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Cash flow modeling shows carbon capture and storage can help meet climate goals

Technical backgrounder

by Scott MacDougall, Jonathan Arnold, Janetta McKenzie

Summary

This report gives more details on the analysis discussed in our recent article in Policy Options and builds on our previous report analyzing the policy landscape for CCS in Canada's oilsands. We find that existing and announced incentives bolstered the expected strong price signal from planned carbon pricing increases to incentivize carbon capture in the oilsands. We accounted for incentives from the CCS investment tax credit, offsets/compliance credits from carbon pricing, contract for difference, and Clean Fuel Regulations.

We developed a cash flow model to assess the economic viability of CCS projects under existing and announced policies and incentives in Alberta. We examined installing CCS on two typical oilsands facilities: an in situ facility and a mine with an upgrader. The analysis shows that these projects are financially feasible under a range of potential costs and incentives, assuming a consistent carbon price that reaches $170 per tonne in 2030.

In our model, both projects would break even below the headline carbon price in 2030, and with expected incentives:

- A 1-megatonne (Mt) CCS project at the in situ facility reduces emissions by 63% and achieves internal rates of return of 11-33%
- A 1-Mt CCS project at a hydrogen plant at an oilsands mine reduces emissions by 12% and achieves internal rates of return of 8-16%

Our analysis includes the cost of capturing the CO2, the cost of transporting it using Pathways' proposed pipeline from Fort McMurray to Cold Lake, and the cost of storing the CO2. In the oilsands context, CCS is not only an investment in competitiveness and regulatory compliance, but it can also offer positive returns for what is the cost of doing business in the low-carbon economy. For private operators, the results signal that substantial CCS build-out in the oilsands is cost effective. For policymakers, the results signal the importance of solidifying keystone policies, while also ensuring that oilsands CCS is not over-incentivized by public funds.

Introduction

Getting Canada's oilsands on a net zero pathway requires companies to make timely, transformative investments. Companies representing 95% of oilsands production have committed to achieving net zero (upstream) emissions by mid-century — efforts that will be essential for complying with the federal government's forthcoming cap on oil and gas emissions. Carbon capture and storage (CCS) could be a significant technology to achieve these ambitious targets.

Yet the economic viability of CCS has been questioned, and for different reasons.

On one hand, industry claims that more public support is necessary to make these projects economic,[1] despite significant financial incentives through existing and proposed government policy.[2] On the other hand, providing any level of public support to the oil and gas sector could "lock in" carbon emissions and make it harder and more expensive to reduce emissions in the future. And with record profits in the oilsands, there is a bigger question about whether companies should pay their own way, treating CCS as a cost of doing business in a global context focused on tackling the climate crisis.[3]

Overshadowing the entire debate is a lack of public information and data about the industry's proposed projects that prevents a clear analysis of the tradeoffs at stake. To shed light on how public incentives affect the economics of oilsands CCS projects, we developed a cash flow model (using publicly available information) to estimate the viability of retrofitting two hypothetical oilsands facilities with CCS. This report includes the discussion of methodologies, modeling assumptions, and results. A higher-level overview of our findings is published in Policy Options.[4] This builds on our previous work analyzing the policy landscape for CCS in Canada's oilsands.[5]

[1] Amanda Stephenson, "Oilsands group pledges to spend $16.5B on carbon capture project by 2030," *Toronto Star,* October 14, 2022. https://www.thestar.com/business/2022/10/14/oilsands-group-pledges-to-spend-165b-on-carbon-capture-project-by-2030.html

[2] Robert Tuttle and Brian Platt, "Trudeau is betting $12.4 billion on a plan to clean up the world's dirtiest oil." *Bloomberg News*, June 5, 2023. https://www.bnnbloomberg.ca/trudeau-is-betting-12-4-billion-on-a-plan-to-clean-up-the-world-s-dirtiest-oil-1.1928875

[3] Jan Gorski and Eyab Al-Aini, *Waiting to Launch: The gap between Canadian oilsands companies' climate pledges and actions*, (Pembina Institute, 2022). https://www.pembina.org/pub/oilsands-waiting-launch

[4] Scott MacDougall, Jonathan Arnold, Janetta McKenzie, "Cash-flow modeling shows carbon capture and storage can help meet climate goals," *Policy Options*, July 10, 2023. https://policyoptions.irpp.org/magazines/july-2023/carbon-capture-goals/https://policyoptions.irpp.org/magazines/july-2023/carbon-capture-goals/

[5] Janetta McKenzie, Scott MacDougall, "Comparing Canadian and American Financial Incentives for CCUS in the Oil Sector (Pembina Institute, 2023). https://www.pembina.org/pub/comparing-canadian-and-american-financial-incentives-ccus-oil-sector

Scope of work

Our analysis assesses the cash flows associated with deploying CCS at two generalized oilsands projects, using publicly available data. We modeled capital and operating costs for a hypothetical 1-Mt CCS project installed at a **gas-fired power plant at an in situ facility** and at a **hydrogen plant at hydrogen plant at an integrated oilsands mine**. This work does not include cash flows outside of the CCS project (e.g., revenues from oil production) and focused on earnings before interest, taxes and royalties, depreciation and amortization (EBITDA).

This scope provides clarity on the economics of CCS at generalized oilsands sites to help shed some light on the business case for oilsands CCS. When combined with data from Rystad on oilsands production costs, it also illustrates how CCS investments at oilsands facilities are impacted by transition risk ("having stagnant or negative market growth potential in a global low-carbon transition"[6]).

#1: Deploying CCS on oilsands facilities can improve the industry's carbon competitiveness but does not eliminate transition risk

Scaling up CCS could significantly cut emissions and improve an oilsands facility's carbon competitiveness. As the transition to a global low-carbon economy accelerates, oil demand is expected to decline significantly. In that shrinking market, oil producers with the lowest costs and carbon intensities will be more competitive, so will have lower risk of their facilities becoming stranded (i.e., lower transition risk). At present, however, oilsands facilities generally have higher costs and carbon intensities relative to global averages: some facilities perform only slightly worse than global averages, and some much worse.

The chart below shows projected future cost and carbon intensities of existing Canadian oilsands facilities, and how they compare with some global benchmarks and averages for these metrics. Costs are represented as the West Texas Intermediate (WTI) crude price at which existing facilities would break even in terms of future costs (i.e., it excludes sunk capital costs) and revenues from 2023 forward.[7] Oilsands emissions intensities are calculated on a well-to-refinery basis using Stanford University's Oil Production Greenhouse gas Emissions Estimator,

[6] Department of Finance Canada, "Taxonomy Roadmap Report." https://www.canada.ca/en/department-finance/programs/financial-sector-policy/sustainable-finance/sustainable-finance-action-council/taxonomy-roadmap-report.html#glossary

[7] Breakeven price for currently producing assets is the price at which the net present value of their forward-looking cash flow, discounted at 10%, equals zero.

and international crudes emissions intensities are taken from peer reviewed studies. Oil and gas sector emissions reporting requirements vary in different countries, leading to data quality differences. Uncertainty bars on international references take this into account.

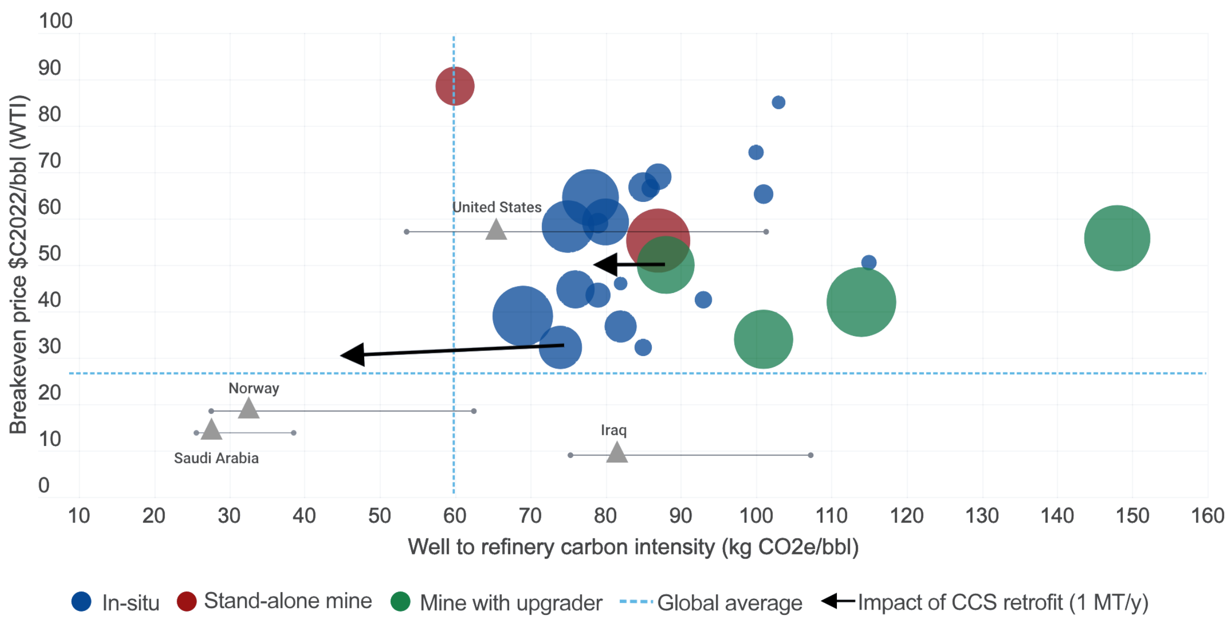

Figure 1. Breakeven price and carbon intensity of selected Canadian oilsands and international crudes, with potential CCS retrofit benefits

Data sources: Masnadi et al, Rystad,, Jing et al, OPGEE[8]

As global action on climate change progresses and oil demand declines, cost and carbon pressures will likely increase risk of stranded assets for facilities higher up and to the right in Figure 1. But CCS may help relieve both those pressures. Each black arrow in Figure 1 indicates the approximate effect of adding 1 Mt of CCS capture capacity to an existing integrated mine (green dot) or in situ facility (blue dot). CCS would reduce the in situ facility's carbon intensity by about 42%, besting the global average emissions intensity, and could generate net before-tax earnings of a little over $2 per barrel. To achieve global average emissions intensity, the mine would need about 5 Mt of CCS capacity installed on its hydrogen plant and natural gas-

[8] Mohammad S. Masnadi et al., "Well-to-refinery emissions and net-energy analysis of China's crude-oil supply," *Nature Energy* 3 (2018). DOI: 10.1038/s41560-018-0090-7

Rystad Energy, UCube Global Asset-Level Oil and Gas Database.

Liang Jing et al., "Carbon intensity of global crude oil refining and mitigation potential," *Nature Climate Change* 10 (2020). https://www.nature.com/articles/s41558-020-0775-3

Brant et al, "Oil Production Greenhouse gas Emissions Estimator (OPGEE)," v. 2.0, 2022. https://eao.stanford.edu/research-project/opgee-oil-production-greenhouse-gas-emissions-estimator fired utility flues; it could also generate over $2 per barrel of net before-tax earnings from CCS under existing and proposed incentives.

> Both projects could generate net earnings from installing CCS equivalent to about $2 per barrel, improving their cost competitiveness.

These improvements would not, however, eliminate the transition risk faced by oilsands facilities. Achieving the Paris Agreement goal requires a steep drop in the average emissions intensity of upstream oil production. Aiming for the current average will not suffice. Moreover, it might not be worthwhile to install CCS at facilities with limited remaining reserves, or very high carbon and cost intensities, because it may not be feasible or justifiable to make them competitive in the medium to longer term. Even for competitive projects, stranded asset risk is not static — those with longer economic lifespans and lower risk today will eventually face high longer-term risk of becoming stranded as global oil demand declines.

No single economic indicator can give a full picture of operations' performance and resilience in any given oil price environment, and factors like planned and unplanned shutdowns, acquisitions, divestitures, and write-downs make it challenging to predict actual performance. Rystad's breakeven price is just one measure of cost intensity, and oil companies also report their own cash operating costs per barrel of production. Reported cash operating costs were generally between C$20 to C$35 per barrel of production in 2022, but products vary in terms of quality and transportation costs, meaning companies also report product volumes and netbacks received.[9] To simplify, if you add $10 or $20 to these costs to represent the range of incremental costs needed to put these on a comparable WTI basis, costs might range from C$30 to C$55 per barrel. This overlaps with but is generally lower than many breakeven price estimates. There are a number of reasons for this, but one is the 10% discount rate Rystad factors into their breakeven prices.

To get an alternative perspective on cost competitiveness at different oil prices, we looked at five companies' Q4 financial reports to see reported annual earnings from their oilsands businesses. We examined how those trend with spot prices for WTI and Western Canadian Select (WCS) (converted to 2022 real Canadian dollars) in 2017–2022.[10] One operator had

[9] Netbacks are the revenues from selling a unit of oil or gas, minus all costs associated with getting that unit to the marketplace (production costs, transportation, royalties). See Investopedia, "Netback: Definition, Calculation Formula, Analysis, Example." https://www.investopedia.com/terms/n/netback.asp

[10] Suncor, "Quarterly Reports," https://www.suncor.com/en-ca/investors/financial-reports/quarterly-reports; Imperial Oil, "Annual and quarterly reports and filings," https://www.imperialoil.ca/en-CA/Investors/Investor-relations/Annual-and-quarterly-reports-and-filings; Canadian Natural Resources Limited, "Quarterly Reports," https://www.cnrl.com/investors/financials/; Cenovus, "Financial results,"

positive earnings from their oilsands business across the full range of prices in that period. All companies generated significant, often record-breaking, earnings in 2021 and 2022 when WTI averaged $84 to $123 per barrel (WCS was above $67 per barrel). But four of the five companies' oilsands businesses had very mixed performance in 2017–2020 (reported annual losses 50–75% of the time) when prices averaged below $80 per barrel WTI ($50–$78 per barrel WTI and $34–$55 per barrel WCS). Since that time, the companies continue to improve their costs; some costs in 2017–2020 were one-time write-downs (such as to reflect the lower value of some of their assets). But this historic check indicates that below $80 per barrel WTI, earnings were a challenge for the oilsands business.

#2: Governments should follow through with announced policy measures so that installing CCS on existing oilsands facilities is economically viable before 2030

A key indicator for whether any decarbonization project is economically viable is how its cost compares to Canada's rising headline carbon price. If the cost to reduce (or eliminate) emissions from a facility is cheaper than paying a carbon price on these same emissions, businesses have an incentive to build the decarbonization project.

Our modeling shows that both types of CCS projects are economically viable against this measure. We estimate that installing CCS at an in situ facility (capturing and sequestering emissions from natural gas-fired steam and power) and an integrated oilsands mining facility (capturing and sequestering emissions from the upgrader hydrogen plant), will cost between $89 to $144 for each tonne of emissions avoided. This cost is below the headline carbon price of $170 per tonne in 2030.

Our results also emphasize the importance of policy certainty from governments, especially the commitment to implement carbon contracts for differences (CfDs). In response to calls from investors, industry, and environmental groups to improve carbon pricing certainty, the federal government is moving ahead with designing a framework for CfDs. CfDs could act as insurance for carbon pricing revenues that decarbonization projects depend on for their business cases. CfDs may take different forms, but the general idea is for low-carbon project proponents to request (or bid through a reverse auction) the lowest carbon price or carbon credit price they could accept in order for their project to go forward. Federal or provincial governments would award a CfD to competitive proposals, essentially guaranteeing that carbon price to successful projects. Importantly, the Canada Growth Fund is mandated to provide concessional financing,

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https://www.cenovus.com/Investors/Financial-results; MEG Energy, "Financial Information," https://www.megenergy.com/investors/financial-information/; Government of Alberta, "WCS oil price," https://economicdashboard.alberta.ca/dashboard/wcs-oil-price/

which means it can offer below-market financing costs but with an expectation to recoup its investments. If the carbon price and credit values remain above the agreed CfD price, the contracts do not cost the government money (and may actually earn government a return). If the prices drop below what was agreed, then government pays the project the difference.

These contracts can allow project developers to bank on the fact that Alberta's Technology Innovation and Emissions Reduction (TIER) system credit prices — the big driver of net revenues for CCS projects — will track with the federal carbon price over the lifetime of each project. Our analysis also underscores the importance of the proposed CCUS investment tax credit and credit prices under the federal government's Clean Fuel Regulation credits for certain CCS project business cases.

Table 1 shows a range of breakeven project costs in a medium-cost scenario for a 1-Mt capture per year CCS project installed at an average sized in situ facility, abating 63% of that facility's pre-CCS emissions. Depending on operating life, this CCS project would break even with a sustained project carbon cost between $111 and $144 (real 2023 $) per tonne. These breakeven prices emphasize the importance of carbon price certainty — possibly provided through CfDs, as the business case for projects that operate through the 2030s and 2040s depends on a carbon price that is at least maintained past 2030.

Table 1. Costs and revenues for a CCS project on an in situ oilsands facility (medium-cost scenario)

Operating life (years)	Project cost ($/t CO_2)	Net Earnings* ($/barrel of production)
30	$111	$2.31
25	$114	$2.23
20	$119	$2.12
15	$128	$1.91
10	$144	$1.51

* with a $170/t carbon price, CCS investment tax credit, and Clean Fuel Regulation credits

For reference, $144 per tonne (in 2023 dollars) is below the headline carbon price of $170 per tonne in 2030, when accounting for 2% annual inflation. Even if the project only operates for 10 years (to reflect stranded asset risk), it can still break even in this scenario. This CCS project could generate real dollar net earnings of $1.51 to $2.31 per barrel, under mid-range assumptions for carbon pricing credits, CCS investment tax credit, Clean Fuel Regulations and certainty provided by CfD, minus operating and capital costs.

Table 2 shows a similar range of breakeven project costs in a medium-cost scenario for a 1-Mt capture per year CCS project installed at an average-sized integrated mine hydrogen plant, abating 12% of that facility's pre-CCS emissions. Depending on operating life, this CCS project would break even with a sustained project carbon cost between $89 and $117 (real 2023 $) per tonne. Again, even projects with a short lifespan of 10 years can break even. This CCS project could generate real dollar net earnings of $0.50 to $0.61 per barrel, under mid-range assumptions for carbon pricing credits, CCS investment tax credit, Clean Fuel Regulations and certainty provided by CfD, minus operating and capital costs.

Table 2. Costs and revenues for a CCS project on an integrated mine hydrogen plant (medium-cost scenario)

Operating life (years)	Project cost ($/t CO_2)	Net Earnings* ($/barrel of production)
30	$89	$0.61
25	$92	$0.60
20	$96	$0.59
15	$103	$0.56
10	$117	$0.50

* with a $170/t carbon price, CCS investment tax credit, and Clean Fuel Regulation credits

We also ran a range of sensitives in the model. Of these, a project's operating lifespan, cost of capital, capital expenditures for installing the CCS technology, and transport tariffs had the largest impacts on results. If CfDs were not assumed to be in place, carbon pricing sensitivities would also be significant. A wide range of project lifespans (10 to 30 years) and costs of capital (5–15%) were considered to reflect key project details that may be impacted by transition risk considerations relevant to oilsands CCS investments.

#3: New subsidies are not required to get oilsands CCS off the ground

The results from our cash flow model show that government policies are critical to making oilsands CCS economically viable. Government funding in the form of a limited CCUS investment tax credit can help reduce the risk for these big, capital-intensive projects and kickstart decarbonization in the oilsands — as well as in other sectors such as cement.

But our analysis also provides important insights into the broader debate about fossil fuel subsidies on the path to net-zero.

Most of the big incentives for oilsands CCS come from carbon pricing, especially TIER credits but also Clean Fuel Regulations credits. Importantly, these incentives do not come from taxpayers. The federal government has also committed to providing tax credits for CCS projects, which are a more conventional type of public subsidy. There are other sources of potential support on offer, such as using the federal government's new Canada Growth Fund or direct funding through changes to the Alberta Government's Petrochemicals Incentive Program. But many in industry have asked for additional public funds for CCS and especially the CO_2 pipeline, above and beyond the existing and proposed measures. The Pathways Alliance, representing the largest oilsands operators, is specifically requesting governments to shoulder more of the total cost of CCS projects.

At a minimum, our results suggest that by 2030, additional public supports for oilsands CCS will likely not be required to make these projects economically viable. In fact, with Canada's existing and proposed incentives, our analysis shows that Alberta's oilsands CCS projects could generate healthy or even high private returns.

The table below indicates that when all incentives and public supports are accounted for, oilsands CCUS projects could have a before-tax average internal rate of return of 12% (8–16%) for in situ and 21% (11–33%) for mining.

Table 3. Internal rates of return for modeled in situ and mining CCS projects

	Internal rate of return			Average internal rate of return
	Low cost scenario	Mid cost scenario	High cost scenario	
In situ oilsands facility (CCS on gas-fired flue)	16%	11%	8%	12%
Integrated oilsands mine (CCS on hydrogen plant flue)	33%	18%	11%	21%

For what is arguably a cost of doing business in the global low-carbon transition, these estimates suggest healthy returns. If emissions reductions at upstream oilsands are treated more as a cost of compliance (instead of an optional investment), these results suggest that further supports risk overpayment of public funds to oilsands CCS and may run counter to Canada's commitment to phase out inefficient fossil fuel subsidies. To put these returns in context with other publicly funded projects, the Alberta Utilities Commission mandates an 8.5% return on equity from regulated electricity projects.[11]

Our results also highlight the importance of designing existing and proposed policies to minimize the risk of carbon lock-in and stranded assets and reduce the opportunity cost of public spending on large decarbonization projects like CCS by ensuring they do not generate excessive profits from public funds. For example, this could mean designing carbon contracts for differences so there is some competitive pressure and transparency as companies request the lowest contracted carbon price they can live with. It could also mean focusing government policies on oilsands projects that can demonstrate lower production costs and lower carbon emissions, betting on projects that will have a greater chance of surviving declining global demand.

Conclusion

Our cash flow results suggest that investments in CCS by the oilsands sector are cost-effective and generate a positive (private) return of up to $2 per barrel. They could also help the sector become more competitive as demand for oil declines in the global low-carbon transition, potentially reducing their emissions intensity by 40%. In fact, in the context of the federal government's forthcoming cap on oil and gas emissions, investments in CCS will become a cost of doing business and a form of regulatory compliance.

These positive returns are based on carbon price certainty for the life of the project, which can be achieved by tools like contracts for difference — which are not yet available. Policies like CfDs and the announced investment tax credit are critical for providing certainty for the sector to make what will amount to billion-dollar investments in CCS technology.

Our results also suggest that public supports for CCS adoption could be too high in certain cases, potentially resulting in high private returns for what arguably should be a cost of compliance with Canada's proposed oil and gas emissions cap. Our research suggests that despite calls for further subsidies by industry, announced incentives and public support is likely sufficient in many cases. However, governments need a clearer framework for evaluating the costs and benefits of public support for individual projects to ensure efficient use of public funds for transition investments. For example, CfDs could be awarded through a competitive process to projects that request the lowest guaranteed carbon price.

[11] Alberta Utilities Commission, "Determining a fair rate of return on regulated utilities." https://www.auc.ab.ca/rate-of-return/

There are other issues with public support for oilsands CCS, such as the risk of locking in high-emitting industry and fossil fuel production for longer. Also, facilities with higher production costs, higher carbon intensities, and longer lifespans will face a higher risk of becoming stranded in the coming decades as global demand declines; they therefore represent a riskier investment for taxpayers. We explore what this type of framework could look like in a separate piece, as part of this series in Policy Options.[12]

The global low-carbon transition means a new operating environment for Canada's oil sector — and oilsands in particular. As we continue to see global capital and policies both shift in favor of green investments aligned with net-zero emissions goals by many governments and companies, transformative investments that drastically reduce emissions, such as CCS, will become paramount to staying competitive and a cost of doing business.

[12] Rachel Samson, Jonathan Arnold, "Ottawa must think carefully about subsidies for oil and gas emission reductions," *Policy Options*, July 10, 2023. https://policyoptions.irpp.org/magazines/july-2023/subsidies-oil-gas/

Appendix: Methodology and references

The high end of CCS costs were estimated using data from Shell's Quest project[13] and a Jacobs Consultancy study for Alberta Innovates (AI) on CCS[14] on once-through steam generators. Low cost estimates came from the U.S.-based Great Plains Institute (GPI).[15] Pipelines costs were derived from published COSIA analysis.[16] Medium costs were mean averages between high and low costs for a given CCS technology.

As per normal practice in project cash flow analysis, avoided costs, such as avoided TIER compliance costs, are treated as incentives to do the project, and improve returns the same as revenue.

Government incentives for CCUS included the value of avoided compliance costs and emissions credits in Alberta's Technology Innovation and Emission Reduction (TIER) system, subsidies from the federal CCUS Investment Tax Credit, federal Clean Fuel Regulations credits, and carbon pricing certainty that could be gained from federal contracts for difference. We ran sensitivities for each archetype to account for:

- Operating life (10–30 years)
- Weighted average cost of capital (5–15%)
- Capture costs (low-middle-high)
- Transport tariff costs (low-middle-high)
- Estimated future value of TIER compliance fund payments and credit prices (85–95% of headline carbon price). TIER headline carbon price assumed to escalate with inflation (2%) after 2030 (e.g. $174 in 2031)
- Estimated future value of Clean Fuel Regulations credits for oilsands facilities
- CCUS Investment Tax Credit (announced rates)

Electricity use: Electricity assumed to be self-generated onsite from existing generation, so its use means foregone electricity sales revenue. Cost is valued at NGX Forwards pricing.

Variable costs: Cases based on GPI and AI data use gas and power consumption rates to calculate variable costs. Cases based on Quest use Quest's published variable costs.

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[13] Alberta Department of Energy, *Quest Carbon Capture and Storage project: annual report, 2021.* https://open.alberta.ca/publications/quest-carbon-capture-and-storage-project-annual-report-2021

[14] Jacobs Consultancy, *Impact of CCS Technology Study: Stage One Report,* prepared for Alberta Innovates (2011). https://albertainnovates.ca/projects/impact-of-ccs-technology-study-stage-one/

[15] Elizabeth Abramson, Dane McFarlane, Jeff Brown, *Transport Infrastructure for Carbon Capture and Storage* (Great Plains Institute, 2020). https://betterenergy.org/wp-content/uploads/2020/08/GPI_RegionalCO2Whitepaper.pdf /

[16] Canada's Oil Sands Innovation Alliance, *Oil Sands CO_2 Pipeline Network Study* (2017). https://cosia.ca/sites/default/files/attachments/Final%20Report%20COSIA%2018%20July.pdf

Hydrogen plant capital and operating expenditures: High cost scenario is based on Quest capture with COSIA high transport tariff and GPI storage tariff. Low cost scenario is based on GPI refinery hydrogen plant and storage tariff with COSIA low transport tariff; medium is based on a simple mean of these costs.

Gas-fired boiler capital and operating expenditures: High cost scenario is based on AI OTSG capture with COSIA high transport tariff and GPI storage tariff. Low cost scenario is based on GPI NGCC and storage tariff with COSIA low transport tariff; medium is based on a simple mean of these costs.

Figure 1: For field level analysis, we matched field names, production volumes, and operator names for year 2021 between the Rystad Ucube database and publicly available data from regulators. Additional operational data such as number of wells, water or steam injection for each field were used from publicly available sources. Once field was matched with Rystad data, breakeven price was used from Rystad for each matched field.

Scope of projects selected: The Rystad Ucube dataset includes both project or field names as well as child or asset level sub-field name. Given that operational and production information is publicly available at the project/field level, field matching was done at the project level. The difference between Rystad and regulator sources for liquids production volumes for year 2021 was within 1%.

Approximately 97% of the producing fields in Canada in 2021 had a liquids production level higher than 5,000 barrels per day.[17] Therefore, fields with production rates less than 5,000 barrels per day were not included. These fields not only have lower share of the overall production, but lack accessible operational data and are harder to match between publicly available datasets. This leads to higher uncertainty in their emissions intensity assessment relative to the larger oilsands fields. While the volume of production from each individual asset is small, collectively these fields present a major data gap. This gap has been recognized in many of oil emission intensity academic studies.

Thirty-six fields representing 3.3 million barrels per day (~62% of Canada's total liquids production) have more reliable operational data, and include oilsands, primary and offshore fields. We used the Oil Production Greenhouse Gas Emissions Estimator (OPGEE V2.0) to model the well-to-refinery emissions for each project individually. Alberta fields operational data was sourced for year 2021 from the Alberta Energy Regulator reports ST39, ST53.[18]

[17] Based on Rystad database asset classification. For example, Montney Play is grouped under one project but includes ~185 assets or sub-projects, each having a unique production profile, operator and economic analysis.

[18] Alberta Energy Regulator, *ST39: Alberta Mineable Oil Sands Plant Statistics Monthly Supplement.* https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st39; *ST53: Alberta In Situ Oil Sands Production Summary.* https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st53

Table 4. Summary of assumptions for both project types, transport, and storage

Cost Scenario	Capture capex (real 2022 C$ million)	Capture fixed OPEX (real 2022 C$/t CO_2)	Electricity usage (MWh/t CO_2)	Estimated electricity variable OPEX (real 2022 C$/t CO_2)	Natural gas usage (HHV GJ/t CO_2)	Estimated natural gas OPEX (real 2022 C$ million/t CO_2)	Total fixed and variable OPEX (real 2022 C$/ t CO_2)
Gas-fired power plant: in situ facility							
High cost capture Alberta Innovates	696.14	27.79	0.21	10.91	5.05	14.82	53.52
Low cost capture Great Plains Institute	554.76	19.10	0.10	5.16	2.46	7.21	31.47
Mid cost capture average of high and low cost	625.45	23.45	0.16	8.03	3.75	11.02	42.50
Hydrogen plant: integrated oilsands mine							
High cost capture Quest project	853.63	15.79	20.40	--	--	--	38.82
Low cost capture Great Plains Institute	243.98	8.40	0.18	9.29	2.69	7.90	25.58
Mid cost capture average of high and low cost	548.80	12.10	18.79	--	--	--	30.89
Pipeline tariff COSIA							
High Cost	--	--	--	--	--	--	29.81
Low Cost	--	--	--	--	--	--	15.46
Mid Cost	--	--	--	--	--	--	22.63
CO_2 storage cost Great Plains Institute	--	--	--	--	--	--	6.77