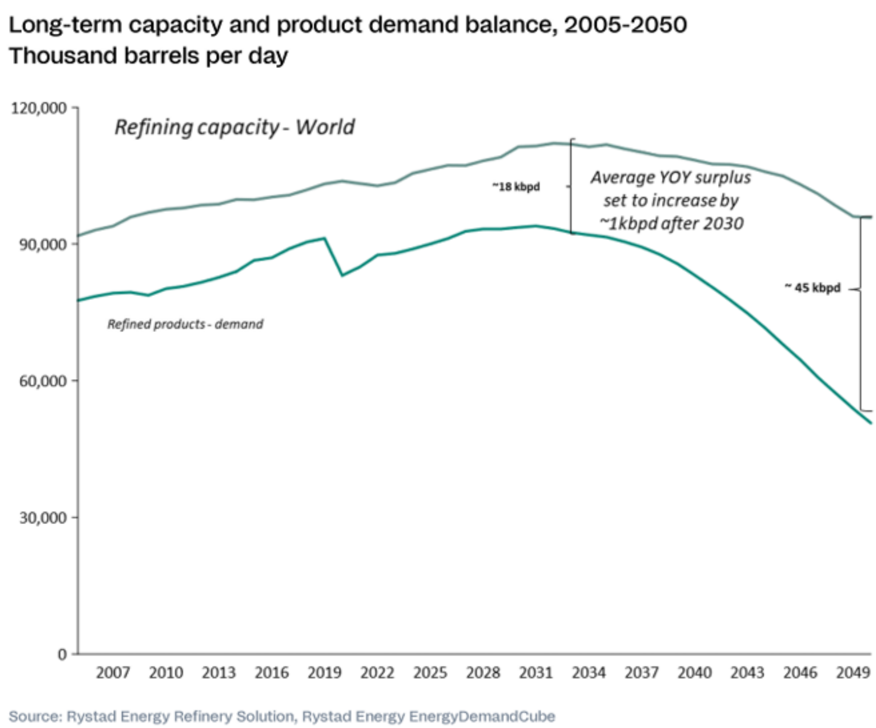

Figure 4. Long-term capacity and product demand balance

Source: Rystad Energy[22]

[22] Rystad Energy, *The Future of Refining: Global Shifts and Strategic Outlook Toward 2030* (2025). https://www.rystadenergy.com/insights/the-future-of-refining-global-shifts-and-strategic-outlook-toward-2030

4. Pipeline capacity and costs

4.1 Existing and proposed capacity

Alberta's crude oil exports are served by three major pipeline systems and three smaller ones that transport production from the Edmonton and Hardisty hubs to external markets (Table 1). The Enbridge Mainline is the largest corridor, moving the majority of volumes east and south into the U.S. Midwest and eastern Canada, while the Keystone Pipeline carries significant volumes south from Hardisty to key U.S. refining centers, including the Gulf Coast.

Table 1. Alberta export pipeline capacity

Pipeline	Operator	Design capacity (b/d)
Enbridge Canadian Mainline	Enbridge Inc.	3,350,000
TMX	Trans Mountain Corporation	890,000
Keystone	TC Energy	610,000
Express	Enbridge Inc.	310,000
Rangeland	Plains Midstream Canada	100,000
Milk River	Inter Pipeline	98,000
Total		**5,358,000**

Data source: AER[23]

To the west, TMX (expanded in 2024) provides Alberta's only direct access to tidewater, enabling exports to Pacific and overseas markets. Smaller lines like the Express pipeline and cross-border connections into Montana provide additional capacity, but overall the export system is highly concentrated in these three core routes. These pipelines have a combined export capacity of just over 5 mb/d. Total system utilization has averaged 93% since 2024 (Figure 5).

[23] AER, "Pipelines", Table S8.2. https://www.aer.ca/data-and-performance-reports/statistical-reports/alberta-energy-outlook-st98/pipelines-and-other-infrastructure/pipelines

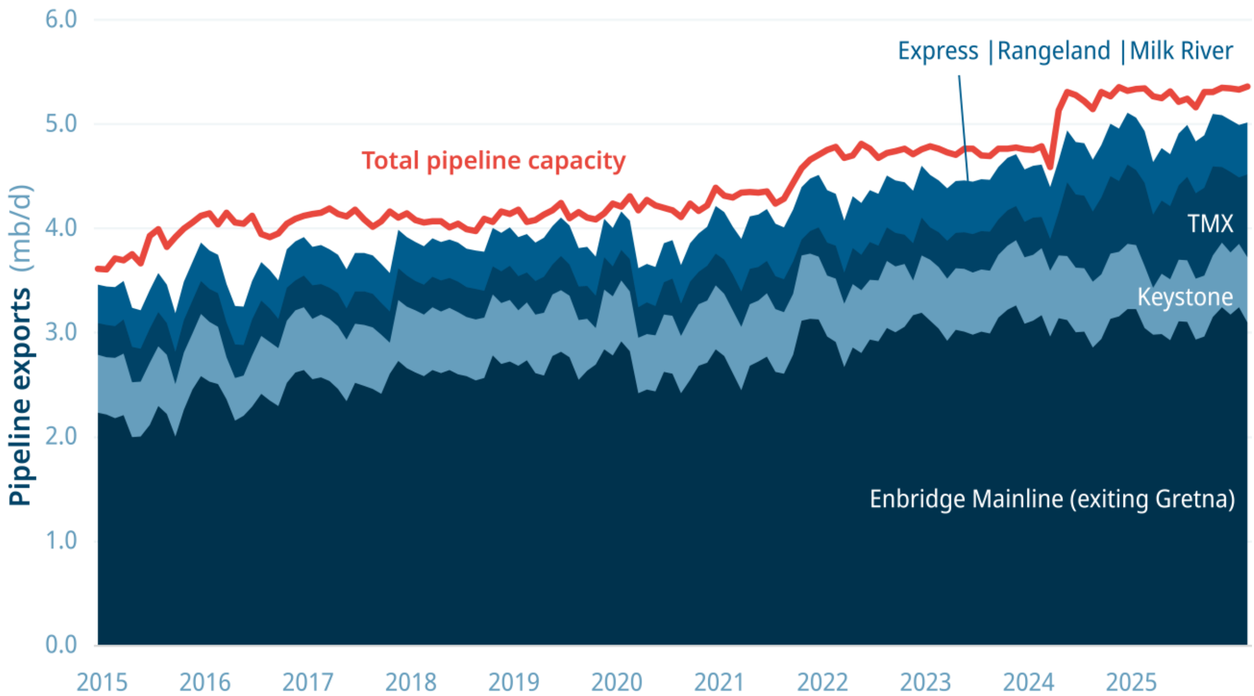

Figure 5. Alberta pipeline throughput and capacity

Data source: CER[24]

4.2 Supply-capacity balance

As existing pipelines approach their nameplate capacity, operators have proposed several projects to expand throughput on existing systems, particularly the Enbridge Mainline and TMX (Table 2).

Table 2. Pipeline expansion plans and proposals

Project	Proposed expansion capacity (b/d)	Projected completion
Enbridge Mainline Optimization 1	180,000	2027/28
Enbridge Mainline Optimization 2	250,000	2028
TMX Drag Reducing Agent Project	90,000	2027
TMX Mainline Optimization Project	210,000	2028
Subtotal (expansions)	**730,000**	

[24] CER, "Crude Oil and Liquids – Pipeline Flow and Capacity." https://www.cer-rec.gc.ca/en/data-analysis/facilities-we-regulate/look-pipeline-flow-capacity/crude-oil-liquids-pipeline-flow-capacity.html

Keystone XL/Bridger Phase 1	550,000	TBD
Keystone XL/Bridger Phase 2	550,000	TBD
West Coast Oil Pipeline proposal	1,000,000	TBD
Total (expansions plus proposed new lines)	**2,830,000**	

Data source: Company reports[25]

Together, announced optimizations represent 730,000 b/d of nameplate capacity additions. This would be achieved by improving the efficiency of pipelines already in the ground through drag-reducing agents and additional pump stations (and, for the Mainline, terminal enhancements). It is worth noting that these expansions are far cheaper and faster than the construction of a new pipeline. Further these expansions provide ample capacity based on the most optimistic scenario for oil production.

Planned expansions to existing pipeline systems are sufficient to accommodate expected Alberta export volumes. Figure 6 compares export capacity with crude oil available for export from western Canada, as reported in the CER Energy Futures report.[26] Export capacity is based on 2026 reported nameplate capacity and increases to 2030 using the planned optimizations shown in Table 2, with all pipelines assumed to operate at a maximum of 98% to reflect real-world conditions. Optimizations of existing pipelines pushes nameplate capacity to roughly 6 mb/d by 2030. Under the Current Measures scenario, oil available for export reaches at most 92% of export capacity. Under the Higher scenario, export volumes exceed capacity only in the late 2040s; however, that pathway is unlikely as it depends on a sustained high-price environment, where Brent prices average US$95/bbl. It also suggests roughly 900 kb/d of additional production relative to 2026, implying a level of sustained upstream investment that appears out of step with current industry signals. Even if additional capacity were ultimately required, lower-cost private-sector expansions, such as the Prairies Connector or further Mainline optimizations, could add capacity at materially lower cost than a new greenfield west coast pipeline.

[25] Enbridge Inc., "Mainline Optimization." https://www.enbridge.com/projects-and-infrastructure/projects/mainline-optimization

Trans Mountain Corporation, "Drag Reducing Agent." https://engage.transmountain.com/drag-reducing-agent

Trans Mountain Corporation, "Mainline Optimization Project." https://engage.transmountain.com/mainline-optimization

Bridger Pipeline Expansion, LLC, *Bridger Pipeline Expansion: Montana Major Facility Siting Act Application for a Certificate of Compliance* (March 26, 2026), 2. https://deq.mt.gov/files/Energy/MFSA/Bridger/Bridger%20MFSA%20App_2026-0326.pdf

[26] *Canada's Energy Future 2026*, 98.

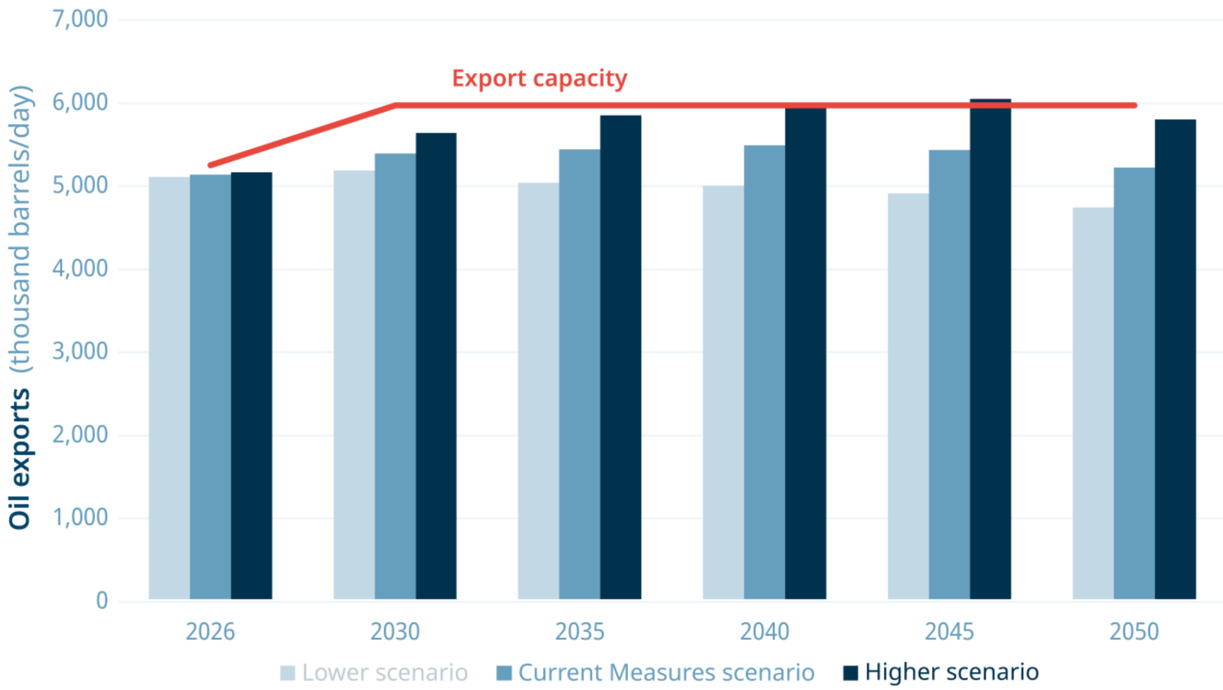

Figure 6. Projected total export capacity, including proposed expansions, compared to total supply available to export from western Canada

Note: Crude oil available for export is defined as oil production in western Canada less crude oil used in refineries in Alberta and Saskatchewan. This also includes diluent blended with both bitumen and heavy crude oil for transport.

Data source: CER, Pembina calculations[27]

Adding substantial additional capacity risks overbuilding the system. When pipelines run under capacity, tolls climb and shipping costs rise across the network, which can undermine the economics of existing infrastructure such as the Enbridge Mainline and ultimately threaten the viability of the very assets already in the ground.[28] Transportation cost comparison

In order to assess the economic viability of a new west coast pipeline, we have estimated the tolls required to recover construction costs and conducted a netback analysis to compare transportation options for Western Canadian heavy crude. All calculations and assumptions are outlined in Appendix A.

Across the major pipeline systems, three structural variables consistently drive toll differences:

- **Committed vs. uncommitted (spot) shipping**: Uncommitted/spot shippers pay a premium over committed shippers. On Keystone, the maximum uncommitted toll is capped at 120% of the relevant committed toll; spot tolls on TMX have risen further as system utilization has tightened.

[27] CER, *Canada's Energy Future 2026*.

[28] Leach, *Pipe Dream or Panacea?*, 21.

- **Contract term**: Longer commitments earn lower tolls. On TMX, 20-year committed service tolls are lower than 15-year committed tolls; the same term discount structure applies on Keystone (10-year versus 20-year toll schedules).
- **Volume commitment**: Shippers committing to 75,000 b/d or more receive preferential tolls on TMX relative to those shipping smaller volumes.

This matters directly for a new pipeline's economics: a project can only achieve its lowest illustrative tolls if it secures a high proportion of long-term, large-volume committed shippers at financial close.

4.2.1 Toll estimate

We have estimated the tolls required to cover the costs of a proposed west coast pipeline following the negotiated toll settlement structure, such as used on TMX: shippers and the pipeline owner negotiate fixed long-term tolls that are designed to recover the owner's capital and operating costs, plus a target rate of return. This method is also appropriate for assessing a project that has not yet reached a financing decision. A pipeline of this scale cannot be built without securing long-term shipper commitments sufficient to give a developer confidence in recovering its investment; the toll required to secure those commitments is therefore the toll that determines whether the project can proceed at all, not simply what it would cost to operate once built. A negotiated toll framework therefore provides a practical way to test how tolls would vary under different cost and utilization assumptions, while reflecting the revenue certainty that would be needed to support project development.

For the purposes of this analysis, we have used three cost scenarios; low, high, and TMX cost equivalent. Low- and high-cost scenarios are based on the Government of Alberta's submission to the Major Projects Office.[29] These scenarios have a cost per barrel of 27% to 41% lower than the cost to build TMX, which is an optimistic assumption given inflation and the size of the proposed pipeline. Therefore, we have also analyzed a third cost scenario based on TMX's approximate cost. The estimated per b/d cost of TMX is $59,800, giving a total estimated capital cost for a new pipeline with a capacity of 1 million b/d of $59.8 billion.[30] Operating costs are kept constant across scenarios as these are independent from the cost to build. We use a 13.5% unlevered internal rate of return (IRR)[31] based on Kinder Morgan's initial target of 12% to 15% (see Section A.1 for details).

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[29] Alberta, *West Coast Oil Pipeline Project: Submission to MPO*, 39.

[30] This represents the total costs of construction divided by the numbers of barrels per day of capacity. It normalizes constructions costs by the capacity of the pipeline.

[31] Unlevered internal rate of return (IRR) measures the project-level return before accounting for financing structure or debt costs. It reflects the return required on the underlying asset itself, independent of how the project is funded.

We estimate tolls on the pipeline to have a range of C$18.66 to over C$30 per barrel, increasing by 2.5% every year (Table 3). These tolls range between 1.67-2.74 times more than what is currently charged on TMX.

Table 3. Estimated committed shipper tolls

Scenario	Low	High	TMX Costs
Project cost (billions)	$35.20	$43.70	$59.80
Toll 13.5% IRR (C$ per barrel)	$18.66	$22.75	$30.51
Relative to TMX 20yr contract	1.67x	2.04x	2.74x
Sensitivity analysis			
Toll 8% IRR (C$ per barrel)	$13.07	$15.81	$21.02
Relative to TMX 20yr contract	1.17x	1.42x	1.89x

These estimates reflect a private sector target rate of return. However, the proposal as currently structured envisions the pipeline being majority government-financed, with the Alberta Petroleum Marketing Commission and Trans Mountain Corporation together holding approximately 90% ownership. This ownership structure may justify a lower target return than would be required by a private developer. Government-backed entities typically access capital at a lower cost than private sponsors, and a Crown-owned or Crown-backed project may not need to compensate investors for the same risk premium a private developer would demand, particularly where the sponsor's objectives extend beyond commercial return alone. As a lower-bound illustrative sensitivity, we also test an 8% rate, used by the Parliamentary Budget Officer in its analysis of TMX's commercial viability. As this rate reflects the risk of an already-built, operating asset rather than a new project still facing construction risk, it likely understates the return a developer would require for the proposed pipeline, but it is useful in illustrating a plausible lower bound. At this rate tolls are C$13.07.00 to C$21.02 per barrel, 17% higher than TMX’s current tolls in the lowest cost scenario.

4.2.2 Netback calculation

The netback is the value a producer receives after deducting the costs required to transport crude from the production-area pricing point to a destination market. Comparing netbacks across pipeline options therefore helps assess whether a proposed west coast pipeline would improve producer returns relative to existing routes such as TMX, Enbridge and Keystone. A higher netback indicates that a transportation option leaves more value for the producer, while a lower netback suggests that higher tolls, longer routes or weaker market pricing reduce the economic return.

In this analysis, indicative route netbacks are calculated by deducting the applicable all-in pipeline transportation cost from an estimated price at the relevant delivery point. WCS Hardisty is used as the Alberta benchmark and to illustrate the potential market-value uplift associated with reaching each destination. The analysis estimates WCS Houston using differentials to WTI Houston. In the absence of a publicly accessible WCS Vancouver assessment, it uses High-TAN Vancouver as a proxy for the Vancouver value of Canadian heavy crude.[32] Netbacks are calculated as the estimated destination price less the applicable route cost. As we have measured the price at Houston and Vancouver, respectively, the analysis does not include ocean freight to China or other end markets (see Section A.2 for details).

Table 4. Netback comparison (USD$/bbl)[33]

	USGC via Enbridge Mainline	TMX	Proposed Pipeline	
			13.5% IRR	8% IRR
Estimated destination price	$61.25	$59.82	$59.82	$59.82
Uncommitted toll, heavy crude	$9.86	$10.06	$19.52	$13.57
Netback	$51.39	$49.76	$40.30	$46.25

Using uncommitted toll estimates for both IRR scenarios at a construction cost of $43 billion yields a significantly lower netback than existing lines (Table 4).[34] We find that the U.S. Gulf Coast (USGC) provides the highest netback to producers as estimated WCS Houston averaged US$1.43/bbl above High-TAN Vancouver benchmark in 2025 while also being the lower cost shipping option. This relationship may differ in periods of tighter export capacity or wider Canadian-heavy-crude differentials

This finding is consistent with the regulatory record in CER Proceedings regarding Trans Mountain Pipeline Toll Dispute. Independent market evidence filed in that proceeding similarly concludes that Enbridge, rather than TMX, has served as the price-setting route for WCS since

32 High-TAN Vancouver is not treated as an identical WCS assessment; results should therefore be interpreted as indicative comparative route economics rather than a grade-for-grade WCS netback analysis.

33 The USGC destination price is estimated WCS Houston. Vancouver prices use High-TAN Vancouver as a proxy for the Vancouver value of Canadian heavy crude. Results are indicative and depend on tolls being comparable, all-in costs to the applicable assessed delivery points. Uncommitted tolls are used to represent an incremental shipper without long-term contracted capacity.

34 Uncommitted tolls are assumed to be 20% higher than committed tolls as is the case on TMX.

mid-2024.[35] This is reinforced by the fact that Enbridge's system has continued to run at full capacity while a share of TMX's uncommitted capacity historically remained unused, which points to the USGC route being the more cost-competitive option for shippers.[36] Because TMX's toll is set to rise faster over time than Enbridge's, and because Enbridge's next planned expansion is expected to cost substantially less on a per-barrel basis than TMX did, the cost advantage of the USGC route is likely to persist, and potentially widen, rather than narrow going forward.[37]

4.2.3 Normalized cost comparison

A normalized cost comparison expresses each pipeline toll on a common dollar-per-thousand-kilometre basis, which helps separate the effect of distance from the underlying cost of using each transportation option. This is useful because pipelines serve different routes and markets. Longer systems such as Enbridge and Keystone may have higher total tolls, but they also move crude much farther, while shorter west coast routes can appear less costly in absolute terms even when they are more expensive per kilometre. On this basis, the proposed pipeline is almost double TMX and close to four times the cost of Enbridge and Keystone (Table 5). TMX tolls are also notably higher than the Enbridge and Keystone systems, reflecting both the high cost of construction and the market premium associated with direct tidewater access. The proposed pipeline's higher normalized cost therefore indicates that it would need to deliver a substantial market-access benefit to offset its higher transportation cost. The premium associated with direct tidewater access is likely to be eroded with additional access as well.

[35] Canadian Natural Resources Limited, *Response to Canada Energy Regulator Information Request No. 1*, in *Trans Mountain Pipeline ULC Application for Interim Commencement Date Tolls and Other Matters Related to the Transportation of Petroleum on the Expanded Trans Mountain Pipeline System*, CER File OF-Tolls-Group1-T260-2023-03 01, filing in Canada Energy Regulator File 3430899, document C34526-2, 24. https://docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92835/552980/4301738/4369664/4369670/4400304/4572059/C34526-2_Canadian_Natural_Resources_Limited_-_Canadian_Natural_Response_to_CER_IR_No.1-_A9I6T3.pdf?nodeid=4572233&vernum=-2

[36] *Response to Canada Energy Regulator Information Request No. 1*, 81.

[37] *Response to Canada Energy Regulator Information Request No. 1*, 97.

Table 5. Normalized tolls

Pipeline*	Origin	Delivery	Toll (US$ per barrel)	Distance	Normalized toll (US$ per 1,000 km)
Enbridge[38]	Edmonton	Texas	$9.05	3,046	$2.97
Keystone[39]	Hardisty	Port Arthur	$8.95	3,456	$2.59
TMX[40]	Edmonton	Westridge	$7.97	1,180	$6.76
Proposed West Coast Oil Pipeline	Edmonton	TBD	$16.28	1,211	$13.44

* All pipelines shipping heavy crude petroleum on 20-year committed contracts

[38] Enbridge Pipelines, *CER No. 602: Flanagan South Pipeline System Tariff* (effective July 1, 2026), 6. https://www.enbridge.com/~/media/Enb/Documents/Tariffs/2026/FSP-FERC-3580-LKHD-CER-602.pdf?rev=7a9d1b49104248f8ba68eb37162b2139&hash=CC07DD0DBC2F1EBBC7DE303F3618CBCC

[39] Calculated using a combination of CER reported tolls to the international border at Gretna and FERC reported South Bow tolls to Port Arthur: South Bow, *F.E.R.C. No. 6.113.0: Local Pipeline Tariff Containing Rates Applying to the Transportation of Petroleum from the International Boundary with Canada at or near Haskett, Manitoba to Points in Illinois, Oklahoma and Texas* (effective July 1, 2026). https://www.southbow.com/wp-content/uploads/2026/05/FERC-6.113.0-South-Bow-Rate-Schedule.pdf

[40] CER, "Trans Mountain System," Pipeline Profile, section updated April 2026. https://apps.cer-rec.gc.ca/PPS/en/pipeline-profiles/trans-mountain-expanded-system

5. Conclusion

Analysis of Alberta production forecasts, global oil demand scenarios, export infrastructure and transportation economics does not support the case for a new west coast bitumen pipeline at this time. Both the AER and CER project moderate production growth over the coming decade, with increases driven primarily by optimization of existing oilsands facilities rather than the development of new greenfield projects. Even under higher production scenarios, existing pipeline infrastructure and announced expansions appear sufficient to accommodate anticipated export volumes.

At the same time, the global oil demand outlook is increasingly uncertain. Several major outlooks project slowing demand growth and eventual plateauing or decline in oil consumption, while demand for refined products produced from heavy crude faces additional pressure. Although TMX has improved access to offshore markets, export data suggest that demand for Canadian heavy crude remains concentrated in a limited number of regions, particularly China and the United States.

The economic case for a new export pipeline is further weakened by transportation costs. Estimated tolls for a new west coast pipeline are substantially higher than those of existing systems and would require strong utilization and long-term shipping commitments to remain competitive. Even at a lowered target return reflecting the project's majority government ownership, our estimated toll remains significantly higher than tolls on comparable pipelines, including TMX's own committed toll. Closing this gap would likely require charging shippers a toll below full cost recovery, with the shortfall absorbed through an extended payback period, a lower return to government sponsors, or an outright cost to taxpayers. This mirrors TMX where its current tolls reflect a negotiated settlement that caps shippers' exposure to cost overruns, leaving 70% of the cost overruns to be absorbed by Trans Mountain Corporation.[41]

Taken together, the evidence suggests that incremental expansions of existing pipeline systems provide a lower-cost and lower-risk approach to accommodating future production growth. Under current market conditions, the primary challenge facing Alberta producers is not a lack of export capacity, but rather uncertainty surrounding future oil demand, prices, and the willingness of industry participants to commit capital to large-scale long-term infrastructure investments. Those risks should not be shifted to taxpayers when private-sector participants have not demonstrated sufficient willingness to finance the project on commercial terms.

[41] Amanda Stephenson, "Trans Mountain Pipeline, Canada Oil Shippers in Talks to Resolve Shipping Cost Dispute," *The Globe and Mail,* October 22, 2025. https://www.theglobeandmail.com/business/industry-news/energy-and-resources/article-trans-mountain-in-talks-with-canadian-oil-shippers-to-resolve-toll/

Appendix A. Toll and netback calculations

A.1 Toll model

Pipeline tolls were estimated using a negotiated settlement approach. Major crude oil pipelines in North America are typically financed through long-term shipping commitments, with tolls established to recover capital costs, operating expenses, financing costs and an agreed return on investment over the life of the asset. A negotiated settlement framework therefore provides a reasonable approximation of the toll structure that would likely be required for a new greenfield export pipeline. This approach is also consistent with the tolling arrangements used for TMX, where committed shippers entered into long-term transportation service agreements and negotiated toll structures that formed the basis of regulatory filings and cost recovery.

A.1.1 Toll calculation

Assumptions	Value	Description
Annual Opex, Year 1 (C$)	$466 million	Based on TMX 2025 year-end financial statements (pipeline operating costs & administration). These costs are inflated at 2% to 2026 and a 10% premium is applied to reflect size of pipeline and increasing pipeline operating costs on TMX.[42]
Stated capacity (b/d)	1,000,000	From submission to MPO[43]
Design utilization	90%	
Operating days per year	365	
Contract term (years)	20	
% capacity under committed contracts	80%	
Opex escalation rate	2.0%	Costs increased at the rate of inflation

[42] Trans Mountain Corporation, *Management Report for the Year Ended December 31, 2025* (2026), 6. https://docs.transmountain.com/Corporate-Reports/TMC-12.31.25-Management-Report-Final_EN.pdf

[43] Alberta, *West Coast Oil Pipeline Project: Submission to MPO*. 2.

Target unlevered pre-tax rate of return	13.5%	Previous regulatory filings for TMX by Kinder Morgen show 12-15% IRR. We have chosen the middle of this range.[44]
Annual toll escalation rate (fixed toll, after year 1)	2.5%	Follows toll escalation for TMX

A.2 Netback model

We estimate WCS Houston and WCS Hardisty prices using Argus differentials to WTI Houston published in the IEA Monthly Oil Market Report.[45] As a public proxy for the Vancouver value of Canadian heavy crude, we use the Argus High-TAN Vancouver differential to ICE Brent, also published in the IEA reports. High-TAN Vancouver is treated as a Vancouver heavy-crude proxy, not as an identical WCS assessment.[46]

We calculate the indicative netback by deducting the applicable pipeline toll from the estimated destination price. We use the uncommitted toll because it is the most relevant tariff for an incremental shipper without a long-term transportation commitment. This is intended to approximate the economics facing a marginal barrel, rather than the average cost faced by contracted shippers.

A.2.1 Prices

Date	WTI Houston	ICE Brent
1/1/2025	$76.29	$78.38
2/1/2025	$72.75	$74.86
3/1/2025	$69.83	$71.47
4/1/2025	$64.32	$66.46
5/1/2025	$61.85	$64.01

[44] Trans Mountain, *Responses to Canadian Association of Petroleum Producers (CAPP) Information Request No. 1*, Exhibit B16-6, National Energy Board Hearing Order RH-001-2012, January 10, 2013, 5. https://docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92835/552980/954292/828580/865601/902040/B16-6_-Revised_Jan_10_2013_CAPP_IR_Response-_A3E7F4.pdf?nodeid=902044&vernum=-2

[45] International Energy Agency (IEA), *Oil Market Report –August 2026*. https://www.iea.org/reports/oil-market-report-august-2026

[46] This follows the methodology by the Canadian Energy Research Institute: Andrea Orellana and Dinara Millington, *Heavy Barrel Competition in the US Gulf Coast: Can Canadian Heavy Barrels Compete?* (Canadian Energy Research Institute, May 2016). https://natural-resources.canada.ca/sites/nrcan/files/energy/energy-resources/CERI_Study_157_Final_Report.pdf

Date	WTI Houston	ICE Brent
6/1/2025	$67.93	$69.80
7/1/2025	$68.00	$69.55
8/1/2025	$65.13	$67.26
9/1/2025	$65.02	$67.58
10/1/2025	$61.11	$63.96
11/1/2025	$60.33	$63.66
12/1/2025	$61.54	$63.66

A.2.2 Estimated prices at destination (US $)

Date	WCS	Estimated Van FOB	Estimated WCS Houston
1/1/2025	$62.20	$68.22	$70.27
2/1/2025	$58.91	$65.33	$68.03
3/1/2025	$58.15	$62.06	$65.12
4/1/2025	$53.80	$58.06	$59.79
5/1/2025	$51.60	$56.01	$57.51
6/1/2025	$56.53	$61.83	$63.72
7/1/2025	$55.51	$62.02	$63.79
8/1/2025	$51.86	$58.78	$60.08
9/1/2025	$53.11	$59.03	$59.75
10/1/2025	$49.26	$57.80	$56.49
11/1/2025	$48.08	$54.47	$55.34
12/1/2025	$48.23	$54.22	$55.12

Photo: Roberta Franchuk, Pembina Institute