

In Search of Prosperity:

The role of oil in the future of Alberta and Canada

IISD REPORT



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In Search of Prosperity: The role of oil in the future of Alberta and Canada

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Highlights

This report takes a novel approach to considering the role of oil in Alberta's future prosperity. It casts the net much wider than most industry analyses in thinking about drivers of future demand and viability. And unlike most environmental analyses, it ignores the question of whether a thriving oil sector is consistent with climate imperatives, focusing instead on to what extent a thriving oil sector is possible, given market realities.

Alberta's oil sector has been an economic workhorse for decades, but its long-term market outlook is bleak. By the end of this decade, a combination of technological change, climate action, market forces, and geopolitics will drive a long-term decline in the sector, meaning its contribution to Alberta's future prosperity will be nothing like what it was in the past.

As a way to create jobs, foster investment, and drive government revenues, investing public funds in the oil sector is not money well spent. Alberta's future prosperity would be better served by governments investing in diversifying the economy, building on the strengths that powered the oil sector success: a skilled workforce, an entrepreneurial spirit, and abundant resources.

Oil-dependent workers and communities need help to navigate the coming transition. Any major economic transition is painful, but we know from experience that it can be made much less so if it is anticipated and managed.

Oil has an important place in that transition. Existing operations will still generate revenues that can be harnessed to support new investments. Just as important: oil sector expertise, infrastructure, and resources may be the basis of new drivers of prosperity.



Executive Summary

The oil sector has been an economic workhorse for Alberta for decades. Oil sands extraction and refineries alone contributed over CAD 68 billion to the Alberta economy in 2019 and made up over 18% of Alberta's provincial GDP. When it comes to employment, four subsectors of oil and gas activity—extraction, support services, refining, and pipeline transport—provided 131,405 direct jobs in Alberta in 2019, or 5.4% of the provincial workforce.

Alberta's oil sector, however, has run into headwinds. Even before the COVID-19 pandemic and the oil price crisis it sparked, Alberta had been struggling to recover from the 2014/15 oil price shock brought on, in part, by the flood of new U.S. shale production. By 2019, real GDP still had not climbed back to 2014 levels, growing an anemic 0.04% over 2018 levels.

This report examines the future of the oil sector as part of Alberta's economy and whether, in years to come, it will drive economic prosperity in the same way it has in the past.

The report approaches this question through two tracks: (i) assessing determinants of the sector's future and (ii) modelling scenarios.

The first track considers the impact on the sector of the following determinants:

- **Uptake of electric vehicles (EVs):** The uptake of EVs is the most significant influence on future oil demand. Road transport is by far the biggest component of global demand for crude oil, at 44%. The increased uptake of EVs will therefore have a direct and significant impact on the oil sector. EV uptake is growing rapidly. Meanwhile, a growing number of countries and states have announced bans on the sale of internal combustion engine passenger vehicles, coming into effect as soon as 2030, in order to favour non-polluting vehicles like EVs.
- **Government action on climate change worldwide:** The combustion of oil is responsible for 21% of total anthropogenic greenhouse gas (GHG) emissions globally. Modelling by the Intergovernmental Panel on Climate Change shows that all but the most implausible scenarios for meeting the Paris Agreement's 1.5°C warming target mean significant reductions in oil use. Increasing international action to meet climate commitments, under the Paris Agreement and more ambitiously toward 2050, will reduce demand for oil.
- **Cost of production:** Oil sands operations are capital intensive. Greenfield mining operations in particular face much higher costs than averages for global competitors, along with high upfront investment and significant payback times. These kinds of projects are unlikely to move forward in the future. On the other hand, expansions of existing in situ operations have proven to have low and globally competitive breakeven costs. Existing operations are a different story, with operating costs having fallen significantly. Such operations, especially if they have paid off their initial investments, can survive low global prices for extended periods of time.



- **The geopolitics of oil markets:** Canada is the world's fourth-largest producer of oil but actually accounts for only roughly 5% of total global production. As a result, we are price takers and subject to dynamics among the world's biggest producers. How will these producers behave as global demand eventually peaks? There are two dynamics worth noting. The first is the historical contest among the world's top three producers, with Saudi Arabia and Russia torn between restricting supply to increase revenues or increasing supply to lower prices and destroy high-cost U.S. shale production. The second is based on the so-called green paradox: if oil producers know that a low-carbon world will undermine the future value of their reserves, will they try to get more oil to market today in an undisciplined rush that ultimately harms all producers? In a world of long-run declining oil prices, this second dynamic would put unprecedented strains on OPEC+¹ solidarity, leading to low prices and volatility. When peak demand is eventually passed, the path is not likely to be an orderly decline in prices in a stable but shrinking market.
- **Demand for plastics:** Petrochemical feedstock accounts for 14% of primary oil demand globally, most of which goes into plastics production. Demand for primary chemicals features prominently in all projections for global oil demand. The International Energy Agency's Stated Policies Scenario projects petrochemicals' share of new oil demand growth to be 50% by 2050. However, some uncertainties plague the future of demand for oil for plastic, including alternative production methods that use natural gas and coal-derived methanol, and growing government and private sector initiatives to reduce plastic pollution.
- **GHG intensity of production:** GHG intensity is an important factor because it could be rewarded or penalized by trading partners in the future; it could factor into environmental, social, and governance assessments by the finance sector; and it affects social licence to operate. Canadian upstream emission intensity has improved over the past decade but still remains on average over 50% more GHG intense than the U.S. average and more than three times as high as Saudi Arabia's.
- **Access to capital:** The oil sector is highly capital intensive, and investment in Canada's oil sands has been steeply declining since 2014. Two developments will intensify this challenge. The first is the movement by some major sovereign wealth funds, pension funds, central banks, and investment houses to divest from the oil sands or to filter their investments through a climate lens. Second, the 2019 Supreme Court of Canada case wherein Redwater was required to prioritize the fulfillment of its environmental obligations over repayment of debts raises the risk for creditors and will raise the cost of capital for Canadian oil and gas operators.
- **U.S. energy and climate policy:** The United States is the destination for 98% of Canada's exported crude oil. Stricter regulations and demand-side measures, like

¹ OPEC includes Algeria, Angola, Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Republic of the Congo, Saudi Arabia, United Arab Emirates, and Venezuela. OPEC+ also includes Azerbaijan, Bahrain, Brunei, Kazakhstan, Malaysia, Mexico, Oman, Russia, South Sudan, and Sudan.



President Biden's proposed automobile fuel-efficiency standards, will lower demand for Canadian oil. A moratorium on drilling on U.S. federal lands, on the other hand, could increase demand for Canadian crude imports. Strengthened methane regulations could similarly increase demand for Canadian crude imports by rendering marginal well production in the U.S. uneconomic.

The second track of the report models the expected impacts for two distinct cases: low oil prices and volatile oil prices.

Modelling Low Prices

This first modelling exercise asked: what if the drivers surveyed in the previous section mean that oil prices do not return to meet the pre-pandemic expectations? Our reference case was a pre-2020 prediction by the Canada Energy Regulator: steady USD 70/bbl (West Texas Intermediate [WTI]) oil out to 2050. Our low-oil-price scenario was an average price of USD 55/bbl (Brent) over the same period. For the low-oil-price scenario:

- **GDP from the oil and gas sector:** Average decrease of CAD 4.4 billion per year out to 2050
- **Employment in oil and gas:** Average loss of 6,300 full-time equivalent (FTE) jobs per year out to 2050
- **Investment in oil and gas:** Drops by just over CAD 2 billion per year
- **Royalties from oil sands:** Drop by an average of just under CAD 2 billion per year
- **Alberta-wide investment:** Drops by an average of CAD 2.9 billion per year
- **Provincial tax revenues:** Average decrease of just under CAD 1 billion per year
- **Federal tax revenues:** Average decrease of CAD 1.4 billion per year

Modelling Volatility

To assess the impacts of price volatility on economic outcomes, we created two deterministic price shock scenarios that varied the future oil price based on historic oil shocks from the last 37 years. Both the reference case and the “shock” scenarios had the same average price out to 2050. The impacts of volatility were much greater than the impacts of low oil prices found in the first modelling exercise.

Shocks Scenario:

- **GDP from the oil and gas sector:** Average decrease of CAD 24.3 billion per year out to 2050
- **Employment in oil and gas:** Average loss of 24,300 FTE jobs per year out to 2050
- **Investment in oil and gas:** Drops by CAD 11.2 billion per year
- **Royalties from oil sands:** Drop by 43%



Bigger Shocks Scenario (based on slightly wider distribution of price variability):

- **GDP from the oil and gas sector:** Average decrease of CAD 21.8 billion per year out to 2050
- **Employment in oil and gas:** Average loss of 21,800 FTE jobs per year out to 2050
- **Investment in oil and gas:** Drops by CAD 9.6 billion per year
- **Royalties from oil sands:** Drop by 41%

When considered together, the modelling above and the survey of determinants on which it builds help to coalesce a vision of the future of Alberta's oil sector.

Oil will still be an important part of Alberta's economy in the run-up to peak demand, and even after. However, the post-peak world of low, declining, and volatile prices will make projects and financing more and more challenging, and will make the oil sector a smaller and smaller contributor to Alberta's and Canada's prosperity.

This leads to four policy recommendations:

1. **Oil for combustion is not an appropriate target of industrial policy support.**

For policy-makers with an industrial policy lens who are thinking about where to allocate government support to maximize future prosperity, the oil sector as a producer of combustible hydrocarbons should be nowhere near the top of the list.

2. **Diversification is imperative.**

It is imperative to invest in new growth opportunities. In many cases, this will involve harnessing the same strengths and resources that powered the oil sector to drive new growth sectors.

3. **The transition needs to be anticipated and managed.**

Experience shows that economic transitions for workers and communities can be managed more or less successfully if they are anticipated.

4. **There is no time to lose.**

Evidence shows that successful economic transitions and diversification take decades. It is important that governments, communities, the private sector, unions, and non-governmental organizations accelerate these initiatives now.



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Abbreviations and Acronyms

APMC	Alberta Petroleum Marketing Commission
ARO	abandonment and reclamation obligations
bbbl	barrel
BCA	border carbon adjustment
BNEF	Bloomberg New Energy Finance
bpd	barrels per day
BSS	Bigger Shocks Scenario
CER	Canada Energy Regulator
CO₂e	carbon dioxide equivalent
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EV	electric vehicle
FTE	full-time equivalent
IEA	International Energy Agency
GDP	gross domestic product
GHG	greenhouse gas
OPEC	Oil Producing and Exporting Countries
OPEC+	OPEC plus key non-OPEC members
R&D	research and development
SAGD	steam-assisted gravity drainage
SCC	Supreme Court of Canada
SS	Shocks Scenario
UNDESA	United Nations Department of Economic and Social Affairs
WTI	West Texas Intermediate
WTR	well-to-refinery
WTW	well-to-wheels



1.0 Introduction

The Alberta economy has seen better days. As of this writing, the province seems poised to emerge from a convergence of related crises to see better days once again. This report aims to help move us toward that future prosperity.

Even before the COVID-19 pandemic and the oil price crisis it sparked, Alberta had been struggling to recover from the 2014/15 oil price shock brought on, in part, by the flood of new U.S. shale production. By 2019, real GDP still had not climbed back to 2014 levels, growing an anemic 0.04% over 2018 levels. Employment in January 2020 was down by 9,300 jobs year-over-year, with unemployment at 7.3%.

Things got much worse in 2020. Responses to the COVID-19 pandemic spawned economic carnage across Canada, but among provinces, Alberta was the most severely affected (Conference Board of Canada, 2020). In addition to the COVID-19 crisis, Alberta suffered from an oil price crash that followed both a drop in demand due to the pandemic and a split in OPEC+² on how to respond to it. In April, for the first time in its history, benchmark West Texas Intermediate (WTI) oil prices turned negative. These two related shocks took the province into unprecedented territory. A mid-year projection foresaw a record 11.3% annual drop in real GDP (Conference Board of Canada, 2020). For the first time in 55 years, Alberta qualified to receive, rather than remit, federal equalization payments. The province's unemployment rate jumped over 50% in 2020, from 7.3% to 11.3%, with only Newfoundland and Nunavut performing worse. Business bankruptcies increased 50% over 2019, and personal bankruptcies increased by 45% (Government of Canada, 2020b). And in October 2020, Moody's investor service downgraded Alberta's long-term debt rating from Aa2 to Aa3, citing concerns about a projected deficit more than twice as large as any recorded in Alberta since the financial crisis of 2008 (Moody's, 2020). The rating action also noted that "Despite a decline in the relative importance of oil on revenue, the provincial fiscal profile remains exposed to volatility in oil prices, which are influenced by global pressures, as well as a lack of sufficient pipeline capacity to transport oil efficiently" (Moody's, 2020).

At a broad level, this report focuses on the road to recovery. It asks how Alberta can navigate from the current crisis to once again enjoy prosperity. It is a question that is critically important to Albertan workers, communities, and businesses. It is also important to all Canadians: Alberta has historically been the largest net contributor to federal finances, with net flows peaking in 2014 at over CAD 27 billion (Eisen et al., 2019). And it is important to provincial and federal policy-makers, whose decisions will influence the speed, direction, and sustainability of recovery.

² OPEC includes Algeria, Angola, Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Republic of the Congo, Saudi Arabia, United Arab Emirates, and Venezuela. OPEC+ also includes Azerbaijan, Bahrain, Brunei, Kazakhstan, Malaysia, Mexico, Oman, Russia, South Sudan, and Sudan.



More specifically, this report focuses on the role of the oil sector in that prosperity, given the outsized role it plays in the Alberta economy. As oil prices recover in 2021, Alberta can expect the oil sector to help lead the recovery, with growing investment and production responding to post-pandemic demand (Canadian Press, 2021; Rystad Energy, 2020c) and as rebound demand grows more quickly than supply (International Energy Agency [IEA], 2021). The focus of this report, though, is longer term: in the decades to come, will Alberta's oil sector be able to drive economic prosperity the way it has in decades past?

There are two possible versions of the future to consider. If 2020 was just another downturn in an inherently cyclical market (albeit the worst we have seen), then from a policy perspective, it may make economic sense to invest public funds in supporting the oil sector as a path to Alberta's prosperity. In support of that storyline, the IEA's Stated Policies Scenario sees slowing of growth in oil demand but no peak until 2040, largely on the strength of global petrochemical demand (IEA, 2020b).

However, if the demand for oil or the prospects for investment in the Alberta oil patch are on track for long-term decline, then the story looks very different. In support of that storyline, some have declared that the world has already seen peak demand (Bond, 2020; BP, 2020). An accelerating number of major economies are making net-zero greenhouse gas (GHG) emission pledges (Energy & Climate Intelligence Unit, 2021) and implementing laws and policies that make the "climate ambition scenarios" from various outlooks and forecasts seem more likely. If 2020 was a watershed for global oil demand, or if such a peak arrives soon, then investing public funds in supporting the oil sector—at least as a provider of combustible hydrocarbons—is an ill-advised policy option for Alberta's prosperity. The more appropriate path would involve an urgent drive to diversify and manage the disruptive impacts of the oil sector's decline on workers and communities.

It is critically important to try to bring the future into focus, to situate it between those two possibilities, and to understand the implications for the viability of the oil sector. Clearly, it matters to the workers and communities in Alberta that depend on the sector. It matters to investors and firms that have a stake in the sector. And it matters to provincial and federal policy-makers as they decide where to focus their priorities and support.

It also matters from an environmental perspective, of course. The approved investments in oil, gas, and coal exploration and production worldwide involve a significant overshoot of the Paris Agreement targets for avoiding dangerous levels of climate change (Grant & Coffin, 2019; Stockholm Environment Institute et al., 2020). That existential challenge drives the global policy response that is, in turn, part of the larger picture of future oil demand. But this report does not start from environmental imperatives. It starts, rather, from a concern for the future economic prosperity of Albertans and Canadians.³

³ Ultimately, that distinction is artificial. The costs of not addressing climate change are immense, and the prosperity of Albertans and Canadians, like that of other global citizens, will be directly affected by how successfully the world reduces emissions and adapts to impacts (Sawyer et al., 2020).



It does so, at least in part, in the hope that such a starting point can be the basis for a more productive conversation about oil and energy policy than we have had to date in Canada. Our discussions on the future of oil quickly descend into partisan polemics, with the environmental community arguing that climate change realities mean we need to leave it in the ground and the oil patch arguing that it is better produced by us than by our unethical global competitors. It is hard to see a bridge between those two positions that could lead to national climate and energy policies—a state of affairs that Teck’s President, Don Lindsay, bemoaned in withdrawing the company’s application for the massive Frontier Oil Sands project in 2020 (Lindsay, 2020).

This report aims to help kickstart that urgently needed new conversation. It starts by describing the significant contributions the oil sector has made and continues to make to the Albertan and Canadian economies. It then turns to a survey of key determinants that will influence the future viability of oil in general and Alberta’s oil more specifically. The results of that survey feed into modelling that explores the impacts on the Alberta economy of various plausible futures for oil price/demand. A synthesis section weaves all those strands together to create a coherent vision of the future for oil in Alberta. Building on that vision, the report concludes by considering what it means for policy and for oil’s place in the path to prosperity for Alberta and Canada.



2.0 Oil in the Albertan and Canadian Economies

The oil sector has been an economic workhorse for the Albertan and Canadian economies for decades. This section digs down into that relationship, looking at its contributions in terms of GDP, exports, and government revenues; at its role as a provider of employment; and at the various forms of government support it receives provincially and federally.

2.1 Oil as an Economic Contributor in Alberta, Canada

Table 1 shows that oil sands extraction and refineries alone contributed over CAD 68 billion to the Alberta economy in 2019 (this was pre-pandemic)—a figure that had more than doubled since 2009. In 2019, these subsectors amounted to over 18% of Alberta's provincial GDP (Statistics Canada, 2021e).⁴ At the national level, while those two subsectors constituted only 3.1% of Canada's GDP, Figure 1 shows that crude and refined oil made up fully 18% of Canada's merchandise exports in 2019, with a value of just over CAD 80 billion (down from a peak of almost 22% in 2014) (Statistics Canada, 2021e).

Table 1. Oil sector GDP contributions to Alberta (CAD 2019)

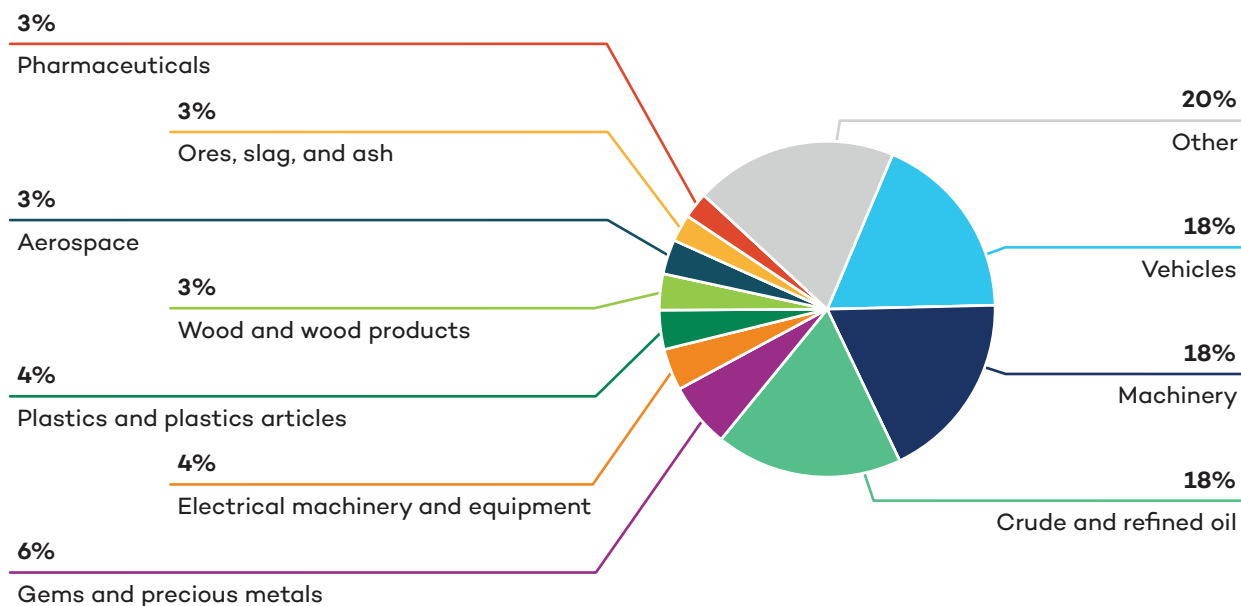
	2009	2019
Oil and gas extraction	55,481	93,204
(of which) Oil sands extraction	27,867	63,381
Support activities for mining, and oil and gas extraction	10,051	11,871
Petroleum refineries	4,219	4,751
Total: Oil sands extraction + refineries	32,087	68,132
All industries	291,404	376,413

Source: Statistics Canada, 2021e.

⁴ Note that these figures do not include support services to the oil sector, which are a major contributor, as shown in Table 1. Data for these are not available disaggregated from gas sector support services.



Figure 1. Canada’s major merchandise exports (2019)

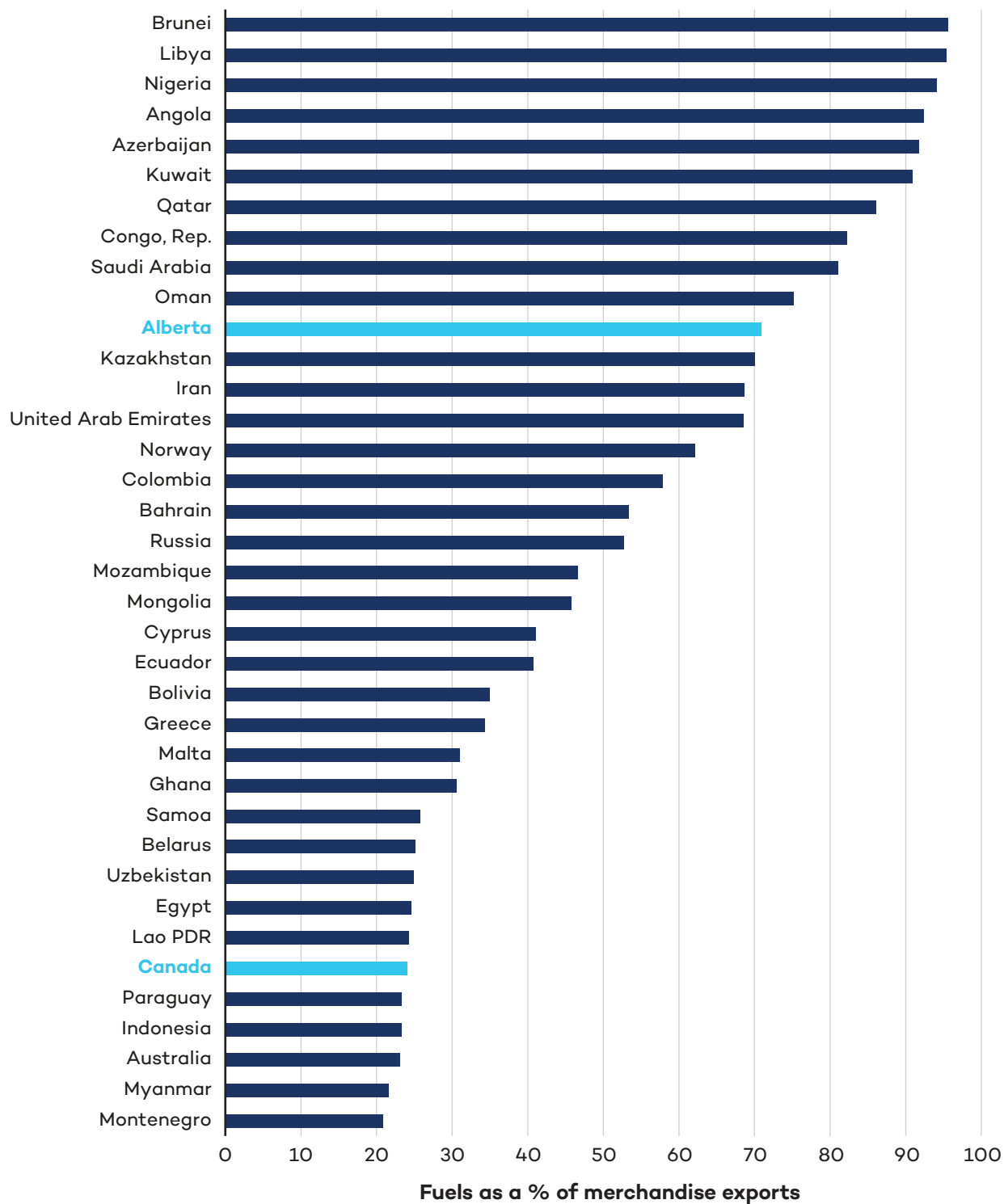


Source: UNDESA, 2021.

The discrepancy between oil dependency in Canada as a whole and Alberta is worth noting: at just over 3% of Canadian GDP, oil sands and refineries are significant but not overwhelming. The corresponding figure for Alberta, by contrast—over 18%—is much more significant. Figure 2 highlights this discrepancy while putting it in a global context. It shows energy exports (this includes not just oil but also all other energy products, including gas, coal, etc.) as a share of merchandise exports for the world’s major exporters. As the figure shows, as a country, Canada is relatively economically diverse, though still dependent on energy exports: its share is 24%. If Alberta were a country, however, it would fall between Oman and Kazakhstan in terms of dependence, at just over 70%.



Figure 2. Export dependence: Canada and Alberta in a global context

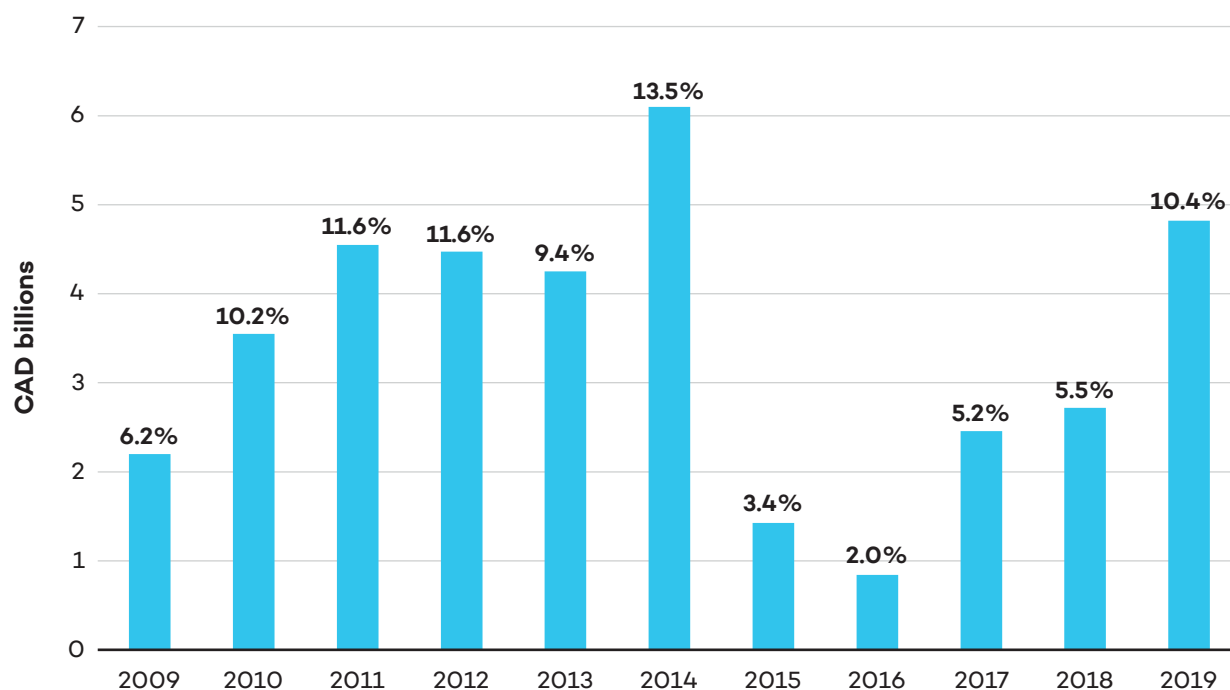


Sources: World Bank, 2021b: Fuel Exports – percent of merchandise exports. “Fuel” includes all Standard International Trade Classification (SITC) Section 3 products. Data shown is for all exporters with shares over 20%. Alberta exports of all products, energy products, are from Statistics Canada, 2021d.



Figure 3 shows royalties paid to the Alberta government by oil sands operations over the last decade. Payments are highly dependent on net cash flows, so they cycle up and down, reaching a high of almost CAD 6 billion in 2014 and a low of CAD 843 million in 2016 (current dollars). Payments over the decade averaged CAD 3.4 billion per year, or 8% of total government revenues.

Figure 3. Alberta oil sands royalties, percentage of government revenues (CAD billions current)

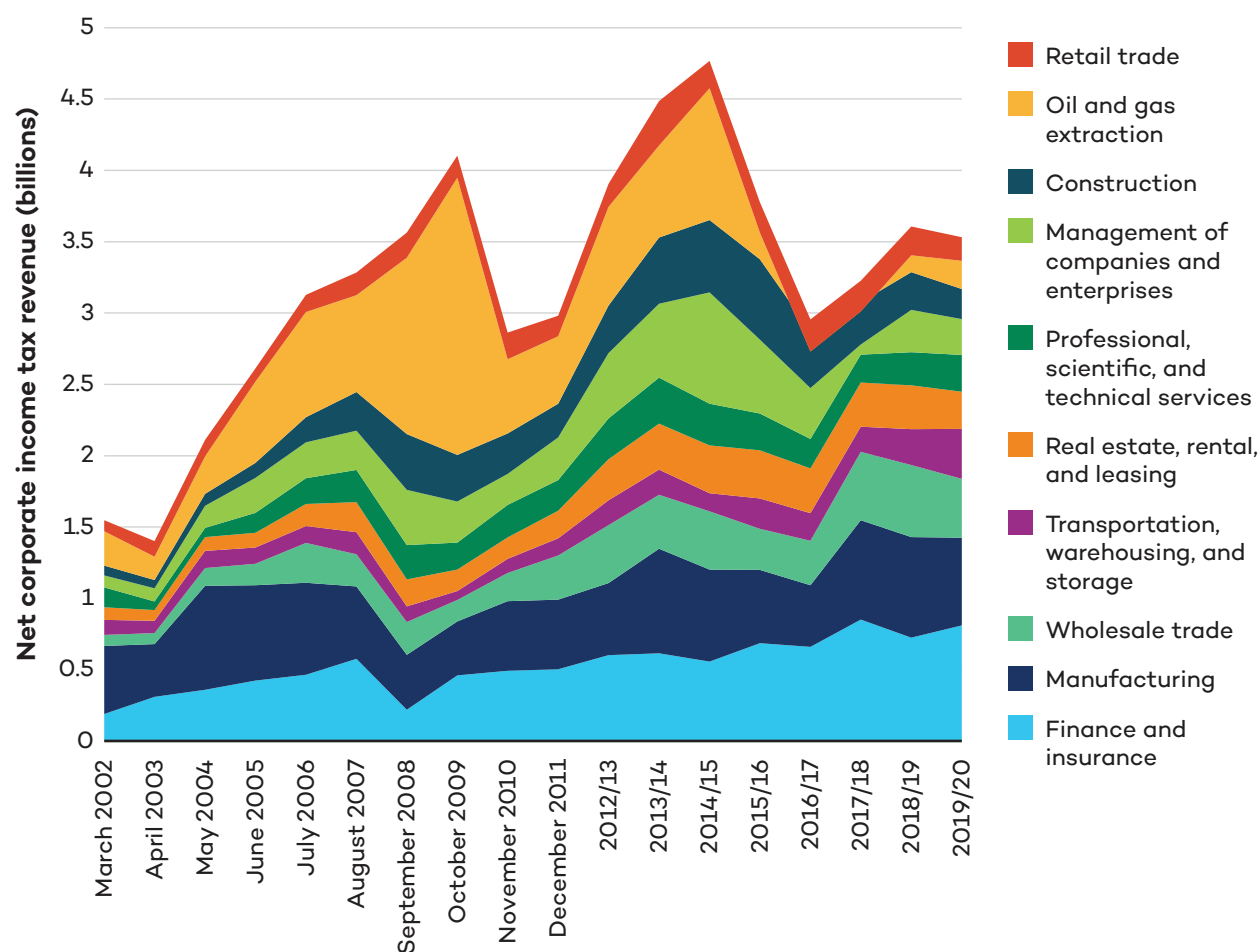


Sources: Royalty figures for 2016–2019: Government of Alberta, 2021; for 2009–2015: Government of Alberta, n.d.b; Revenue figures: Government of Alberta, 2009–2016, 2017b, 2018, 2019.

Royalties are not the only contribution the oil sector makes to public coffers. Also important are corporate income taxes, revenues from permitting, and the income tax revenues derived from oil sector workers. Figure 4 shows Alberta corporate income tax revenues from the top 10 contributing sectors (as of 2019). Oil and gas are shown as a single contributor.



Figure 4. Alberta net corporate income tax by sector (2002–2019)



Source: Government of Alberta, n.d.a. Data are expressed in original North America Industry Classification System (NAICS) classifications. Sectors shown are top 10 contributors as of the 2019/20 tax year. Negative contributions are not displayed.

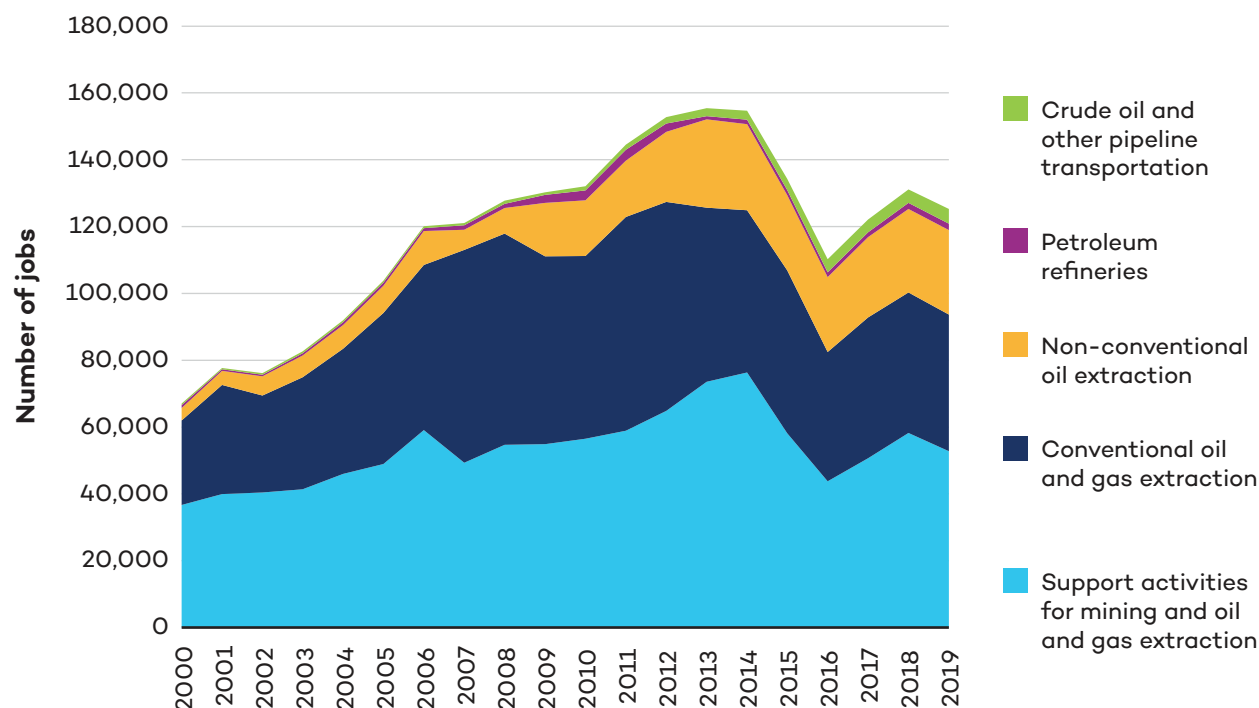
While oil and gas (considered as a single sector) was the top contributor to revenues from 2007 to 2010, it has also been the most volatile, and in 2016 and 2017, it actually turned significantly negative. Since then, it has been low relative to other sectors, ranked ninth of the top 10 in 2019. While important, corporate income tax from the oil sands is not as significant as the royalties shown in Figure 3. While oil and gas corporate income tax revenues surpassed CAD 1 billion only twice in the last 18 years, and in 2019 were under CAD 200 million, royalties for oil sands alone since 2009 have only once dropped below CAD 1 billion.



2.2 The Oil Sector as a Driver of Employment

The oil sector is also a major employer. Figure 5 shows 2019 employment numbers for Alberta for extraction and support services, refining, and pipeline transport. Other than refining, these figures also include natural gas operations, so they will be inflated.⁵ The four subsectors shown provided 131,405 jobs in Alberta in 2019, or 5.4% of the provincial workforce (Statistic Canada, 2021c). These numbers are for workers employed directly and do not include indirect employment (i.e., those employed by contractors and service providers) or induced employment (i.e., jobs created by the spending of the direct employees). Adding these would increase the totals considerably.

Figure 5. Employment in Alberta’s oil and gas sectors (full-time equivalent [FTE])



Source: Statistics Canada, 2021c.

Relative to other sectors, however, the oil sector is not labour intensive. Table 2 shows Alberta’s total multipliers for various sectors. Multipliers tell us what happens if another dollar’s worth of activity takes place in a given sector: how much that would increase GDP, output, labour income, and employment. The employment multiplier used here shows how many jobs are created per CAD 10,000 of spending. For the oil sector, that figure is 0.026, or roughly 1 job for every additional CAD 384,000 (Government of Alberta, 2017a). Oil and gas extraction and refining

⁵ Disaggregated data is not available. If GDP contributions could serve as a rough guide, gas would account for roughly a third of these numbers.



are the worst performers on this list. At the top of the list, the arts, entertainment, and recreation sectors create an additional job with just under CAD 60,000 of additional spending.

However, those numbers have a flip side: the capital-intensive nature of the oil sector means high productivity per worker, meaning in turn that its wages tend to be higher than average wages in other parts of the economy. In the second half of 2020, earnings (including overtime) for employees in oil and gas extraction were almost 90% higher than average wages for employees in all goods-producing sectors in Canada, and they were 134% higher than average wages in the services sectors.⁶

As Figure 5 shows, employment in the oil sector has been on a downward trend since its peak in 2014. In the five years leading up to the pandemic (2014–2019), the four subsectors considered in that table (which include some gas activities as well) lost over 23,000 direct, or almost 18% of its total workforce (Government of Alberta, 2017a). That loss would be larger if we considered the multiplier effects, which of course also work in reverse. The Alberta oil sector has dealt with periodic low prices by relentlessly searching for efficiency and cost savings, including through labour-saving technologies (Stanford, 2021). New applications of technologies like automation, artificial intelligence, natural language processing, and machine learning have driven down employment numbers in the oil sector and will continue to do so. One analysis estimated that those technologies would result in a decrease in direct employment across the oil and gas sectors of 54% (over 46,000 jobs) by 2040 (EY, 2020).

⁶ Author's own calculation based on Statistics Canada (2021b); February 2021 release, average of figures for August, September, October, November, and December 2020. This number does not include self-employed workers.

**Table 2.** Alberta's employment multipliers

	Employment	Relative to average
Arts, entertainment and recreation	0.169	199%
Accommodation and food services	0.163	192%
Retail trade	0.145	171%
Healthcare and social assistance	0.144	170%
Motion picture and sound recording industries	0.109	128%
Other finance, insurance and real estate services and management of companies and enterprises	0.096	113%
Computer systems design and other professional, scientific and technical services	0.087	103%
Legal, accounting and architectural, engineering and related services	0.079	93%
Crop and animal production	0.070	82%
Forestry and logging	0.065	77%
Residential building construction	0.064	75%
Coal mining	0.050	59%
Electrical equipment and component manufacturing	0.045	53%
Pharmaceutical and medicine manufacturing	0.032	38%
Oil and gas extraction	0.026	31%
Petroleum and coal product manufacturing	0.014	16%

Source: Government of Alberta, 2017a. Multipliers are jobs (FTE) created per CAD 10,000 investment in the sector. Average figures are only for the occupations listed here rather than for the economy as a whole.

2.3 Government Support to the Oil Sector

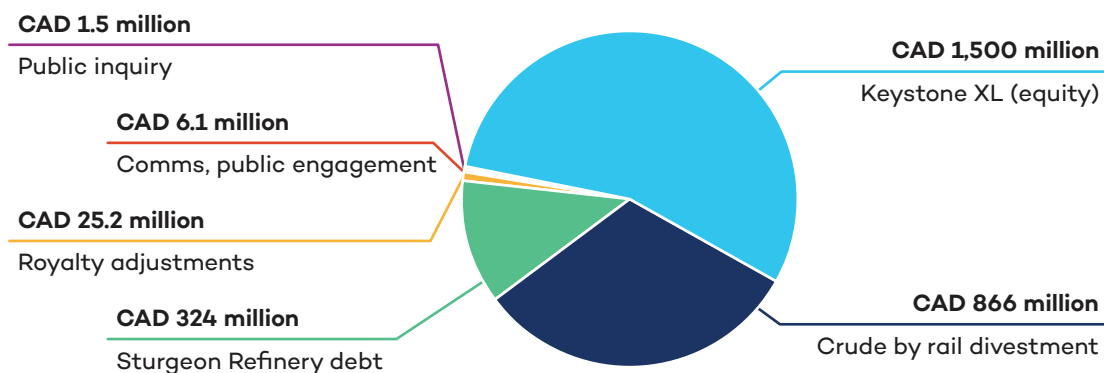
The oil sector in Alberta benefits from substantial government support in the form of grants, tax breaks, royalty adjustments, loans, loan guarantees, equity infusions, export credit, underwriting of losses, advocacy, and other means.⁷ Figure 6 shows the costs of selected major forms of

⁷ Many of these measures have been catalogued and estimated in inventories of subsidies to the fossil fuel sector in Alberta and Canada (Corkal, 2021; International Institute for Sustainable Development & Environmental Defence, 2019). The present report does not pursue the question of whether these support measures are in fact subsidies, asking rather: whatever we label them, are they a good investment?



support in 2019/20, totalling CAD 2.7 billion from the Alberta government alone (Government of Alberta, 2020).⁸ As explained below, this was an exceptional year for volumes of support, but it is indicative of Alberta's policy inclination.

Figure 6. Alberta fiscal support to the oil sector, 2019/20 (CAD millions)



Source: Government of Alberta, 2020.

Alberta's support for the oil sector in 2019/20 included the following:

- **Keystone XL:** Alberta made an equity infusion of CAD 1.5 billion for this export-oriented pipeline. This was an investment, not an expenditure, but the revocation of the project's permit by the US administration means it will become an expense when it is eventually written off. Alberta also provided the proponent with the promise of a loan guarantee of up to 6.4 billion, but this did not become available until January 1, 2021.
- **Crude by rail divestment:** Alberta's previous government entered into contracts for rail cars, loading and unloading terminals, and logistics as part of a push to allow crude exports to travel by rail. Withdrawing from those agreements involved one-time costs in 2019-2020 of CAD 866 million, out of an eventual final cost of 1.5 billion.
- **Sturgeon Refinery:** The Alberta Petroleum Marketing Corporation, per its agreement with the refinery operators, paid CAD 324 million to cover the refinery's debt servicing and some principal. The refinery is not yet processing bitumen.
- **Royalty adjustments:** Two projects (in horizontal oil and enhanced oil recovery) received royalty adjustments (reductions) under a legacy program to encourage innovation.
- **Communications, public engagement:** These funds were directed to marketing campaigns, advocacy and lobbying for Alberta's oil sector. \$1.8 million of this budget was for a "war room" to respond to "misinformation" about the Alberta oil sector, created part way through the fiscal year.

⁸ This is not an exhaustive list, but rather covers a select few key government support measures. For a broad framework for defining government support measures for fossil fuel sectors, see Geddes et al., 2020.



- **Market access activities:** Alberta's Ministry of Energy engaged in various consultation and advocacy efforts in Canada and the United States to promote the oil sector's interests.
- **Public inquiry:** Alberta instigated a public inquiry into foreign sources of funds behind campaigns against Alberta oil.

It is not clear from Alberta Energy's 2020 report (Government of Alberta, 2020) whether there was any support in 2019/20 to the Carbon Trunk Line, a project that captures CO₂ from the Sturgeon Refinery and a fertilizer plant and runs it to central Alberta for enhanced oil recovery and sequestration. That project, which became operational (but not at full capacity) in 2020, and a purely carbon capture and storage project (Quest) have commitments from the province for CAD 1.2 billion in support between 2010 and 2025.

The two major elements of 2019/20 expenditure shown in Figure 6 were one-time outlays totalling more than CAD 2.3 billion, so this was an atypical year. Several current policies could lock in sizable future commitments. The Sturgeon Refinery contracts, for example, involve toll payments by the Alberta Petroleum Marketing Commission (APMC) that, under reasonable assumptions about the crack spread for diesel, would involve tens of millions of dollars of annual losses for the APMC and Canadian Natural Resources Limited (CNRL) (Livingston, 2018). While 2019/20 was an exceptional year for support, the government's willingness to spend that money, even on a one-time basis, is telling: this is a sector that the provincial government believes can deliver long-term prosperity for Alberta.

Federal support for Alberta's oil sector was also atypical in 2020, involving a CAD 1 billion injection of stimulus-type funding for the reclamation of inactive wells (both oil and gas). Alberta's Orphan Wells Association (again, both oil and gas) also received a federal loan of CAD 200 million, with some analysts noting a "significant risk" that it will not be repaid (Bankes et al., 2020). Natural Resources Canada created an Emissions Reduction Fund targeted at onshore oil and gas operations looking to reduce methane and other emissions, worth CAD 675 million. On a more regular basis, Export Development Canada provides over CAD 13.2 billion a year in finance to Canada's fossil fuel sector as a whole, in the form of export credit, risk insurance, and other support, including substantial support to domestic activities (Corkal et al., 2020; Export Development Canada, 2019). It is difficult to quantify the ongoing support provided by the federal purchase and construction of the Trans Mountain Expansion pipeline. That project benefited from a CAD 2.8 billion loan and a CAD 2.3 billion equity infusion, and its construction costs have risen from the projected CAD 7.4 billion to a February 2021 estimate of CAD 12.6 billion (Kapelos & Tasker, 2020). Support in 2020 would have included interest payments, net operational losses, and pension liabilities—which one analysis identified at just under CAD 82 million in the first half of 2019—as well as a host of other indirect expenditures (Sanzillo & Hipple, 2019). Net costs cannot be comprehensively calculated until such time as the pipeline is sold.



3.0 Determinants: The future of the oil sands

This section surveys eight critical determinants that will influence the future of Alberta's oil sands. The first three are characteristics of the sector itself:

- Cost of production
- GHG intensity of oil
- Access to capital.

The five remaining determinants are drivers affecting global markets:

- Government action on climate change
- U.S. energy and climate policy
- Uptake of electric vehicles (EVs)
- Demand for plastics
- The geopolitics of oil markets.

For each, the sections below briefly describe how that determinant is related to the future of Canadian oil, trends and likely developments, and thoughts on the implications.

There are at least two obvious determinants missing from that list: we do not discuss GDP and population growth, to which the demand for oil has traditionally been strongly linked. This is because the facts of GDP and population growth are fairly straightforward. Falling fertility rates notwithstanding, the global population is on track to hit 8.5 billion people in 2030, 9.7 billion by 2050, and 10.9 billion by 2100, nearly all of that in urban centres (United Nations Department of Economic and Social Affairs [UNDESA], 2019). Eight countries will see nearly 50% of the anticipated population increase: India, Indonesia, Nigeria, Pakistan, Tanzania, the Democratic Republic of the Congo, Egypt, Ethiopia, and the United States (UNDESA, 2019). Most long-term predictions for GDP growth (which are notoriously difficult to get right) see a slower pace than what has characterized the past 50 years. Still, PWC's flagship 2017 report on the subject foresees respectable average growth of 2.6% over the next 30 years. They see this growth dominated by emerging markets, including China, India, Indonesia, Brazil, Russia, and Mexico, driven largely by growth in the working-age population (PWC, 2017). The rise in population and GDP in emerging economies, and particularly the rise of the middle class, represents a potential source of demand for oil, both as fuel and as a feedstock for plastics (see Section 3.3).

Also missing from the list is export infrastructure, where the facts and uncertainties are well known. Lack of pipeline capacity damaged the sector in 2018 when increased supply and restricted export access caused prices to fall, leading to the introduction of provincially ordered curtailment. With the cancellation of the permit for the Keystone XL pipeline, we know that access to Gulf Coast refineries is likely to continue to be restricted. Attention has turned to the Trans Mountain Expansion, which would move 590,000 bbl/day from Edmonton to Burnaby



on Canada's West Coast, and the Line 3 replacement, which would move oil from Edmonton to the U.S. Midwest refineries, doubling existing capacity to 760,000 bbl/day. Crude exports by rail have also increased, reaching over 400,000 bbl/day in January 2020 (triple the volume from 5 years previous) before falling in response to the COVID-19 crisis (Statistics Canada & Canada Energy Regulator [CER], 2021). The CER's 2020 "reference scenario" (which assumes no additional climate policies over and above those currently in place) sees these pipelines *and* the now-cancelled Keystone XL as needed to keep up to supply increases out to 2050 (CER, 2020). The CER's "evolving scenario" (which assumes increasing climate action and development of low-carbon technologies) sees lower supply available for export, with volumes that could be taken by existing pipeline capacity plus one of either Line 3 or the Trans Mountain Expansion. As such, whether export infrastructure will hamper the sector's prospects in the future depends on two key unknowns: whether the Line 3 replacement and the Trans Mountain Expansion are built and whether there is continued development of low-carbon technologies and continued climate policy action per the CER's "evolving scenario" (See Section 3.2).

While they do not merit full treatment here, both of these determinants are important to bear in mind through the rest of this section as we survey other drivers with which they will interact.

3.1 Cost of Production

HOW IS THE COST OF PRODUCTION RELATED TO THE FUTURE OF THE OIL SANDS?

Canadian crude oil, though it is almost all exported to a single destination, is sold into a global market. The viability of future oil sands production depends on the ability of its producers to compete in that market at the prevailing prices.

WHAT ARE THE TRENDS IN COSTS OF PRODUCTION?

Costs of production vary by facility, affected by the resource characteristics, the technology used, and according to the stage in the life cycle of the operation. As a general proposition, oil sands are relatively capital-intensive operations, meaning they are high-cost by global standards. Table 3 shows breakeven oil prices for projects not yet producing from a variety of sources. In this analysis, new oil sands production needs the highest prices of any variety globally by a significant margin.

**Table 3.** Cost of the supply curve for new oil resources

	2020 USD/bbl (Brent)		% Reduction
	2015	2020	
Producing fields	32	23	27%
Unsanctioned fields			
Onshore Middle East	48	31	35%
Deepwater	68	43	36%
North American shale	74	44	41%
Offshore shelf	64	48	25%
Extra heavy oil	73	49	33%
Onshore Russia	69	53	23%
Oil sands	86	69	20%

Source: Rystad Energy, 2015, 2020b. Figures are averages of 60% confidence intervals for each resource. Breakeven means a net present value of zero with a 7.5% discount rate.

However, the cost figures in Table 3, while they are indicative, do not tell the whole story. For one thing, they are for unsanctioned resources, so they tell us nothing about existing production. As well, they are aggregate figures that fail to show the significant variation among different prospects.

Existing oil sands production is primarily of two sorts: in situ and mining. The latter involves surface mining (down to a depth of 75 metres) a mixture of bitumen (heavy oil, almost solid at room temperatures), sand, and water. About 20% of Alberta's oil sands are amenable to mining, and mining accounts for about half of total oil sands production—a percentage that is steadily falling. In situ operations involve well extraction of deeper deposits (typically 200 metres or more). Most in situ is now done by steam-assisted gravity drainage (SAGD), which involves forcing high-pressure steam via an injection well into an underground deposit to cause the bitumen to flow to a producing well, from which it is pumped up. Table 4 shows the supply costs to the field gate of a hypothetical oil sands operation, given typical costs and assuming different types of operation.

**Table 4.** Field gate oil sands supply costs, 2012–2019 (2020 USD/bbl)

	2012	2013	2014	2015	2016	2017	2018	2019
SAGD	51.07	54.94	55.12	58.11	-	36.64	36.18	32.16
SAGD expansion	-	-	-	-	-	-	23.20	21.86
Stand-alone mining	69.67	78.88	77.77	69.54	-	59.29	-	-

Source: Canadian Energy Research Institute, 2013, 2014, 2015, 2017, 2018, 2019; Statistics Canada, 2021a. Costs assume 10% real return on investment. USD-CAD exchange rates from OFX, n.d.

Table 4 shows a large gap between the costs of SAGD and stand-alone mining operations (that is, not integrated with upgrading). Oil sands mining is characterized by high upfront costs, large-scale operations, and low operating costs, so the hypothetical greenfield operations described in Table 4 reflect those high costs. However, once mining operations reach payback, they generate significant revenue streams for decades, even at low oil prices.

Tables 3 and 4 also show cost declines over time. An analysis covering the period from 2014 to 2018—when oil prices plunged and the sector was forced to find efficiencies—estimated average capital cost reductions of 10% for new oil sands projects and operating cost reductions of between 40% and 50%, making a 2018 project a quarter to a third cheaper than it had been four years earlier (Birn, 2019).

Table 4 also shows that the lowest costs are associated with expansions of existing SAGD projects. This reality is reflected in the pipeline of projects awaiting final investment decision. Rystad surveyed 10 potential Canadian oil projects awaiting final investment decision, and four of the five lowest breakeven prices were all associated with in situ oil sands expansion (Rystad Energy, 2020c).⁹ The highest breakeven cost among them—estimated at USD 48/bbl (Brent)—was for Syncrude’s Mildred Lake extension, a pair of mines. These expansion projects are significantly cheaper than the average for oil sands shown in Table 3 (which, it should be noted, have different underlying assumptions) and, as such, are likely to receive investment approval (Rystad Energy, 2020c).

CONCLUSIONS

The costs of oil sands operations, surveyed above, are varied. Expansions of existing in situ operations have the lowest breakeven costs and can be executed at globally competitive levels.

⁹ From lowest cost to highest, they were: Christina Lake 5th and 6th OTSGs (MEG Energy), Christina Lake Phase H (Cenovus), Foster Creek Phase H (Cenovus), Christina Lake eMVAPEX (MEG Energy), and Mildred Lake Extension (Syncrude).



Even greenfield in situ operations may be profitable at oil prices of USD 50/bbl, though much less so than expansions; they are at the high end of global breakeven costs.

Greenfield mining operations, however, face much higher costs than averages for global competitors and significant payback times. Teck's Frontier mine, for which the company withdrew its application in 2020, assumed oil prices of more than USD 95/bbl (WTI), though breakeven was likely well below that (Friedman, 2020). That project had an estimated construction cost of CAD 20.6 billion and would have produced 260,000 barrels of oil a day (or 17% of total mining production in 2019) for an estimated 40 years (Friedman, 2020). Those kinds of outsized investments are less likely to go forward in the future, given high breakeven costs, high upfront costs (and the consequent need for financing), and long-run oil price uncertainty.

Existing operations are a different story, with operating costs having fallen significantly to the point where some SAGD operations achieved operating costs of close to CAD 5/bbl, and integrated mining operations (i.e., mining plus oil upgrading) had costs of under CAD 30/bbl (Birn, 2019). Such operations, especially if they have paid off their initial investments, can survive for extended periods of time, even at the kinds of low prices that punished the sector in 2020.

3.2 GHG Intensity of Production

HOW IS GHG INTENSITY RELATED TO THE FUTURE OF THE OIL SANDS?

The GHG intensity of Canadian oil production matters because our trading partners and the international community may, at some point, decide to reward or penalize imports, including oil imports, on that basis. Indeed, some producers and traders are betting on it (Geman, 2021).

GHG intensity also matters because access to capital in the oil sands is affected by global perceptions of our environmental performance (see Section 3.6 on access to capital). To the extent the oil sands are seen by investors as a high-carbon resource, capital in the oil sands from this type of investor may continue to be hard to access (Rystad Energy, 2021).

Finally, the GHG intensity of Canadian oil matters because the public perception of relatively high emissions is a key motivating factor in the widespread protests that have blocked the expansion of pipeline infrastructure for the export of Canadian crude oil, both in Canada and in the United States (Bloom, 2021; Denchak, 2021).

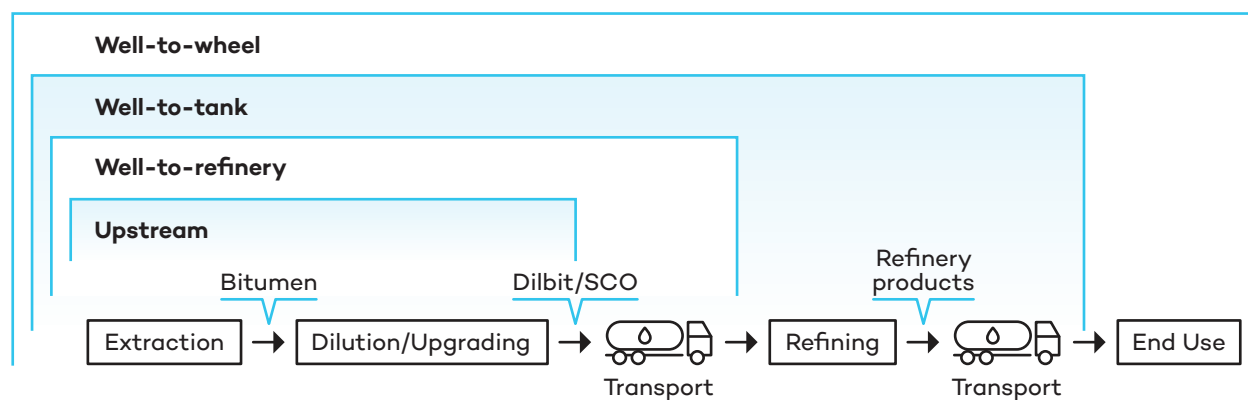
WHAT ARE THE TRENDS IN GHG INTENSITY?

It seems to be a straightforward question: what is the GHG intensity of Canadian oil production, and what are the trends? At the outset, it is important to note that the GHG intensity of Canadian oil production varies widely from operation to operation. It is affected by the methods of production: conventional, in situ, mining, and their various sub-techniques. It varies between new operations and existing ones, primarily because of different technologies employed but also because the more depleted a resource, the more energy per barrel is required for extraction. And it varies according to the characteristics of the specific resource being exploited.



But even accounting for those variations, there are wildly varying answers in the literature to the question: how GHG intense is Canada’s oil production (Dziuba et al., 2020; Israel et al., 2018)? In large part, this is because different analyses are measuring different things. A major factor is scope; GHG intensity can be measured over the entire life cycle, which would include emissions from the final burning of gasoline and diesel in vehicles (well-to-wheels [WTW]), or over parts of that life cycle, as shown in Figure 7.¹⁰

Figure 7. Life-cycle boundaries for estimating GHG intensity of oil production



Source: Sleep et al., 2021.

It is worth noting that emissions from *combustion* (end use) dominate the life cycle, accounting for up to 70%–80% of total emissions (Lattanzio, 2014). Since final use is more or less identical regardless of the source crude, including it (as in WTW) tends to downplay the differences in emission intensity between the various sources and production methods, making Canadian crude look better on average (see Table 5).

¹⁰ Another question of scope is whether to include land-use changes and capital infrastructure (most analyses do not). It also matters how the methodology treats such things as: production of co-products like petroleum coke; allocation of emissions for co-generation; flaring, venting, and fugitive emissions of methane; and operating stage for covered facilities. As well, any analysis has to make assumptions, such as where exported crude is refined.

**Table 5.** GHG intensity, well-to-refinery (WTR) vs. WTW

	WTR		WTW	
	Canada GHG intensity (kg CO ₂ e/bbl)	vs US %	Canada GHG intensity (kg CO ₂ e/bbl)	vs US %
Mining to SCO	163	276%	666	18%
In situ to bitumen	156	259%	664	18%
Mining to bitumen	92	111%	609	8%
In situ to SCO	206	373%	702	24%
Oil sands weighted average	158	265%	664	18%
U.S. conventional crude	43	0%	565	0%

Source: Cai et al., 2015. Note: WTW estimates exclude primary organic carbon and black carbon emissions.

At 63% of total Canadian crude production (Natural Resources Canada, 2020), the oil sands are a key driver of our GHG intensity. Within oil sands production, average GHG intensity varies considerably across the different technologies (see Table 6). At an individual facility level, the spread is much larger, ranging in 2018 from a mined dilbit facility using paraffin froth treatment at 40 kg CO₂e/bbl to a mined synthetic crude oil operation at 119 kg CO₂e/bbl (Birn & Crawford, 2020).¹¹

Table 6. GHG intensity of oil sands by technology

	Average 2018 GHG intensity by technology (kg CO ₂ e/bbl)
Mined dilbit (PFT)	40
SAGD dilbit	65
Mined SCO	89
CSS dilbit	109
Weighted average	72

Source: Birn & Crawford, 2020.

¹¹ The HIS Markit methodology used by Birn and Crawford (2020) focuses on upstream emissions: extraction and upgrading or dilution. Some of that spread would be narrowed after refining, since synthetic crude oil operation requires less energy to refine than does dilbit.



A key interest is in how Canada stacks up relative to its global peers. A seminal bottom-up effort to estimate global GHG intensities focused on WTR emissions (Masnadi et al., 2018).¹² According to that assessment, Canada does very well on one aspect of emissions intensity: methane. Globally, methane accounts for an estimated 34% of CO₂e GHG emissions associated with oil production (Masnadi et al., 2018). Many of the highest-intensity producing countries (e.g., Algeria, Iraq, Nigeria, Iran, and the United States) have high contributions of methane flaring to their calculated GHG intensity (estimated at, respectively: 41%, 40%, 36%, 21%, and 18% of the reported intensities) (Masnadi et al., 2018). If all global production adopted the flaring and fugitive emissions standards of Norway (which has a similar level of performance to Canada) and strong anti-venting policies, annual oil-associated CO₂e emissions could be cut by an estimated 743 Mt, or more than Canada's entire GHG emissions from all sources in 2018 (Masnadi et al., 2018).¹³

Two things about Canada's methane emissions are worth noting. First, Canada's regime for reporting those emissions is rigorous, and the resulting data rates are among the best in the world (Masnadi et al., 2018).¹⁴ Second, as relatively good as Canada's standards are, Canadian producers may be significantly under-reporting. Estimates of oil and gas-related emissions in Alberta and Saskatchewan based on atmospheric methane observation (as opposed to an accounting method) are almost double the figures reported in Canada's National Inventory Report (Chan et al., 2020). It is likely that the accounting methods used outside of Canada are producing similarly skewed results.

Canada's relatively low emissions of methane, however, are outweighed by the large amounts of energy needed for extraction and processing of much of our oil, yielding a relatively high national score for the overall carbon intensity of production. Table 7 shows that Canada ranks fourth globally (among producers with more than 0.1% of global market share) on that metric (Masnadi et al., 2018). Other analyses of upstream emissions come to similar conclusions (Rystad Energy, 2021).

¹² The HIS Markit methodology used by Birn and Crawford (2020) focuses on upstream emissions: extraction and upgrading or dilution. Some of that spread would be narrowed after refining, since synthetic crude oil operation requires less energy to refine than does dilbit.

¹³ Canadian emissions total excludes emissions from land use, land-use change, and forestry.

¹⁴ This does not necessarily mean that the international comparisons cited here are invalid since they rely on a variety of sources to supplement national reporting, on the assumption that most of it will be incomplete.

**Table 7.** Global upstream GHG intensities, by country (2015)

Country	kg CO ₂ e/bbl oil	Country	kg CO ₂ e/bbl oil
Algeria	124.1	Kyrgyzstan	57.6
Venezuela	124.0	Ecuador	57.0
Cameroon	112.3	Argentina	55.9
Canada	107.4	Australia	55.6
Iran	104.4	India	52.5
Turkmenistan	97.2	Turkey	51.5
Indonesia	93.5	Colombia	50.6
Sudan	90.9	Poland	50.2
Mauritania	90.5	United Kingdom	48.6
Trinidad and Tobago	87.3	Angola	45.8
Iraq	86.1	Romania	45.6
Gabon	80.7	United Arab Emirates	43.7
Malaysia	78.8	China	42.7
Nigeria	76.8	Kuwait	42.3
Pakistan	74.7	Qatar	39.7
Ukraine	72.3	Equatorial Guinea	39.2
Oman	71.4	Azerbaijan	38.7
United States	69.0	Italy	37.3
Libya	67.3	Brunei	34.7
Egypt	64.6	Norway	34.2
Brazil	63.0	Ghana	32.1
Chad	62.3	Thailand	31.2
Mexico	60.3	Bahrain	30.9
Russian Federation	59.6	Saudi Arabia	28.4
Kazakhstan	59.3	Denmark	20.0

Source: Masnadi et al., 2018, supplementary materials.

Note: Only includes countries with $\geq 0.1\%$ of global production, calculated on a well-to-refinery basis.



Another assessment focuses on comparing Canadian crude production to U.S. conventional crude production (Cai et al., 2015). The scope is broader, considering WTW, though WTR is also estimated, and emissions from land-use change are included. The analysis estimates emissions for four different oil sands production pathways.

Table 5 shows the results: Canadian oil sands crude was, on average, 2.7 times as emissions intensive as U.S. conventional crude on a WTR basis and 18% more emissions intensive on a WTW basis.¹⁵ As noted above, the broader scope of analysis considerably dilutes the differences in upstream and midstream emissions between Canadian and U.S. crude production. The estimated GHG intensity for Canadian WTR production here is much higher than estimated by Masnadi et al. (2018), in part because this assessment focuses exclusively on non-conventional crude.

To put the numbers into perspective, it is useful to calculate the difference in GHG emissions between the status quo and a hypothetical scenario in which all of Canada's crude was produced at a lower-intensity standard. Table 8 shows the WTR emissions of Canada's 2019 production (4.7 million bpd) at the average intensity estimated by Masnadi et al. (2018) for Canada, compared to the same volume of oil produced at their estimate for global volume-weighted average GHG intensity.¹⁶ The difference is an annual amount of just over 76 Mt CO₂e.

Pundits will argue over whether that is a significant number. At the national level, it represents 10.5% of total emissions per Canada's 2020 *National Inventory Report 1990–2028*, an amount much larger than the emissions of the agricultural sector (59 Mt) or the industrial sector (56 Mt) (Government of Canada, 2020a). From the perspective of the United States, the export destination for our crude and the main locus of concern for the embodied carbon in those imports, our 3.8 million bpd of crude exports represent an estimated 62 Mt CO₂e per year more than would be generated by imports produced at the estimated global average intensity, or roughly 1% of U.S. annual emissions. This number would be higher if U.S. refinery emissions were included since refining dilbit is much more energy intensive than refining conventional crude.

¹⁵ The 17% WTW differential here aligns with the 18% differential estimated by a prominent 2014 U.S. Congressional Research Service survey (Lattanzio, 2014).

¹⁶ The total in this table (184 Mt) seems high, given the reported 2015 emissions for both oil and gas sectors in Canada's *National Inventory Report* are 191 Mt. Part of the explanation may be higher estimates for methane emissions based on satellite data. There may also be differences in scope. Table 8 is not intended as a bottom-up estimate of Canada's oil sector emissions but rather as a rough attempt to contextualize the challenge of oil sector GHG intensity in Canada.

**Table 8.** Hypothetical emissions: Canada's oil produced at global average GHG intensity

	kg CO ₂ e/bbl oil	Canada's total production (2019 MMbpd)	GHG emissions (Mt CO ₂ e/yr)
Canada's upstream GHG-intensity	1074	4.7	184.3
Global volume-weighted average	63.0	4.7	108.1
Differential	44.4		76.2

Source: Author's calculations based on Government of Canada, 2020a; Masnadi et al., 2018.

The trends are toward improvement. Over the last decade, upstream emissions intensity from Canada's oil sands has fallen by 20% (Birn & Crawford, 2020). Almost all of this reduction has been due to increased energy and process efficiency in mining operations; the numbers for in situ have remained relatively flat (Birn & Crawford, 2020)

A 20% reduction in the GHG intensity of oil sands upstream production in a decade is good progress, and BMO predicts another 17% reduction over the next decade (Dziuba et al., 2020). These kinds of improvements, however, look less impressive when put into a global perspective. If we assumed a 20% reduction over the next decade and assume that other producer nations remain at existing intensities, Canada would move from fourth to ninth on the list of significant producers shown in Table 6. At 90 kg CO₂e/bbl, we would still sit 30% higher than average figures for the United States, more than twice as high as Saudi Arabia and almost 3.5 times as high as the world leader, Denmark.

The rate of improvement may well accelerate from the historical trend. There is considerable investment ongoing in low-carbon technologies for in situ production. That is the appropriate target for such investment since the key source of emission reductions to date—mining—is projected to fall as a proportion of total oil sands production from 43% in 2018 to roughly 33% by 2030 (Birn & Crawford, 2020). BMO catalogues a number of promising areas of research and development (R&D) in lower-carbon technologies, including solvent-assisted recovery, greater use of co-generation, non-condensable gas co-injection, and energy-efficiency innovations (Dziuba et al., 2020).

It is, of course, unrealistic to assume that other producers' GHG intensities will stay constant over the next decade. As well as normal expected efficiency gains, we will very probably see the most GHG-intensive producers adopt controls to rein in methane emissions. As noted above, these constitute a large part of the emissions profiles of the highest GHG-intensive producer nations, and the IEA estimates that 40%–50% of these emissions could be avoided at no net cost (IEA, 2017).



CONCLUSIONS

Despite its excellent performance on methane emissions, the continuous improvement in GHG intensity of exploration and production, and the high quality of its data relative to other producers (Masnadi et al., 2018), Canada will very likely continue to be well above average in GHG-intense production relative to its international peers.

What does that mean in terms of the three concerns noted at the outset of this section? First, does it mean Canadian oil will face carbon pricing or other barriers in international trade? That possibility does not seem palpable in the near term. The European Union has committed to enacting a Carbon Border Adjustment Mechanism as a key plank in its European Green Deal, with a proposal coming to Parliament and Council by mid-2021, but it is not a major importer of Canadian crude. Under the new Biden administration, the United States has promised significant action on climate change, including a “carbon-adjustment fee” levied at the border on goods from countries lacking climate ambition. But, as argued in Section 3.1 on U.S. climate policies, this does not seem to be a credible commitment. Prospects are poor for any underlying carbon price against which adjustment could legally take place. As noted in Section 3.1.5, a more credible threat is a U.S. low-carbon fuel standard of the type currently in force in California and Oregon, which penalizes fuels based on the entire life cycle of their GHG emissions.

Finally, the GHG intensity of Canadian crude clearly matters to many of the world’s investors, who are increasingly screening their investments with a climate filter (see Section 3.6). Some argue that this is too narrow a framework for judgment and point out that, on an environmental, social, and governance basis, Canada has an excellent relative profile (Dziuba et al., 2020). While there is merit to that argument, it seems unlikely on its own to stem the tide of divestment. That said, as noted in Section 3.6, while the divestment movement has limited the number of potential oil sands financiers, and this has probably meant increased costs of borrowing or lower share prices, there are still sources of capital for profitable projects.

3.3 Access to Capital

HOW IS ACCESS TO INVESTMENT CAPITAL RELATED TO THE FUTURE OF THE OIL SANDS?

The oil sector is highly capital intensive: extraction, refinement, upgrading, and transport of oil products require initial investments in the range of billions of dollars (CER, 2018a). Annual capital investment in Alberta’s oil sands in the last decade has exceeded USD 30 billion in several years (Birn & Muirhead, 2020). For upstream operations, the majority of that comes from equity investment, with the rest a mix of debt and cash. Anything that affects the availability and cost of those flows directly affects the viability of new operations, expansions, required capital spending in existing operations, and debt-financed day-to-day operations.



WHAT TRENDS AND POSSIBILITIES DO WE SEE IN ACCESS TO INVESTMENT CAPITAL?

Since the oil price collapse in 2014/15 capital investment in the oil sands has been in steep decline (Birn & Muirhead, 2020). Primary among the causes was the explosion of production in U.S. shale, which lowered prices and price expectations. But U.S. shale plays also offered competition for North American investment in a more attractive regulatory and tax environment and in operations that required less upfront capital and offered quicker returns (CER, 2018b; Globerman & Emes, 2019). As of 2018, pipeline capacity constraints added to the unattractiveness of the oil sands as an investment destination (Millington, 2019). The COVID-19 crisis and ensuing price rout turned what was expected to be an uptick in investment in 2020 into another point of decline, with predicted repercussions lasting several years (Birn & Muirhead, 2020). Even before the crisis, the Canadian Energy Research Institute projected capital expenditures at less than CAD 15 billion annually between 2020 and 2024 (Millington, 2019).

Two developments promise to increase the challenge of oil sands access to investment capital. The first is the movement by some major sovereign wealth funds, pension funds, central banks, and investment houses to divest from the oil sands or to filter their investments with a climate lens, demanding, for example, full disclosure of climate-related risks. The list of actors actively divesting over the last year is extensive and includes large pension funds in the United Kingdom, Ireland, Norway, Sweden, and New York; banks such as HSBC, BNP Paribas Group, Norges Bank, ING, European Investment Bank, and France's Société Générale; and institutional investors such as BlackRock and NN Group (Barnard, 2020; Flavelle, 2020; NN Group, 2018; Wittenberg, 2021). As well, several major insurance companies announced plans to divest from and deny insurance to oil sands operations, including AXA, Swiss RE, and Zurich Insurance (Flavelle, 2020). Other investors, primarily Canadian banks, pension funds, and oil patch operators such as CNRL and Husky, have maintained or increased their stakes, believing divestment is swayed by politics rather than economics (Willis, 2019). Some of those are choosing not to divest in favour of transition finance—using their leverage as investors to push for change (Nickel et al., 2021).

One way or the other, the exit of so many investors will necessarily have some impact on the ability to raise funds (Cojoianu et al., 2013). That impact may be more significant for debt financing—of which upstream oil sands operators use less—than for equity finance, on the assumption that there will always be investors with an appetite for what they see as healthy stocks from which others have divested (Fickling, 2019; Thomas, 2021).

However, even “maverick” equity investors will ultimately be influenced, if not by the divestment movement and multi-billion dollar oil major writedowns, which they see as political grandstanding (Healing, 2020), then by the actual performance of assets. Over the last 10 years, the Toronto Stock Exchange Energy Capped Index lost 66.5% (nominal terms), while the Composite Capped Index gained 33.2%.¹⁷ If that discrepancy persists, equity financing, too, may prove challenging.

¹⁷ Based on current-dollar performance of TSX:TTEN versus TSX:TOOC between April 4, 2011, and April 1, 2021.



The other development is the 2019 Supreme Court of Canada (SCC) decision in the Redwater case (SCC, 2019). Redwater was an Alberta oil and gas company that went bankrupt in 2015, leaving a multitude of worthless wells and sites that required abandonment and remediation. The trustee wanted to sell productive sites and argued that it should prioritize repayment of creditors over payment for abandonment and remediation. In 2019, the SCC rejected that argument, holding that the trustee was required to prioritize the fulfillment of its environmental obligations over repayment of debts (SCC, 2019). This alters the financing equation by raising the risk for creditors and may play out in different ways:

- High levels of abandonment and reclamation obligations (ARO) will be factored into the lending value calculation of lenders. A company's ARO was already a factor for lenders; however, they might decide to deduct the company's ARO undiscounted value from its asset value. This would result in "aggressive reductions to lending value" relative to previous calculations, which discount the present value of the ARO to a company's end-of-life reserve amount (Gaston et al., 2019).
- Companies' debt ratios may be recalculated to consider the ARO's present value as debt, and loan agreements will require strict covenants and scrutiny regarding ARO and reclamation practices (Dentons, 2019).
- Lenders may request cash reserves to cover potential reclamation obligations and will increase monitoring and managing of this type of risk (Dentons, 2019).
- Secured lenders may request reporting of compliance with the Alberta Energy Regulator's programs on well abandonment (Dentons, 2019).
- Companies with high AROs and low licensee liability ratings may see depressed stock value, further aggravating the challenge of financing (Gaston et al., 2019).

Coming on top of multiple other "significant economic and political headwinds," the Redwater decision "could create further instability in the lending and investment climate facing the energy industry" (Gaston et al., 2019). Extraction and production companies will be most affected.

CONCLUSIONS

Alberta's oil sands have struggled with low levels of investment since the 2014 oil price crash for reasons that had nothing to do with emissions intensity or investors' environmental concerns: for example, competition from U.S. shale producers, global price movements, and limited export infrastructure. The point of the discussion in this section is that there are recent factors in play that will add additional challenges to financing oil sands operations.

Divestment efforts will probably not pose major hurdles for upstream operators since they operate through the equity finance route, for which alternate investors will always exist. But even there, the reputational damage from public declarations of divestment may be an issue, as may the under-performance of assets over time. The Redwater decision will make finance more difficult in general but will particularly affect firms with significant ARO, making costs and terms of lending more arduous.



More difficult access to finance may not be a critical challenge for the Alberta oil sector in and of itself, but it is nonetheless a challenge that adds one more adverse element to an already difficult environment.

3.4 Government Action on Climate Change Worldwide

HOW IS GOVERNMENT ACTION ON CLIMATE CHANGE RELATED TO THE FUTURE OF THE OIL SANDS?

The United Nations Framework Convention on Climate Change's Paris Agreement commits 190 countries to take action to limit the global average temperature increase to well below 2°C above pre-industrial levels and to pursue even more ambitious efforts to limit the temperature increase to 1.5°C. The latter goal would involve achieving net-zero GHG emissions globally by 2050 (Intergovernmental Panel on Climate Change [IPCC], 2018). Taken seriously, this is a commitment to economic and social change on an unprecedented scale. Given that the combustion of oil results in 21% of total anthropogenic GHG emissions,¹⁸ it is reasonable to expect that global action on climate change will reduce demand for oil. Figure 8 shows the impacts on oil demand, in terms of percentage change from 2010 levels in both 2030 and 2050, of four “illustrative pathways” used by the IPCC to model the implications of a commitment to a 1.5°C temperature increase. All pathways show significant reductions by 2050. Only P4 shows an increase in oil consumption by 2030, but it would be a stretch to call P4 ambitious; it is a “resource- and energy-intensive scenario” involving “greenhouse gas-intensive lifestyles,” a sizable overshoot of the 1.5°C target, and implausibly heavy use of carbon dioxide removal technologies (IPCC, 2018).¹⁹

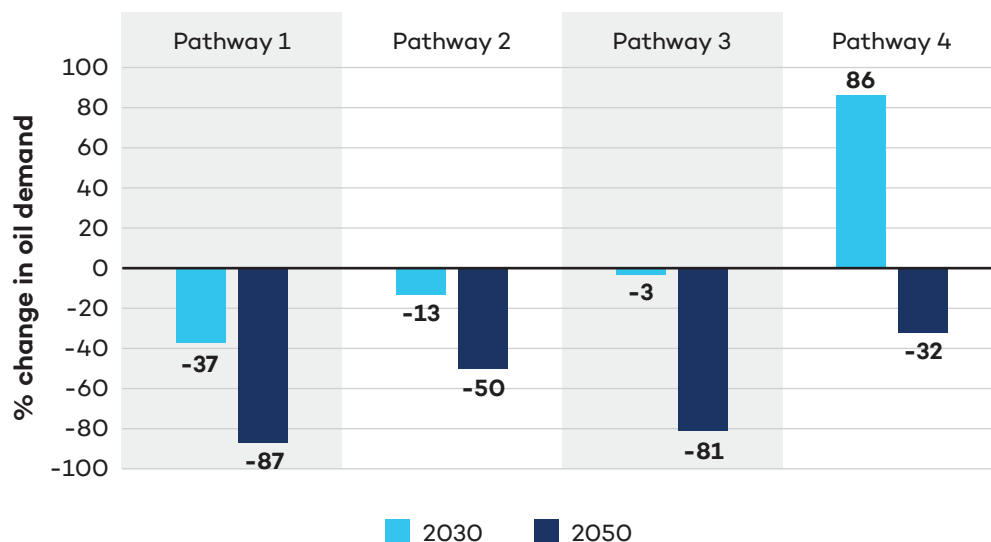
The critical question is: will the Paris Agreement's 190 parties actually take their commitments seriously?

¹⁸ 2018 data for emissions from oil combustion was sourced from IEA, 2020c. 2018 data for total global emissions was sourced from United Nations Environment Programme, 2019.

¹⁹ Under P4, cumulative carbon capture and storage until 2100 would total 1,218 Gt CO₂ or 22 years' worth of 2018-level global emissions, 98% of which is in the form of a single nascent technology: bioenergy plus carbon capture and storage. The needed land area under cultivation for bioenergy crops in 2050 would amount to 7.2 million km² or over 60% of all arable land on earth as of 2015 (World Bank, 2021a).



Figure 8. Change in oil demand under IPCC model pathways to 1.5°C (% , since 2010)



Source: IPCC, 2018, Figure SPM 3b.

WHAT TRENDS AND POSSIBILITIES DO WE SEE IN GLOBAL ACTION ON CLIMATE CHANGE?

There has been an acceleration of government (and private sector) commitments to net-zero pathways in the past two years. As of April 2021, six countries had translated a net-zero target into national law,²⁰ another 26 (including Canada) had proposed putting the target into law in a national policy document, and 15 more had announced a net-zero target as a political pledge for coverage that encompasses 54% of global GHG emissions (Climate Watch, n.d.). Not counted in those numbers is the United States, which is likely to implement a net-zero target under the Biden administration. The EU-27, the United Kingdom, and others have elaborated extensive roadmaps of regulatory and legal instruments, sectoral plans, and timelines for their transitions—a process that others are now emulating. With a legislated carbon price of CAD 170/tonne by 2030 and a raft of regulatory supporting measures, Canada is an obvious example of concrete action in this space.

None of this guarantees that the plans, even legislated ones, will be successful; many key actions will be in the hands of governments that replace those now making commitments. But there are several reasons to believe that the governments of the coming decade will, if anything, intensify the policy response to climate change:

- **Pressure from citizens and the private sector** in the face of climate-related disasters, increasingly erratic weather, and commensurate costs. In the last two decades, relative to the two before that, the world experienced more than double the number of major

²⁰ The six are (as of April 2021): France, Germany, Hungary, Luxembourg, New Zealand, and the United Kingdom (Climate Watch, n.d.).



floods; 6,681 climate-related disasters versus 3,656; 40% higher incidence of storms; and an almost doubling of economic losses from natural disasters, from USD 1.63 trillion to USD 2.97 trillion (United Nations Office for Disaster Risk Reduction, 2020).

- **The falling costs of technological solutions.** As public policy pushes more research and dissemination of technologies to address climate change, costs fall, allowing more ambitious policy in a positive feedback loop. The global weighted average levelized costs of electricity from solar photovoltaic fell 82% between 2010 and 2019, and onshore wind fell 45%, with tens of GW of recent capacity auctions in Asia fetching average prices of less than USD 45/MWh—less than the levelized cost of electricity from low-cost gas-fired generators (International Renewable Energy Agency, 2020). Section 3.3 notes that, even now, the lifetime cost of EV ownership is significantly lower than ownership of an internal combustion vehicle, and the sticker price of EVs is falling steadily. Such trends make it easier to take action, such as, for example, imposing EV mandates.
- **The “paid-rider effect.”** As more and more major economies take ambitious action, the effect is to remove a major barrier for those remaining: the argument that they should not act alone because there are so many free riders on the global stage. It is difficult to persuade people to embrace ambitious but disruptive change if other countries are not doing so, but the flip side is that when a critical mass is paying its fair share, it strongly encourages and enables ambition by others.

CONCLUSIONS

As the costs of inaction (in the form of climate-related disasters and social disruption) continue to rise and the costs of action (in the form of new technologies) continue to fall, it is increasingly likely that governments will respond meaningfully to the challenge of climate change.

Some see the mismatch between current actions and current needs as so significant that strong climate action will inevitably be “forceful, abrupt, and disorderly,” even if delivered as soon as 2025 (Principles for Responsible Investment, n.d.). Modelling the impacts of strong global policy responses produces bleak results for the oil sector. Grant (2020), which assumes an inflection point at 2025 and the compound annual growth rate of oil demand falling by 2.6% thereafter out to 2040, finds a 50% drop in net present value for oil assets that enter production from 2019 to 2025. Additionally, it finds demand drops sufficient to mean almost no new oil fields need be sanctioned post-2030 (Grant, 2020). Their analysis finds that oil sands and shale liquids producers tend to be most vulnerable.

Ultimately, governments will be forced to take meaningful climate action, and that will negatively impact oil producers worldwide. The only uncertainty is whether the transition will happen as a result of timely action, which will impair oil demand, or delayed action, which will impair oil demand through a “forceful, abrupt and disorderly” transition (PRI, n.d.). The latter is a costlier scenario for oil producers—since the risk of asset stranding is increased—and in terms of broader economic and social impacts (Grant, 2020).



3.5 U.S. Energy and Climate Policy

HOW DOES U.S. ENERGY AND CLIMATE POLICY AFFECT THE FUTURE OF THE OIL SANDS?

The linkages start with the fact that 98% of Canada's exported oil goes to the United States, amounting to over 80% of total domestic production (Natural Resources Canada, 2020). From there, the relationship between U.S. environmental policy and demand for Canada's oil gets more complex, with sometimes contradictory effects.

Some policies taken in the United States to reduce the consumption of oil, whether in the transport sector or the petrochemicals sector, could dampen demand or prices for Canadian oil exports in perpetuity. In this section, we look at the possible reinstatement of Obama-era fuel economy standards, for example. However, if U.S. policies weigh heavily on U.S. producers, such as tougher standards for methane leak detection and reduction—also examined below—the effect might be a boon for Canadian producers. If costly U.S. policies are accompanied by some sort of border measures to level the regulatory playing field, the net effect is uncertain.

WHAT ARE THE LIKELY DEVELOPMENTS IN U.S. CLIMATE POLICY?

This section briefly explores the possibilities in five key areas of U.S. climate policy relevant to the oil sector: automobile fuel economy standards, methane regulations, a moratorium on oil drilling on federal lands, border carbon adjustment (BCA), and a clean fuel standard. Most of these are areas in which the new Biden administration could take action without Congressional approval and on which it has signalled intent.

3.5.1 Automobile Fuel Economy Standards

Under President Barack Obama, the U.S. Environmental Protection Agency (EPA) had mandated 5% annual increases in light-duty vehicle emissions efficiency from 2021 to 2026 (IEA, 2020a). The Trump administration reviewed this policy in 2018, originally proposing a freeze at 2020 levels until 2026. In March 2020, after a legal challenge from 23 states, the policy was officially rolled back, with annual increases of 1.5% in efficiency instead of 5% (Shepardson, 2020). On his first day in office, President Biden mandated a review of the Trump administration rules in Section 2 of his environmental Executive Order (Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, 2021). It is likely that the Biden administration will eventually reinstate standards to at least the level of ambition in the original rules, as some have proposed (Moniz, 2020). Others have argued for a slightly less ambitious target, known as the “California Compromise”—the deal struck between California and four major manufacturers (Szymkowski, 2021). What impact would such moves have on U.S. consumption of oil?

The EPA projected that the original Obama-era legislation would shave 1.6 million bpd off crude oil demand in the United States by 2030, rising to 2.7 million bpd by 2050 (EPA, 2010).



These numbers include impacts of both the rolled back 2017–2025 regulations and the 2012–2016 regulations that did take effect and, as such, are higher than the potential impact of a reinstatement of the original rules. The analysis did not disaggregate the two periods.

At least two analyses give implicit projections of what the reinstatement of the 2016–2025 standards would mean by estimating the impacts of the 2020 rollback. Rhodium Group modelled the impacts of the freeze to 2020 levels originally proposed by the Trump administration using three oil price scenarios. They found that by 2025, U.S. oil consumption would increase by 126,000 to 283,000 bpd (Larsen et al., 2018). Assuming no change in standards past 2026, the freeze would cause U.S. oil consumption to increase by 221,000 to 644,000 bpd by 2030. While instructive, that is not a realistic assumption, and the process of setting standards for the years 2027 onwards would almost certainly be put in motion as soon as the new standards are set.

Another estimate from S&P Global indicated that the 2020 rollback to 1.5% would increase oil demand in the U.S. by 500,000 barrels per day (Gordon & Dart, 2020). These figures were based on estimates by the EPA and the National Highway Traffic Safety Administration.

Both of the analyses cited above were conducted based on oil price estimates pre-COVID and are thus likely to be high in the short term. Nonetheless, the range of estimates argues that the potential reinstatement of the Obama-era rules would be significant. To put those figures into perspective: 2019 U.S. demand for finished motor gasoline (excluding E85) in light-duty vehicles averaged 7.1 million bpd (Energy Information Administration [EIA], 2020, Table 36), and Canada's 2019 exports of crude oil to the United States were 3.7 million bpd (98% of crude oil exports) (Natural Resources Canada, 2020). The high-end estimates of impact from above would equate to 9.1% of 2019 national demand in the United States and 17.4% of Canadian imports.

3.5.2 EV Policies

The global uptake of EVs is discussed in depth below, but it is worth briefly noting the policies that the Biden administration will push in promoting EVs, as they will potentially have a much larger impact on U.S. demand for crude than will fuel-efficiency standards.

Biden's American Jobs Plan proposes a USD 174 million investment in U.S. EV manufacturing, working from both the demand and supply sides (Biden, 2021). The proposal includes producer support, point-of-sale rebates to consumers of U.S.-made EVs, incentives to create a national network of 500,000 EV charging stations, and large-scale government procurement for fleets, buses, and service vehicles.

3.5.3 Methane Regulations

The Biden environmental Executive Order (2021) also mandates a review of existing regulations on reducing methane emissions in the oil and gas sectors. In 2019, the Trump administration rolled back 2016 regulations on methane, which had been introduced as part of New Source Protection Standards for the oil and gas industry. Among other things, the 2019 rules eliminated



requirements for methane leak detection and reduction. The accompanying regulatory impact analysis estimated cost savings to oil and gas producers of USD 17 million–USD 19 million per year (EPA, 2019). Those figures are small in relation to the size of the sectors, but the totals mask what would have been uneven impacts, falling disproportionately on so-called stripper wells—wells that produce less than 10 barrels of crude per day. In 2016, marginal wells (most of which are stripper wells) made up 68.5% of all operating oil wells in the United States; in the two decades prior, they ranged from 8%–18% of total U.S. crude oil production (Interstate Oil & Gas Compact Commission, 2016). Compliance costs would have been much higher per barrel for these smaller wells, potentially causing many of them to shut down (Osborne, 2019). If the Biden administration reinstates the 2016 requirements, as has been proposed (Moniz, 2020), the likely result will be decreased U.S. production and potentially increased Canadian crude exports to the United States.²¹ It should be noted that this would not be a “pollution haven” effect; it is widely acknowledged that Canada’s methane regulations are more rigorous than those in force in the United States.

It is entirely possible that the Biden presidency will see new methane regulations that exceed the Obama-era ones (Lavelle, 2020). The latter only covered new oil and gas operations, and increased stringency was foreseen pending results of an EPA assessment of the extent of emissions from existing operations. That assessment was shut down by the Trump administration, but a number of studies since that time have pointed to emissions at a greater scale than had previously been thought (Zhang et al., 2020).

3.5.4 Moratorium on Drilling on Federal Lands

On January 21, 2021, the Biden administration announced a 60-day suspension for oil and gas drilling approvals applying to federal lands and waters. It is expected that this temporary measure will give the administration time to implement a permanent version of this measure, as promised in the Biden campaign for the presidency. Such a move would have varied impacts. Oil production from federal lands currently amounts to roughly 20% of total U.S. production (Osborne, 2021). Offshore production in the Gulf of Mexico would eventually grind to a halt as existing reserves are depleted, and the highly active play on federal lands in New Mexico (65% of state production) would be similarly stifled (Blackmon, 2021; Rystad Energy, 2020a; Tobben, 2021). Texas Permian Basin activity would be relatively unaffected, as it is not on federal land.

The immediate impacts will be muted by the rush of permitting that took place in the months leading up to the election, in anticipation of just such a move by a Biden administration. The current stock of permits, which are unaffected by the suspension, will allow for several years of new drilling on federal lands (Associated Press, 2021). But if the moratorium is made permanent, the impacts would ultimately be significant.

²¹ The Biden climate and energy plan contained no specific commitments to reinstate the 2016 methane regulations, but given that they were implemented when Biden was Vice President, and he was elected with a mandate for action on climate change, reinstatement would not be surprising.



It is also possible that the temporary suspension might lead to a full-scale review of the Bureau for Land Management's leasing program for oil and gas (Wade, 2020). President Obama instituted such a review in 2016 for coal mining, creating a de facto moratorium that lasted years while the review was ongoing; however, unlike an actual moratorium, it required no Congressional approval. A similar move for oil and gas leasing would forestall new wells on public lands.

3.5.5 Border Carbon Adjustment

President Biden's election climate platform contains the following commitment:

As the U.S. takes steps to make domestic polluters bear the full cost of their carbon pollution, the Biden Administration will impose carbon-adjustment fees or quotas on carbon-intensive goods from countries that are failing to meet their climate and environmental obligations. This will ensure that American workers and their employers are not at a competitive disadvantage and simultaneously encourage other nations to raise their climate ambitions. (Biden Harris, 2021a)

Similar language appears in the Biden Industrial Plan (Biden Harris, 2021b), as well as in the U.S. Trade Representative's 2021 Trade Policy Agenda (USTR, 2021). A BCA mechanism, by various different names, is also recommended in the majority staff report of the House Select Committee on the Climate Crisis (2020), the report of the Senate Democrats Special Committee on the Climate Crisis (2020), and the 2020 Democratic Party Platform.

Given that 98% of Canada's crude oil exports go to the United States and the fact that most of that is more energy intensive than U.S. extraction and production (see Section 3.4), does this mean that Canadian oil exports will face border charges implemented during the Biden presidency? Probably not, for two reasons.

First, the U.S. refining sector is designed to consume a significant share of heavy sour crude oil/diluted bitumen. U.S. Midwest refineries are completely reliant on supply from Canada for these feedstocks. Gulf Coast refineries are struggling to access more heavy crude supply from Canada due to the collapse in production from Venezuela and the U.S. import ban, as well as the precipitous decline in Mexican Maya production. It would be politically difficult for any U.S. administration to restrict supply to these refineries. Moreover, oil refining is the very sector that a BCA on oil would ostensibly be aiming to protect.

Second, the levies being proposed do not appear to be legally viable. BCA is an accompaniment to, and adjustment for, domestic carbon pricing (Cosbey et al., 2012). World Trade Organization law may allow that sort of adjustment, but it will not allow adjustment for the cost of non-carbon-price-based regulations (Cosbey et al., 2019). Not only does the United States not have a carbon pricing regime, but it is also highly unlikely that one will be implemented during the next four years. The idea does not appear in any of the above reports or platforms and does not feature in the flurry of early Executive Orders from the Biden administration for good reason: despite



recent high-level calls for it (and an accompanying BCA) (Hillman, 2020), such a tax would be politically unthinkable in the United States, at least for the foreseeable future.

3.5.6 Clean Fuel Standard

Although a clean fuel standard was not proposed by the Biden/Harris platform during the election, there are precedents and lobbying in favour of a national clean fuel standard in the United States, similar to the one currently proposed for Canada (Government of Canada, 2017). A clean fuel standard governs the life-cycle carbon content of transportation fuels such as gasoline by setting declining caps. Compliance is typically possible by finding energy efficiencies in the production of fuel, by blending conventional fuels with low-carbon fuels such as bio-ethanol or bio-diesel, by purchasing credits from cleaner producers, or by purchasing offsets.

California and Oregon have clean fuel standards in place, and as of April 2021, proposals are working through the legislative assemblies of other states such as New Mexico and Washington. A coalition of big biofuel companies in the United States, seeing profitable opportunities for sales in blending, is likely to push a national policy (Renshaw, 2020). And a national policy was suggested by the reports of the House Select Committee on the Climate Crisis (2020) and the Senate Democrats' Special Committee on the Climate Crisis (2020).

As discussed in Section 3.5, Canadian oil sands products are, on average, higher in GHG emissions intensity than those produced in the United States, on a WTR basis (clean fuel standards would not use the more generous WTW life cycle as a basis). Refiners purchasing Canadian crude would therefore face higher costs, and the result could be a discount for Canadian crude. The final result is uncertain, however, since the Midwest and Gulf Coast refiners currently purchasing that product have few alternatives; they are set up to process heavy sour crude, and other sources, such as Mexico and Venezuela, have been in sharp decline.

To give an idea of scale, if a U.S. low-carbon fuel standard were implemented with requirements that equated to a carbon cost of USD 30/tonne, and we used the oil sands-weighted average emissions intensity versus U.S. conventional crude oil production, we would get a penalty per barrel for Canadian oil of just under USD 3.50.²²

CONCLUSIONS

The clearest and most immediate impact of U.S. climate policy would come from strengthening automobile fuel-efficiency standards, which by some estimates could cut U.S. road transport oil consumption in the range of half a million bpd by 2030. This would weaken U.S. demand for refined products and weaken demand for Canadian crude imports. In the longer term, however, U.S. policies to promote EV uptake could have more profound impacts.

A moratorium on drilling on federal lands could have opposite impacts, increasing demand for Canadian crude imports, though it would take several years to play out, as drilling proceeds

²² For the emissions intensity comparison on which this calculation is based, see Table 5.



under existing stockpiled permits and production from existing wells winds down. Strengthened methane regulations could similarly increase demand for Canadian crude imports by rendering marginal well production in the U.S. uneconomic.

However, reductions in domestic U.S. oil consumption or production would not translate one-for-one into reduced or increased exports from Canada. The United States sources about half of its crude oil imports from Canada and half from other producer countries; it is also a major exporter of oil products refined from imported crude. As such, while impacts would likely be significant, final export volumes, and certainly prices, would ultimately depend on more than simply levels of U.S. demand for oil.

A move to implement BCA in the United States is highly unlikely, from both methodological and legal standpoints, unless the United States adopts carbon pricing—an unlikely prospect in the near term. Given that reality, there may be moves instead to adopt stringent low-carbon product standards to protect U.S. industry. If the oil sector were covered under such standards, it would mean increased costs for Canadian producers in reducing emissions, in effect adding to the existing spread between WTI and Western Canadian Select (WCS) prices and dampening Canada's oil exports.

In the medium term, a national U.S. clean fuel standard is a distinct possibility. If it were brought in, its impact on Canadian imports would be a function of the details of the scheme, but however it was elaborated, it would certainly act as a penalty for Canadian oil sands crude oil in the eyes of U.S. buyers. By itself, the level of penalty involved would probably not be particularly significant, but it would still be a negative influence on Canadian export volumes and profitability.

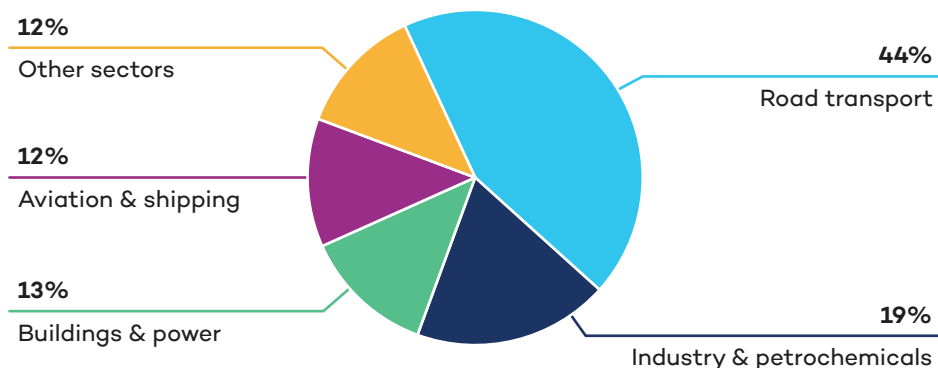
3.6 Uptake of EVs

HOW IS THE UPTAKE OF EVS RELATED TO THE FUTURE OF THE OIL SANDS?

Road transport is by far the biggest component of demand for crude oil. Globally, in 2018, it accounted for 44% of demand, or 42.2 million bpd (see Figure 9) (IEA, 2019). The increased uptake of EVs as substitutes for internal combustion engine vehicles directly affects this major component of oil demand.



Figure 9. Global demand for oil (2018)



Source: IEA, 2019, Table 3.1

WHAT TRENDS AND POSSIBILITIES DO WE SEE IN THE SPEED OF EV DISSEMINATION?

There is no question *whether* EVs will displace internal combustion engine vehicles; the crucial question is *when*. A wide range of estimates exists (see Table 9). Deloitte identifies two broad sets of drivers that will be determinative: (i) customer demand and (ii) policy and regulation (Deloitte, 2019).

**Table 9.** EV dissemination forecasts

Source	Predictions		Impacts
	Sales	Fleet	
IEA Stated Policies Scenario	16% of total sales by 2030	140 million EVs by 2030 (7% of total fleet) 400 million 2- and 3-wheelers by 2030 (40% of total fleet)	Drop in oil demand of 2.5 million bpd by 2030
IEA SD scenario	2- and 3-wheeler sales of EVs are 80% of total by 2030	245M EVs by 2030 (30% of total fleet)	Drop in oil demand of 4.2 million bpd by 2030
BNEF	28% of total sales by 2030, and 58% by 2040	Just under 500 million EVs by 2040 (31% of total fleet)	Drop in oil demand of 17.6 million bpd by 2040
DNV GL	50% of total sales by 2032	By 2050, 75% of total fleet (includes fuel cell vehicles)	
Barclays base case		By 2050, 51% of total fleet	Drop in oil demand of 15.1 million bpd by 2050
JP Morgan	60% of total sales by 2030	By 2030, 18% of total fleet	
Deloitte	70% of total sales by 2030		
OPEC	>40% of total sales by 2045	By 2045, 17% of total fleet	Minimal: Overall road transport oil demand 2.6 million bpd higher in 2045 than in 2019
Bank of Canada		By 2030, 57 million–300 million (4–19% of total fleet)	Every 100 million EVs on the road by 2030 result in drop in oil demand of 1 million bpd, and drop in price of 4%.
RethinkX			Global demand for oil falls from a peak of 100 million bpd in 2020 to 70 by 2030 (40 million bpd below 2017 EIA reference case)

Source: Arib & Seba, 2017; Barclays Research, 2019; Bloomberg New Energy Finance (BNEF), 2020b; Deloitte, 2019; DNV GL, 2020; IEA, 2020a; J.P. Morgan, 2018; Latulippe & Mo, 2019; OPEC, 2021.



In the area of **policy and regulation**, starting in 2016, a growing number of countries and states have announced bans on sales of internal combustion engine passenger vehicles, including Norway by 2025; the United Kingdom, Iceland, Ireland, Netherlands, Sweden, and Germany by 2030; Scotland by 2032; California by 2035; France, Spain, Egypt, Sri Lanka, and Taiwan by 2040. Others have targets—but not laws—for 100% EV sales, such as India’s 2030 target. Canada’s target is 2040, but only Quebec and British Columbia have put targets into law (2035 and 2040, respectively). China, the world’s largest market for EVs, declared in 2020 that all new vehicles sold must be electric, fuel cell, or hybrid by 2035. Some 20 major cities worldwide have announced bans on the use of diesel and gasoline cars (Deloitte, 2019). Some jurisdictions are forcing a transition through efficiency and emission standards. The European Union’s new Euro 7 emission standards will not be met with efficiency improvements alone; they are meant to change the mix of drive trains on the road (Newmark, 2019). As well, many governments offer financial incentives for EV adoption. As of 2018, around one quarter of EV purchase costs globally were covered by government subsidies (IEA, 2018b), and that was *before* governments worldwide pledged hundreds of billions of dollars to green recovery support that includes EV charging infrastructure, consumer rebates, and direct industrial support for the manufacture of zero-emission vehicles. Other governments are employing government procurement and infrastructure spending. As noted in Section 3.1.2, the Biden administration has vowed to replace the entire government fleet (650,000 vehicles) with EVs, saving 375 million gallons (roughly 9 million barrels) of gasoline annually and, perhaps more importantly, to build out a network of charging stations that will rival the number of gas stations currently operating (Biden, 2021; Shepardson, 2021).

In the area of **customer demand**, a 2018 Deloitte survey found consumer concerns on four fronts: driving range, cost premium, lack of charging infrastructure, and time required to charge (Deloitte, 2019). In light of current technological trends, none of these concerns seem significant going forward. Current generation batteries are routinely delivering ranges above 400 km; Mercedes Benz’s 2021 S-class EQS delivers a range of 770 km (Wayland, 2021). Torrents of R&D spending promise to bring a wide variety of different breakthrough battery technologies to market in the coming 5–10 years (The Economist, 2020). Most analysts predict upfront price parity in the early- or mid-2020s. The key factor in that price is the cost of batteries, and that has fallen from above USD 1,100 per kW in 2010 to USD 137 per kW in 2020, dropping 89% in real terms (BNEF, 2020a). While cost reductions will slow as the technology matures (Keen, 2020), at those rates reaching the “magic number” of USD 100/kWh will not take long. Even at current prices, the lifetime costs of EVs are significantly lower than internal combustion engine vehicles, considering fuel and maintenance savings (Harto, 2020; Shahan, 2020). Charging infrastructure concerns are somewhat allayed by increased range but may still be an issue for those unable to install home chargers (apartments, condos). Many governments and private sector actors have announced programs to quickly and substantially ramp up charging infrastructure, but this will continue to be a chicken-and-egg problem in the near term. Charging and battery technology are predicted to be on course to deliver a “consumer-acceptable” half-hour charge (80% capacity to a 60 kWh battery) by 2025 (Deloitte, 2019), but that prediction may already be outdated. Toyota



will unveil a prototype solid-state EV battery in 2021 that can run 500 km and charge in 10 minutes (Nikkei Asia, 2020). BNEF (2020a) expects that solid-state batteries will come in at 40% of the cost of lithium-ion batteries when manufactured at scale.

Not highlighted in the Deloitte survey, but undoubtedly significant, is the range of product choice. The range of EVs currently on offer is a mere sliver of the range for conventional vehicles. This looks set to change quickly. In the past 2 years, most major manufacturers have made pledges to electrify their fleets, including Daimler-Benz (entire fleet by 2039), GM (entire light-duty fleet by 2035), Volkswagen (70 models by 2028), Volvo (all new models electric; 50% of sales electric by 2025), Porsche (50% of the fleet by 2025), and Ford (22 models by 2022).

There are many factors at play, as demonstrated by the diversity of analyst's predictions in Table 9. In one sense, though, there is strong consistency: to date, such predictions have been repeatedly wrong, on the low side. BNEF (2019) catalogues a series of historical estimates from 2016 to 2019, with a clear pattern of repeated upward revisions. Arib and Seba (2017) argue that we are at the edge of the exponential rise in the S-curve of technology adoption for EVs, waiting only for level 4 autonomous capacity to arrive. They argue that when that happens, it will destroy the economics of individual car ownership. They predict a massive and rapid shift to transport as service (ride hailing) instead of car ownership, with essentially all of the fleet vehicles being (significantly cheaper) EVs.²³ In that scenario, while EVs make up only 60% of the global fleet by 2030, they make up 95% of miles driven. The predicted implication is that, by 2030, oil demand will drop from a peak of 100 million bpd in 2020 to 70 million bpd.

In the same vein, it is worth noting that hydrogen fuel cells may have the same sort of transformative effect on the 12% of existing demand for oil in the aviation and shipping sectors, eventually supplying power to trucks, ships, and airplanes. As part of their post-COVID recovery stimulus plans, many countries have pledged enormous support to supply- and demand-side hydrogen R&D (Deign, 2019). Eighteen economies comprising more than 75% of global GDP had rolled out hydrogen strategies as of June 2020 (Eurasia Live, 2020), with Canada following in December 2020.

CONCLUSIONS

It seems likely that the current projections for the speed and extent of EV dissemination will follow the trend of past projections and be proven too timid. One does not have to fully buy into Arib and Seba's vision to believe that a suite of factors is converging to make the coming transformation of automobile ownership non-linear, extensive, and imminent. EVs are a superior product to internal combustion engine vehicles, so when the upfront costs are at parity, the range and charging issues are no longer a concern, and the choice seems less pioneering and more trend-following, the shift will be sudden. The accelerated policy push we see from developed and developing countries alike seems to make such a scenario even more likely. EVs today call to

²³ Lyft has committed to a fully electric fleet by 2030, and Uber has made the same commitment for its fleets in Canada, the United States, and Europe, with the remainder fully electric by 2040.



mind the well-known story of McKinsey's 1985 prediction for AT&T that by 2000 there would be 900,000 mobile phones on the market. In fact, there were 100 million.

3.7 Demand for Plastics

HOW IS PLASTICS DEMAND RELATED TO THE FUTURE OF THE OIL SANDS?

Oil is one of the key sources for plastics feedstock (natural gas being the other). At present, petrochemical feedstocks account for 14% of primary oil demand globally (IEA, 2018a), most of which goes into plastics production. Demand for primary chemicals features prominently in all projections for global oil demand; indeed, they are the most significant factor, followed by trucking and aviation. McKinsey forecasts that petrochemicals could be responsible for 70% of new oil demand growth by 2030 (Cetinkaya et al., 2018). IEA calculates petrochemicals' share of growth to be 50% by 2050 on current trajectories (IEA, 2020b). BP's assumption is even higher at 95%.²⁴

WHAT TRENDS AND POSSIBILITIES DO WE SEE IN THE DEMAND FOR PLASTICS?

IEA's reference case assumes a 60% growth in demand for primary chemicals by 2050 (IEA, 2018a). Barclay's base case scenario sees petrochemicals production increasing by more than 200% by the same date (Barclays Research, 2019). In IEA's Stated Policies Scenario, this means an increase in absolute demand for oil as a feedstock of 4.5 million bpd by 2040, to just over 17 million bpd (IEA, 2020b). Most, but not all, of that would be destined for plastics production.

Plastics demand has, to date, been strongly correlated with growth in GDP, and much of the projected growth in demand is premised on developing Asian economies "catching up" to per capita rates of consumption in Organisation for Economic Co-operation and Development countries (Cetinkaya et al., 2018; Nduagu et al., 2018).

One uncertainty relates to the choice of production method. North American production is currently mostly from crude oil, but cheap shale gas has made natural gas liquids the input of choice for new facilities. The CAD 4 billion Heartland petrochemical complex under construction in Alberta, for example, will use propane from the company's nearby olefinic fractionator. This is in part because North American shale gas is relatively cheap, and it is relatively costly to use heavy oil (the majority of Canadian production) to produce plastics feedstocks.

But even if Canadian oil is not used to produce North American plastics, the use of oil products as feedstock elsewhere (primarily Europe and Asia) means that the demand for plastics will have impacts on global oil prices that ultimately filter back to Canadian producers. Some of that demand might be more direct. A mega-complex of refineries under construction in Northeastern China will handle 1.4 million bpd of crude oil by 2024 (more than the United Kingdom's total refining capacity) in integrated operations designed to produce petrochemicals and plastics

²⁴ Figure derived from BP, 2020 by Bond et al., 2020.



(Bloomberg, 2020). Almost a quarter of that new capacity (327,000 bdp) will be able to use heavy oil as a feedstock (GlobalData, 2020), providing a potential market for Canadian crude if it can get to tidewater via, for example, the Trans Mountain pipeline expansion. There is also Chinese investment, at a much smaller scale for now, in methanol-to-olefins production of petrochemicals—a route that would allow China to reduce its use of imported crude oil and instead use its substantial coal reserves (Ondrey, 2017).

Another uncertainty relates to the speed and force of what seems to be a rapidly growing opposition to plastic in developed and developing countries alike (Bond et al., 2020; The Economist, 2019). Barclays recounts a suite of jurisdictions starting in 2017 that had banned, or proposed bans on, various types of single-use plastics: Australia, Canada, the European Union, India, Kenya, Scotland, Taiwan, Zimbabwe. Since then, the list has grown by leaps and bounds. Barclays estimates, however, that even a complete ban on single-use plastics would reduce total oil demand in their base case by only 5% (Barclays Research, 2019). Others see aggressive recycling efforts/legislation leading to more significant impacts, reducing annual growth in oil demand by from 1–0.5% by 2040 (Bjacek, 2019) and ambitious scenarios leading to peak plastic demand by 2027 (Bond et al., 2020). There are three main routes whereby future demand for plastics could be impaired by an anti-plastic trend: reducing demand through better design and regulation; substituting with other products; and aggressively increasing plastics recycling (Bond et al., 2020). Given the locus of expected demand growth in emerging economies, the key question is whether such efforts will gain traction in those countries.

CONCLUSIONS

Plastics demand out to 2040 is predicted by many to be one of the only growing segments in demand for oil, as sources like road transport decline. Growth in demand in countries like India, China, and Indonesia will be key. In absolute terms, IEA's Stated Policy Scenario predicts increased demand for petrochemical feedstocks of 4.5 million bpd by 2040, most of which would be for plastics (IEA, 2020b).

But those projections are subject to uncertainties. The first is whether oil will provide the feedstocks of choice versus natural gas liquids or coal-derived methanol; this is largely a cost differential question, but most global petrochemical investment is currently geared toward crude as a feedstock. The second is how quickly and seriously the backlash against plastic rolls out or effective recycling schemes are implemented; this is an unknown, but present trends point toward possible substantial disruption, at least in Organisation for Economic Co-operation and Development countries. The key question is whether and when the anti-plastics movement will be taken up in emerging economies. The final result will not likely directly impact demand for Canadian oil but will affect global prices and thus filter back to prices for Canadian producers.

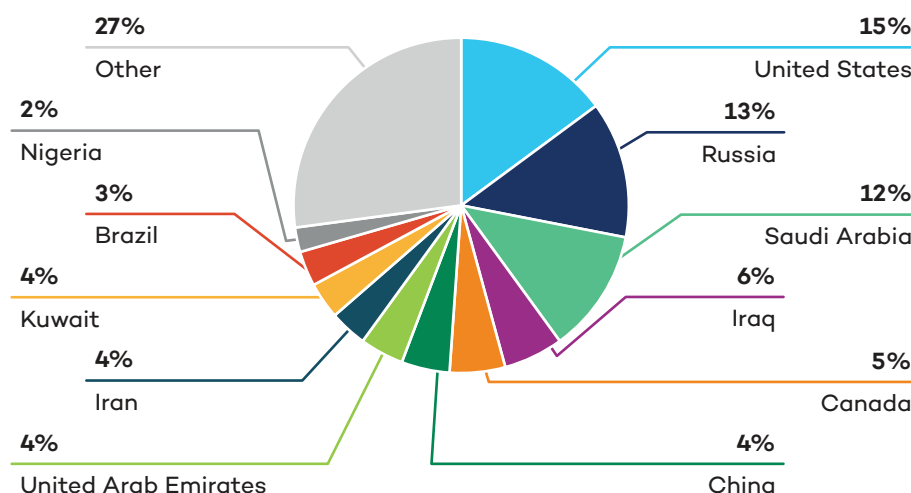


3.8 The Geopolitics of Oil Markets

HOW ARE THE STRATEGIES OF COMPETING PRODUCERS RELATED TO THE FUTURE OF THE OIL SANDS?

Canada may be the world’s fourth-largest producer of oil, but ultimately it accounts for only roughly 5% of total global production and is a price taker (see Figure 10). As such, the decisions and strategies of non-Canadian oil producers have a major impact on global supply and price, as well as Canadian oil sector fortunes. This reality was brought home viscerally by the 2020 Russia–Saudi Arabia schism that saw Saudi Arabia fail to support oil prices in the face of the COVID-19 crisis demand crash (Thompson, 2020), bringing oil prices to historic lows and wreaking havoc in an already suffering Canadian oil patch (Masson & Winter, 2020; Sukhankin, 2020).

Figure 10. Global oil production shares by country (2019)



Source: EIA, 2021.

WHAT ARE THE LIKELY DEVELOPMENTS WITH RESPECT TO THE STRATEGIES OF COMPETING PRODUCERS?

We have a reasonably good idea, based on history and ongoing investments, how Canada’s competitors will behave in situations of market stability. More interesting is how they will behave in times of crisis. In the context of this report, the most interesting question is how they will behave as the world transitions to a low-carbon economy and demand for oil begins to decline (Fattouh et al., 2019). Predictions vary on when global oil demand will peak, but when it does, it will put pressure on producers with downward pressure on prices. A similar dynamic will play out if carbon pricing is more widely adopted at levels of stringency that increase over time, as Canada’s does. Other things being equal, higher future carbon taxes mean lower future returns to hydrocarbon producers and lower production levels.



The latter is the starting assumption for a dynamic first proposed in 2012 by Hans-Werner Sinn: the green paradox. It predicts that increasing carbon taxes will decrease the expected value of future reserves relative to current reserves and boost near-term production of fossil fuels, at least in part defeating the intent of the original tax (Sinn, 2012).²⁵ Though critics point out that some of the assumptions, like easy intertemporal production shifts, are unrealistic (Cairns, 2014), the theory is more compelling in the long run. Could such a dynamic prevail if producers expect the value of future reserves to be lowered not only by carbon taxes but also by secular decline in demand?

Of course, such a strategy would only work if the price drop it would trigger (from increased production) left producers better off on a present-value basis than they would have been simply holding the course. Some suggest that this might be true for very low-cost producers, such as Russia and Saudi Arabia (El Gamal et al., 2020). Fattouh (2021) argues that such a high-investment, high-output response to the energy transition is probably not a viable strategy, even for producers like Saudi Arabia, for at least two reasons: first, it may end up causing significant stranding of resources, and second, the Saudi economy and government finances are simply too dependent at present on oil revenues to deliberately trigger such a price decline. Saudi Arabia's unexpected move in January 2021 to voluntarily cut oil supply by an extra 1 million bpd demonstrates its dedication, at least for the moment, to a stable high-price market (Blas et al., 2021).

In the medium to long term, however, Saudi Arabia is aggressively pursuing a diversification strategy (Oxford Business Group, 2019; Tong, 2019) that may change that calculus, though it would have to involve a change in trajectory from ongoing diversification efforts that have been marginally successful since the 1970s. Russia already has a relatively diversified economy, a floating exchange rate, and control over popular dissent, making it able to withstand prolonged periods of oil prices as low as USD 25/bbl (Paraskova, 2020).

For those two countries, however, the decision to ramp up production is not just a matter of the green paradox but also, probably more importantly, a strategic decision about market share, especially with respect to U.S. shale producers. The rise of U.S. shale and its successful capture of global market share gave rise to the disastrous Saudi and Russian effort in 2014 to undermine U.S. production with low prices—a move which led to the longest-lasting oil price depression since the supply-driven collapse of 1986 (Stocker et al., 2018). In the face of declining demand from the COVID-19 crisis in March 2020, OPEC+ solidarity broke on Russia's desire to damage U.S. capacity with low prices²⁶ and Saudi Arabia's reluctance to follow that course. Saudi Arabia's response to the rift—to boost supplies in a show of market power—led to an unprecedented oil

²⁵ This is an extension of Hotelling's Rule, which assumes that producers of an exhaustible natural resource will produce at levels that equalize the present value of marginal returns from the resource in each future time period, taking into account expectations of production costs and taxes. Increasing future taxes then tilts production toward the present and away from the future (Hotelling, 1931).

²⁶ Russia also had political motives for punishing the United States: revenge for U.S. sanctions against Rosneft and for U.S. obstruction of the Russian Nord Stream 2 gas pipeline to the European Union (Sukhankin, 2020).



price rout that deeply underscored the potential for all producers to suffer under a deliberate high-supply policy.

On the other hand, some suggest that the Saudi Arabian–Russian split in 2020 was a “masterstroke” from a game theory perspective, arguing that it is in the interests of a low-cost dominant monopoly for the market to cycle from high to low, with the highs big enough to encourage investment by the “competing fringe” high-cost producers and the lows bad enough to then turn those investments bad (Halff, 2020). If that theory is correct, we might expect to see more cyclical swings in a scenario of declining demand and low oil prices. In such an environment, the competing fringe is more easily damaged.

Such a dynamic may be a more legitimate concern than the green paradox. The recent price crash drives home the reality that oil demand is relatively price inelastic—that it does not take much of an increase in supply to drop prices significantly (Krichene, 2002; Labandeira et al., 2017). So critics of the green paradox theory argue that a rush to liquidate by major producers would be very costly (Cairns, 2014). As well, the realities of oil production—oil wells and fields have a high rate of production initially and then a steep natural decline in productivity—mean that ramping up production from existing facilities is not usually possible (Jakobsson et al., 2012). These characteristics of the oil sector mean that the theoretical green paradox effect may not manifest strongly in reality, at least in the short run (Bauer et al., 2018; Cairns, 2014).

Notwithstanding, there are a few avenues by which a green paradox-like dynamic might manifest in the medium term:

- As Saudi Arabia progresses toward economic diversification, it may behave more like Russia in terms of appetite for strategically low oil prices. This is unlikely for at least the next decade and probably longer.
- Oil price outlooks may be low enough on a sustained basis to convince Saudi Arabia and Russia that a low-price strategy could permanently shut in significant capacity in U.S. shale. In other words, they might revise their market share strategies when faced with a secular decline as opposed to a cyclical decline.
- In the face of expectations for sustained low prices or secular decline, OPEC and OPEC+ solidarity would be tested by the “prisoner’s dilemma”: if a given producer believed that enough other producers would break ranks and ramp up current production, then it would make sense for that producer to do so as well; the risk is that all would pile in, even though it would leave them all worse off than they would be in a functioning cartel. This dynamic is not new; it has defined OPEC from its founding, and many members are currently desperate to use oil revenues to rebuild economies ravaged by COVID-19, conflicts, sanctions, and other shocks (Blas et al., 2020; Lee, 2020; Smith et al., 2020). But a world of declining oil prices would ratchet those tensions to new levels.



CONCLUSIONS

These types of scenarios are necessarily plagued with uncertainty. In the first place, we do not know when global demand for oil will peak (some scenarios assume that it already has [Bond, 2020; BP, 2020]). Neither do we know how international producers will react to the prospect of lower demand and prices after the peak or what strategies they will assume others will adopt. While the COVID-19 crisis and other crises give us some insight, none of them have involved a secular decline of demand—a fundamentally new type of crisis. This prospect will likely bring unprecedented pressures to bear on OPEC+ as it tries to support and stabilize prices.

The worst-case scenario for Canadian producers is a demand peak that arrives soon, or has arrived, followed by a strategic rush to extract—a failure of OPEC+ to preserve prices in a dynamic that feeds on itself. Any such “rush” would be limited by the realities of oil production that make it difficult for most producers to ramp up supply in the short term but would also be amplified in terms of price impacts by the inelasticity of demand for oil.

Another scenario could see a declining market driving cyclical price swings through alternating liquidation of reserves and curtailment/correction as the uncoordinated strategies of individual producers collectively overshoot their intended results. A declining market would also make it more attractive for dominant low-cost producers to spark or amplify such boom-and-bust cycles in a strategic effort to force out high-cost competition.

These are only possibilities, but they inform a worrying prediction: when peak demand is eventually passed, the path thereafter will not likely be an orderly decline of prices in a stable but shrinking market.

3.9 Summary of the Drivers Analysis

It is not a simple matter to distill the big picture from the various drivers surveyed in this section. Many of them are interdependent. For the future of oil as an economic driver for Alberta and Canada, they contain a mixed bag of positive prospects, negative prospects, and uncertainties.

POSITIVE PROSPECTS FOR ALBERTA'S OIL SECTOR:

- GDP and population growth are on track to create a new customer base for plastics in emerging economies, driving growth in demand of several million bpd of crude out to 2040 at least, as well as providing Asian customers for Alberta's heavy crude if it can get to tidewater in greater volumes.
- New methane reporting rules in the United States might increase demand for Canadian crude by shutting in many smaller (stripper) wells.
- The prospect of a U.S. BCA affecting Canadian crude exports is remote.
- The divestment movement may slightly increase the costs of capital—especially debt—to oil sands operators, but the majority of upstream investment is equity, and that is unlikely to face a crunch unless long-term underperformance of assets becomes an issue.



NEGATIVE PROSPECTS FOR ALBERTA'S OIL SECTOR:

- Global uptake of EVs is likely to reach a tipping point in the near future as costs fall, performance improves, and charging infrastructure is built out. Sales and fleet penetration will probably make current predictions laughable in retrospect. With road transport being the biggest market for crude oil, impacts on demand will be significant.
- The tightening of U.S. auto efficiency standards is a certainty and will take a significant chunk out of U.S. demand for fuel.
- The Redwater SCC decision will make access to capital more difficult for Canadian oil producers, with heavier impacts on smaller operators and those with high ARO.
- GHG emissions intensity in Canadian production will continue its downward trend, especially in mining, but that will not make much difference in the GHG intensity of Canadian crude relative to foreign production. It will not placate protestors and investors that focus on that differential.
- Global climate action by major economies seems to be going beyond nice words and platitudes, and that dynamic will be reinforced by the increasingly costly impacts of climate change, falling costs of technical solutions, and the “paid-rider” effect. As a result, the climate-ambitious scenarios in outlooks by agencies such as the IEA, the EIA, and the CER look increasingly likely, and the reference cases are an inappropriate basis for planning.

UNCERTAINTIES:

- Demand for plastics, which is the only growing component of global oil demand in most scenarios, will depend fundamentally on how much and how quickly the anti-plastics movement gains traction in emerging economies like China, India, and Indonesia.
- Increased pipeline access for exports, via the Line 3 replacement to the U.S. Midwest and the Trans Mountain Expansion to the Canadian west coast, would likely improve prices for Alberta's heavy crude. But it is uncertain whether those lines will be completed.
- It is unclear how the geopolitics of oil markets will play out. In the first place, it is unclear when peak demand will be reached. When it is reached, it is unclear how low-cost producers and market influencers like Saudi Arabia and Russia will react—whether a green paradox dynamic will prevail or whether they will act strategically to permanently damage competitors like the U.S. shale producers. It is likely that in the face of secular declining demand, the strategies will change, the cohesion of OPEC+ will be eroded, and the result will increase market instability and price volatility.

On balance, there are more challenges than opportunities here for Canadian oil producers, and in particular for Alberta's producers of heavy crude. The bigger picture is still uncertain, but it is likely to be one of lower demand and prices with more difficult access to capital than was envisioned even a few years ago.



4.0 Scenarios for the Future

This section focuses on two possible future scenarios, modelling what they would mean for the ability of the Canadian oil patch to drive future prosperity. The focus is specifically on Alberta, as the home of over 80% of Canadian oil production, but the results are relevant to Canadian oil more generally. The two scenarios are:

1. **Low and flat oil prices from the present to 2050.** After a relatively quick recovery from the current crisis, oil prices are flat in the long run at USD 55/bbl. Oil price forecasting on those time scales is a fool's game, and our scenarios are not intended to be predictions. Rather, they show the kinds of impacts we could expect if future prices were not as rosy in the long term as had commonly been predicted pre-2020. This price scenario is in line with various climate-ambitious scenarios produced by other analysts. While we characterize it as “low,” in light of the full slate of drivers surveyed above, it might be better characterized as mid-range.
2. **Oil prices follow historical cyclical swings.** This scenario uses the same average long-term oil price as the first scenario but subjects that price to cyclical swings. As shown below, such swings are the historical norm, as they are for many commodities (though in the oil sector, they may be becoming more pronounced over time). The question is what it means for Alberta's prosperity, as measured by indicators like GDP, employment, and investment, if we do not model a smooth curve that inherently averages swings over time but instead explicitly builds cycles into future prices.

We use an economic and energy model of the Canadian economy to track the impact of oil prices on macroeconomic outcomes, including GDP, investment, and employment. The economic model used, gTech,²⁷ is calibrated to historical energy and economy data for all Canadian provinces and territories, with all 13 provinces and territories, including Alberta, modelled as separate yet integrated regions. A rich and diverse oil and gas production sector is represented to reflect current and possible future production characteristics for multiple sectors, including natural gas extraction (conventional, tight, and shale); light and heavy oil extraction; oil sands in situ and mining; and upgrading (merchant and integrated). New producing capital stock is added in the model as supply conditions improve project economics; conversely, investment decreases when returns to investment fall. Investment to replace retiring capital stock is also tracked in the model. Upstream supply and the accompanying capital investment are linked to global and U.S. energy prices and domestic and global end-use demand. The U.S. economy is modelled as an integrated region with energy trade calibrated to historical data.

²⁷ gTech is a computable general equilibrium model operated by Navius Research. The model is used extensively by Canadian provinces and territories to assess energy and carbon policy. For more information, see: <https://www.naviusresearch.com/gtech/>



As the model steps out to 2050 in the simulation, energy supply and demand interact across all sectors and regions, such that markets for commodities, labour, and capital all clear in a new equilibrium. Changes in key indicators—GDP, investment, and labour—are then tracked, and comparisons are made between the two scenarios.

4.1 Modelling Exercise 1: Low oil prices

The previous section surveyed multiple drivers for trends and found reason to doubt the likelihood of high-price scenarios out to 2050. This first modelling exercise asks: what if the drivers surveyed in the previous section validate the more pessimistic projections and scenarios? And what if oil prices do not return to meet the pre-pandemic expectations?

Our reference case for this exercise is a pre-2020 prediction of a steady USD 70/bbl (WTI) oil price out to 2050. This is taken from the *Canada's Energy Future 2019* reference case published by the CER (2019). This is our assumed pre-pandemic expectation.

Our low-oil-price scenario, which we contrast to the reference case, is a future based on BP's forecast of an average price of USD 55/bbl (Brent crude, 2020 USD) going out to 2050 (BP, 2020).²⁸ This is a lower price scenario than many—but not all—industry scenarios and predictions (see Table 10, Figure 11).

²⁸ We compare the reference case and the scenario directly, meaning we assume zero spread between Brent and WTI prices.

**Table 10.** Oil price scenarios and predictions (USD/bbl)

	2020	2025	2030	2035	2040	2045	2050
CER 2020 (evolving) ^a	37	52	55	55	54	51	50
CER 2020 (reference) ^a	37	70	75	75	75	75	75
EIA 2021 reference case ^b	39	59	71	77	84	88	91
EIA 2021 high price ^b	39	113	132	137	148	159	168
EIA 2021 low price ^b	39	34	35	39	41	43	46
IEA 2020 stated policies ^c		71	76	81	85		
IEA 2020 sustainable development ^c		57	56	54	53		
BP 2020 ^d	55	55	55	55	55	55	55
Total 2020 ^e	35	63	65	60	57	52	50
Shell 2020 ^f	35	56	52	48	45	41	38
Low-oil-price scenario	48	55	55	55	55	55	55

Notes:

a Brent, 2019 USD (CER, 2020).

b WTI, 2020 USD (EIA, 2021).

c Import country average, 2019 USD. Sustainable development scenario values for 2030 and 2035 are imputed (IEA, 2020b).

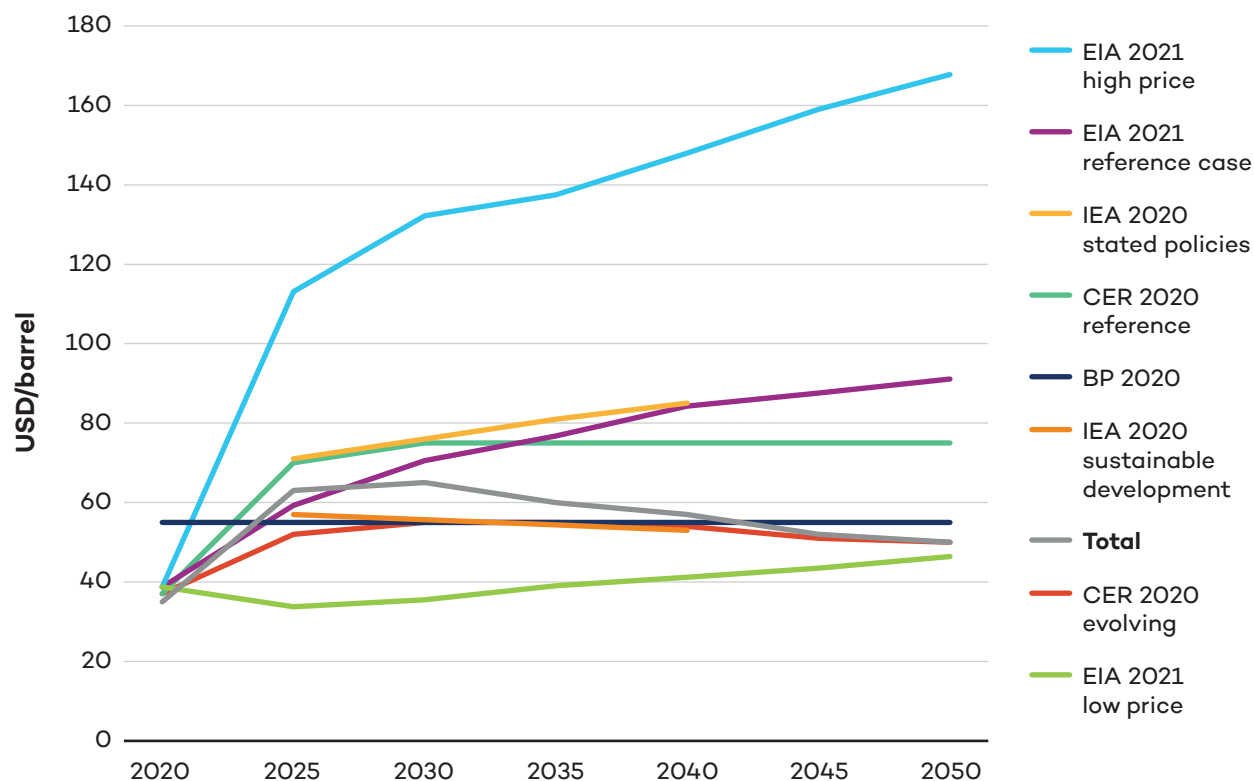
d Brent, 2020 USD. Note that the actual projection is an average of USD 55/bbl (BP, 2020).

e Brent, 2020 USD. Mid-year values imputed (Total, 2020).

f Brent, converted from current to 2020 USD at an assumed 1.5% annual rate of inflation (Shell, 2020).



Figure 11. Oil price scenarios and predictions (USD/bbl)



Source: Based on data in Table 10.

4.1.1 Modelling Results: Low oil prices

As might be expected, a lower price for oil has negative impacts for Alberta, both in terms of impacts in the oil patch itself and in terms of the wider provincial economy. In the oil and gas sector (see Table 11), the low-oil-price scenario shaves 5.2% off the annual contribution to Alberta’s GDP relative to our reference case, or an average of CAD 4.4 billion per year between now and 2050. Other indicators are similar. Employment in the oil and gas sector drops 4.5% per year, for an average of over 6,300 FTE jobs out to 2050. Investment drops 5.3%, or just over CAD 2 billion per year, and royalties drop by 34.7%, or an average of just under CAD 2 billion per year.



Table 11. Impact on the oil and gas sector of a change from the pre-COVID-19 oil price of USD 70 to a post-COVID-19 oil price of USD 55

Economic indicator	Metric	Average annual 2020–2050 reference case value	Change from reference case %
Output	Billion USD	122.90	-5.24%
GDP	Billion USD	84.60	-5.24%
Employment	Full time equivalent jobs (thousand)	142.6	-4.45%
Investment	Billion USD	\$38.90	-5.28%
Royalties*	Billion USD	\$5.60	-34.70%
Emissions	MtCO ₂ e	122	-5.31%
Emission intensity	tCO ₂ e/USD 1,000	1.443	-0.07%

* Royalties include only estimated royalties for oil sands production and not royalties from conventional oil and gas production.

Source: Navius modelling. Figures do not include upgrading and refining sector impacts.

The impacts on the broader Alberta economy reflect the fact that oil and gas are a major part of the provincial economy, so impacts there have indirect and induced impacts more widely. Table 12 shows those effects.

Table 12. Impact on Alberta's economy of a change from a pre-COVID oil price of USD 70 to a post-COVID oil price of USD 55

Economic indicator	Metric	Average annual 2020–2050 reference case value	Change from reference case %
Output	Billion USD	845	1.29%
GDP	Billion USD	510	-0.68%
Employment	FTE Jobs (million)	3	0.06%
Provincial Taxes	Billion USD	57	-1.73%
Federal Taxes	Billion USD	78	-1.77%
Investment	Billion USD	101	-2.89%

Source: Navius modelling.



GDP in the broader Alberta economy compared to the reference case is down by an average of 0.68% every year out to 2050, or roughly CAD 3.5 billion per year. Employment numbers are slightly positive. Both of these numbers are more positive than the impacts in the oil and gas sector alone since the decline in the oil sector opens up employment opportunities and economic activities in other sectors (see Figure 12).

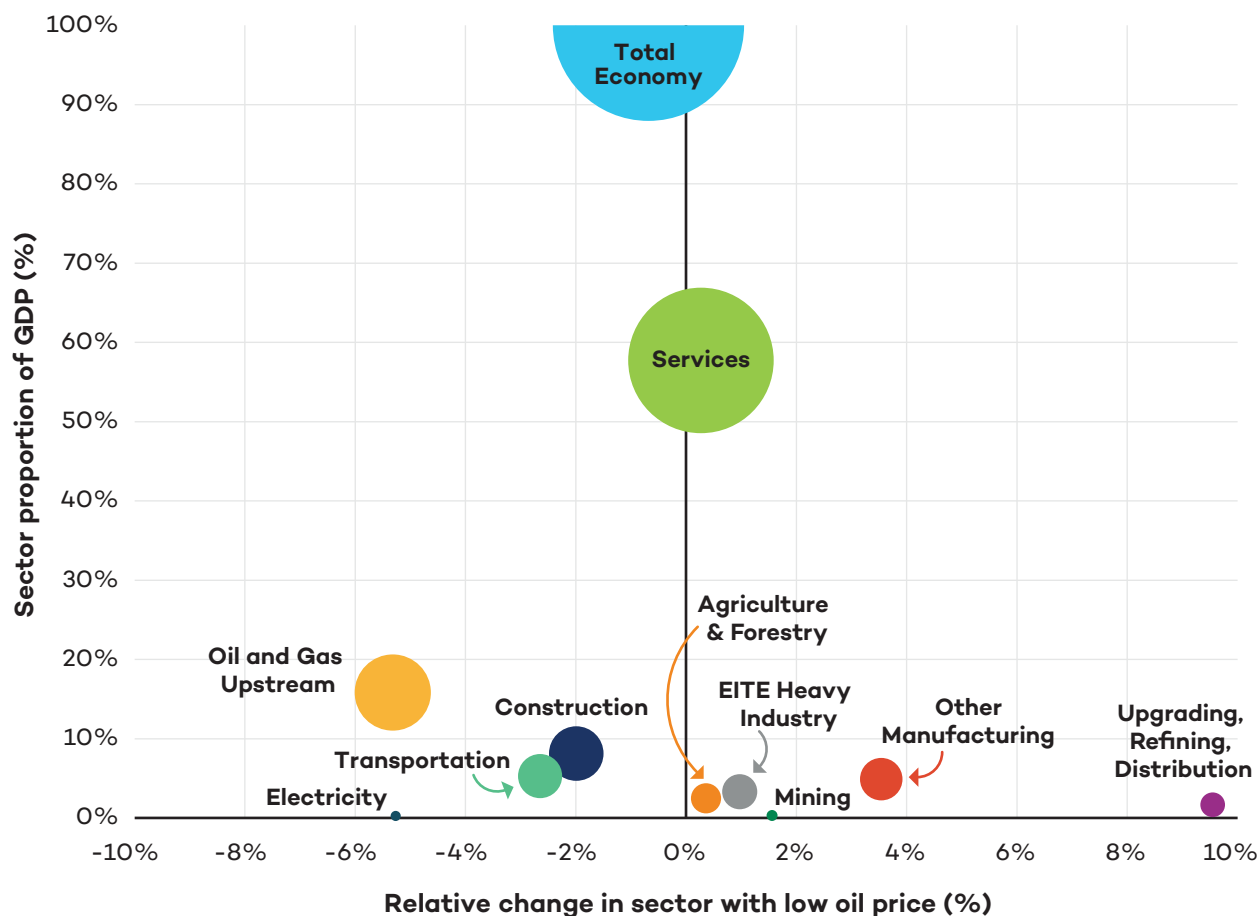
Investment in the broader Alberta economy drops by more than the drop in oil and gas alone by an average of 2.9%, or 2.9 billion per year over the period. Provincial and federal taxes are also down by an average of 1.7% and 1.8%, respectively, or just under CAD 1 billion and CAD 1.38 billion per year, respectively.

As noted above, the result is a shift in the composition of sectors that make up Alberta's economy. Figure 12 shows the size of each sector affected (the size of the bubbles) and the growth or decline (movement to the right or left, respectively) of Alberta's major sectors. Upstream oil and gas take the biggest hit, understandably, as do sectors closely linked to the oil patch: construction and transportation services. Other services, such as energy-intensive trade-exposed heavy industry and mining, show a slight boost, in part from freeing up oil sector workers. A surge in merchant upgrading, propelled by both new investment and the ramping up of current capacity, drives the growth in upgrading, refining, and distribution, at almost 10%.²⁹

²⁹ We recognize this surge in production in a low-oil scenario is a counterintuitive result. It is driven by low relative costs for labour and materials in Alberta under the depressed oil price—there is low-cost capacity to expand upgrading relative to the United States. While this dynamic is reasonable, we think the modelling result is overly optimistic about the strength of this response and the ability to both ramp up current capacity and, more importantly, build new capacity.



Figure 12. Sectoral change: Relative change in average annual GDP between 2020 and 2050 with a USD 70 oil price change to a low USD 55 oil price (%)



Source: Navius modelling.

4.2 Modelling Exercise 2: Volatility

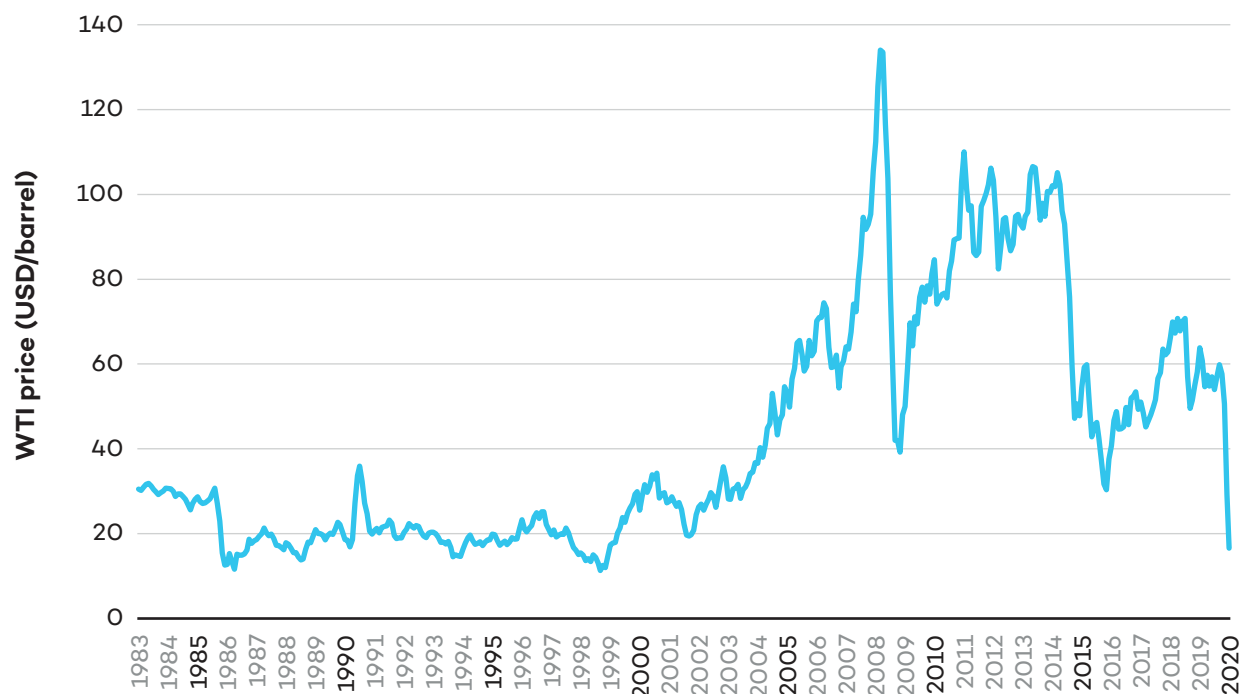
The current crisis in the oil patch defies precedent. However, oil price shocks, in general, are not uncommon. While there have been some periods of relative price stability over the last 40 years, in general, both the frequency of price shocks (the number of months between significant events) and the magnitude of price shocks (the drop or rise in price as well as the time to recover to pre-existing levels) have been increasing. This price volatility clearly has impacts on investment in the oil and gas sector in Alberta and alters other outcomes for Albertans, such as employment income.

To assess the impacts of price volatility on economic outcomes, we created two deterministic price shock scenarios that varied the future oil price to capture observed long-term trends in price volatility. To determine the range of oil price volatility to model, historic oil shocks were examined over the last 37 years to look at the magnitude and probability of events occurring at any given



time. A total of 17 different shock events over the time period revealed that the frequency and magnitude of these price shocks have been increasingly prevalent (see Figure 13).

Figure 13. Historical oil prices for WTI (USD/bbl)



Source: Government of Alberta, 2021b.

This historical data was used to develop two oil price shock scenarios with 5-year average prices deviated to represent the observed distribution of price volatility. Using monthly historical WTI oil prices, the distribution of 5-year oil prices from the average linear price trend over the whole time series was determined. From this data, the distribution of oil prices from a long-term average price trend was expressed.

While the range in price volatility and timing of price shocks varies between the two scenarios, they both reflect an uncertain price future compared to a typical forecast reference case of price stability. In both scenarios, the long-term average cost is set to USD 55/bbl to allow for a direct comparison with the post-COVID oil price scenario discussed above.

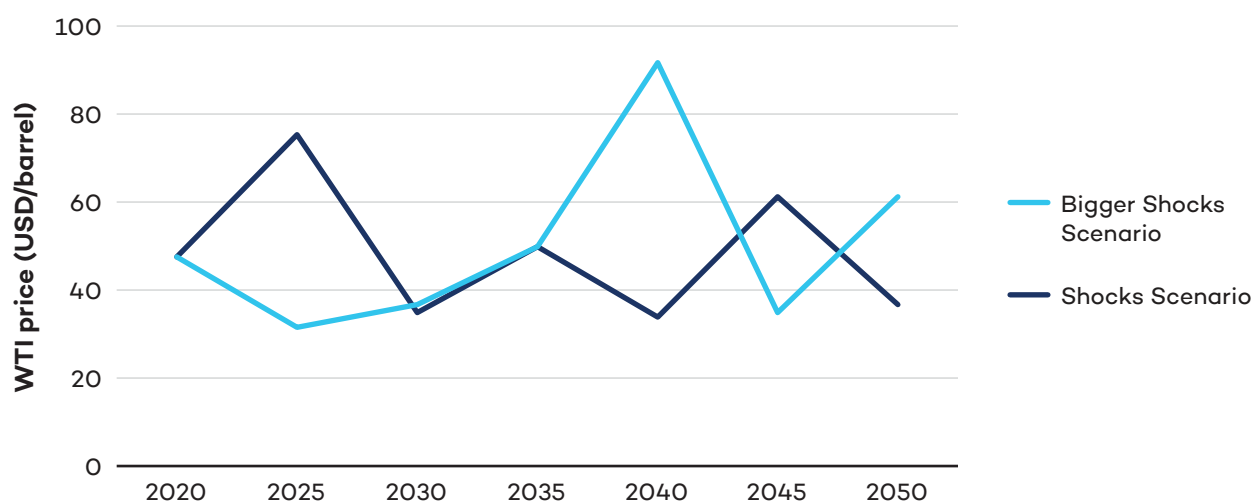
- **Reference case:** Our reference case is close to the low-price scenario described in modelling exercise 1. It assumes a constant WTI price of USD 55/bbl out to 2050.
- **Shocks Scenario:** This oil price shock scenario was built using the 20th, 30th, 40th, 60th, 70th, and 80th percentile price distributions. Each of the 5-year percentile changes in oil price was applied randomly to one of the six 5-year forecast periods (2025, 2030, 2035, 2040, 2045, and 2050). This symmetric sample is intended to model a reasonably representative uniform price distribution representing both lows and highs from the WTI



USD 55/bbl flat price and ultimately resulting in similar average oil prices over the whole time period. The oil price climbs to highs of USD 75/bbl in 2025 and USD 61/bbl with lows in the mid-USD 30s.

- **Bigger Shocks Scenario:** The oil price shock uses a somewhat wider price distribution, applying the 10th, 30th, 40th, 60th, 70th, and 90th percentile price distributions. Each of the 5-year percentile changes in oil price was applied to one of the six 5-year forecast periods (2025, 2030, 2035, 2040, 2045, and 2050). The oil price hits a low of USD 32/bbl in 2025 but then works up to a high of USD 92 in 2045.

Figure 14. Assumed WTI oil prices in two shocked scenarios (USD 2015)



Source: Navius modelling.

4.2.1 Modelling Results: Volatility

Although the modelling is limited to only two oil price shock scenarios and does not include a large range of scenarios to evaluate the probability and magnitude of different outcomes, the developed price shock scenarios provide a directional view of impacts in comparison to most modelling, which is conducted with stable and non-volatile price assumptions.

In terms of impacts on the oil and gas sectors, Table 13 shows their GDP contributions in Alberta drop by an average of 21% and 19% per year out to 2050 compared to the reference case, or an average of CAD 24.3 billion and CAD 21.8 billion, in the Shocks Scenario (SS) and the Bigger Shocks Scenario (BSS) respectively. Sectoral output drops by 20% (SS) and 17% (BSS) over the time period, with resulting negative impacts on employment—an average drop of 24,300 (SS) and 21,800 (BSS) full-time positions annually—and royalties, which are particularly strongly affected, with drops of 43% (SS) and 41% (BSS). Investment sees an average annual drop of 30% (SS) and 26% (BSS) compared to the reference case, or an annual average impact of CAD 11.2 billion (SS) and CAD 9.6 billion (BSS).



Table 13. Oil and gas economic indicators comparing the reference case to the shocked scenarios

Indicators	Metric	Reference case values (flat USD 55/bbl)	Change from reference case			
			Scenario 1: Shocks	Average annual impact	Scenario 2: Bigger shocks	Average annual impact
GDP	Billion USD	80.20	-21%	-\$24.3	-19%	-\$21.8
Output	Billion USD	116	-20%	-\$15.9	-17%	-\$13.4
Employment	FTE (000')	136	-21%	-24.3	-19%	-21.8
Investment	Billion USD	36.9	-30%	-\$11.2	-26%	-\$9.6
Royalties*	Billion USD	3.66	-43%	-\$1.58	-41%	-\$1.50

* Royalties include only estimated royalties for oil sands production and not royalties from conventional oil and gas production.

Source: Navius modelling.

It is noteworthy that some impacts in the BBS are less severe than those in the SS. This is driven by the former's high swing to positive (USD 92/bbl) toward the end of the period.

The impacts of volatility at the provincial level in Alberta are also significant, as shown in Table 14. Average annual GDP growth for Alberta from 2020 to 2050 is lower for the two shocked scenarios, by 4.6% (SS) and 2.4% (BSS), with 2050 GDP ultimately reduced by 3.5% (SS) and 1.8% (BSS). Investment is particularly strongly affected, with the Shocks Scenario reducing annual investment growth by an average of 53% relative to the flat-price case. Consumption and employment are least affected since most of Alberta's economy is not directly reliant on the oil and gas sector, and since the labour and capital shed by those sectors in down years can be absorbed in other sectors. Employment is actually slightly positive in the SS, pushed by a high positive price swing late in the period. Net exports are hurt most in the BSS (down over 10% in 2050) and have a harder time catching up even as the oil price in that scenario trends back upwards—this is a stock effect driven by declines in the early period.

**Table 14.** Change in macroeconomic indicators relative to USD 55/bbl flat (Alberta)

	Metric	Scenario	Relative to USD 55 Flat	
			% Change in average annual growth (2015–2050)	% Change in size at 2050
Components of GDP	Consumption	1. Shocks	⬇️ -0.04%	⬇️ -0.03%
		2. Bigger shocks	⬇️ -0.11%	⬇️ -0.08%
	Investment	1. Shocks	⬇️ -53.05%	⬇️ -19.10%
		2. Bigger shocks	⬇️ -8.25%	⬇️ -3.24%
	Net exports	1. Shocks	⬇️ -0.01%	⬇️ -0.01%
		2. Bigger shocks	⬇️ -5.23%	⬇️ -10.20%
	Total GDP	1. Shocks	⬇️ -4.63%	⬇️ -3.49%
		2. Bigger shocks	⬇️ -2.40%	⬇️ -1.82%
Employment	1. Shocks	⬇️ -0.22%	⬇️ -0.14%	
	2. Bigger shocks	⬇️ -0.22%	⬆️ 0.13%	

Source: Navius modelling.

Royalties from the oil sands are highly volatile and significantly lower in the two shocked scenarios, as shown in Table 15. Provincial tax revenue is somewhat unaffected, with small changes and variability in total revenue over the simulations. This is not the case for oil sands royalties, however, with a variation of 3 to 4 times the USD 55/bbl flat scenario throughout the simulation, ultimately culminating in a much lower cumulative royalty take by 2050: reductions of 70% (SS) and 58% (BSS). A few drivers are at work here, including a royalty regime that scales up and down with the oil price, bitumen production that is highly sensitive to the oil and price, and investment uncertainty.

**Table 15.** Change in Alberta taxes and royalties relative to USD 55/bbl flat

	Scenario	Index of variance*	Cumulative total by 2050
Provincial tax revenue	1. Shocks	0.94	-3%
	2. Bigger shocks	1.04	-3%
Royalties (only oil sands)	1. Shocks	2.95	-70%
	2. Bigger shocks	4.02	-58%

* Coefficient of variation, which is standard deviation divided by the mean. The index is the coefficient of variation for the scenario relative to the flat USD 55 scenario.

Source: Navius modelling.

4.3 Summary of the Modelling Analysis

Both of the scenarios modelled here show significant negative results for the Alberta economy. A price scenario that aligns with the long-term assumptions of BP, Shell, and Total and the climate-ambitious scenarios of agencies like the CER, the EIA, and the IEA delivers much less economically than the pre-pandemic CER reference case. Specifically, the low-oil-price scenario shaves 5.2% off the oil and gas sector's annual contribution to Alberta's GDP relative to our reference case, or an average of CAD 4.4 billion per year between now and 2050. Employment in oil and gas drops 4.5% per year, for an average of over 6,300 FTE jobs out to 2050. Investment drops 5.3%, or just over CAD 2 billion per year, and royalties drop by 34.7%, or an average of just under CAD 2 billion per year. It is worth noting that our "low-price" scenario is not particularly pessimistic.

Much more striking is the result of modelling oil price volatility—dropping the common assumption of a smooth oil price trajectory out to 2050. The average price out to 2050 was the same for both shocked scenarios and the reference case. But in the shocked scenarios, oil and gas sector GDP contributions in Alberta drop by an average of 21% (SS) and 19% (BSS) per year (CAD 24.3 billion and CAD 21.8 billion) out to 2050. Sectoral output drops by 20% (SS) and 17% (BSS) over the time period, with negative impacts on employment—an average drop of 24,300 (SS) and 21,800 (BSS) FTE jobs annually. Royalties are particularly strongly affected, with drops of 43% (SS) and 41% (BSS). Investment sees an average annual drop of 30% (SS) and 26% (BSS) (CAD 11.2 billion or CAD 9.6 billion) compared to the reference case. For Alberta as a whole, average annual GDP growth from 2020 to 2050 is lower for the two shocked scenarios by 4.6% (SS) and 2.4% (BSS), with 2050 GDP ultimately reduced by 3.5% (SS) and 1.8% (BSS). Alberta-wide investment is particularly strongly affected, with the SS reducing annual investment growth by an average of 53% relative to the reference case.



These are significant impacts, and they derive from a reality that everyone concedes: future oil prices are going to be cyclical, as they have been historically. In fact, if anything, we can expect more volatility in the future, whether as a result of the increasing trend in climate-related disasters (United Nations Office for Disaster Risk Reduction, 2020), because of future pandemic events (Murdoch, 2020), or because of the volatility inherent in a declining market (see Section 3.6). Moreover, these impacts are only the result of dropping a smooth oil price assumption. Assuming both lower-than-expected prices and volatility together would yield more significant impacts.

The key questions stemming from this analysis are thus: how likely is the low-price scenario we modelled, and how volatile can we expect oil prices to be in future? If our assumptions are close to reality, then the oil sector in Alberta is not likely to drive prosperity in the coming decades in the way it has done for the last 30 years.



5.0 Synthesis: A view of the future

When considered together, the modelling above and the survey of determinants on which it builds help to coalesce a vision of the future of Alberta's oil sector.

The uptake of EVs is the most significant near-term influence on oil demand. Cost reductions and improvements in range, charging time, and infrastructure will all lead to a disruptive shift in consumer preferences; it will not be a gradual transition, but rather, an S-curve adoption. The shift will be accelerated by incentives, mandates, and infrastructure investment from climate-ambitious governments such as the United States. For the increasing number of net-zero target-setters, electrifying road transport is low-hanging fruit: a cost-effective, relatively painless way to drive emission reductions, often with a politically appealing industrial policy link. That shift will also be hastened by rapid uptake in fleet owners and ride-hailing operators who are conscious of lifetime cost savings. With road transport being 44% of global demand for oil, this is a significant transition.

There will be increases in demand for plastics and other petrochemicals, mostly driven by population and GDP increases in developing economies, and this will increase demand for oil. But it will not outweigh the EV effect. Even the IEA's unambitious Stated Policies Scenario sees petrochemicals increasing demand for oil by only 4.5 million bpd by 2040—less than 5% of current global production. A 10% reduction in oil demand for road transport would cancel this out. The anti-plastics movement is a wildcard and may only really bite if it finds traction in emerging economies.

Increasingly stringent fuel economy standards for the remaining conventional cars on the road will add to downward demand pressure for oil. In the medium term, the decarbonization of commercial transport—trucking, shipping, and aviation, which account for 12% of global oil demand—will also be significant, but the latter two are not yet near technological maturity.

There is no disagreement on the factors leading to peak oil demand; the only disagreement is on timing. Some argue that peak demand has already arrived. BP, Shell, and Total all forecast oil prices as steady or declining as of 2030—a prediction that is echoed by the IEA's Sustainable Development Scenario and the Canada Energy Regulator's Evolving Scenario, both of which are premised on the adoption of ambitious climate policies. Most analysts expect upfront cost parity between EVs and conventional cars as of the early- to mid-2020s (EVs are already cheaper on a lifetime basis). All this means that if we have not already hit peak oil demand, we are likely to do so by 2030.

Whenever that does happen—when we enter a period of secular decline in oil demand—everything will change. We may see unprecedented strategic behaviour among the world's oil producers, who have only before faced cyclical price shocks, always with the prospect of a return to growth. The strains on OPEC+ discipline will be intense, as oil-dependent states discount the value of future reserves and are tempted to race to sell the last barrel. If that discipline breaks, we



may see more price volatility than the historical norm, and the dominant players—Saudi Arabia and Russia—may even exploit volatility in a strategic attempt to permanently run high-cost producers out of the market.

In the post-peak world of low and declining prices, we will see continued production from existing Canadian oil sands mining operations, which have low operating costs and can sustain low prices, particularly if their capital investment is paid off. In the next decade, we will also see final investment decisions on expansion projects for SAGD operations, those having breakeven costs of less than USD 25/bbl at the field gate. But investment in big, new mining operations probably will not materialize, and it is likely that only the cheapest SAGD and tight oil projects will be able to come on stream.

Post-peak, new investment for the oil sands will be increasingly challenging. With markets concerned about long-term oil price outlooks, relatively short-lived investments in tight oil may get preference, and there will be pressure from shareholders to prioritize profits ahead of growth. Investment will also be significantly dampened by cyclical swings in oil prices, which may become more pronounced than the historical norm. Financing has been made tougher by the SCC's Redwater decision and by a growing movement to divest from fossil fuels. As a relatively GHG-intensive oil source, the oil sands will be increasingly targeted by the latter. Even an expected 20% reduction in upstream GHG intensity over the next decade will leave Canadian oil sands producers well behind their global competitors—30% more GHG intense than a weighted U.S. average and double that of Saudi Arabia. Moreover, this all assumes that those competitors will make no reductions of their own—an unlikely scenario, given that close to half of global methane reduction potential has zero net cost.

Oil will still be an important part of the Alberta economy in the run-up to peak demand, and even after. And, as noted below, the sector may find markets for bitumen beyond combustion. But as a conventional supplier, it will not be a strong source of new investment or growth. As such, while Alberta's oil sector may produce some profits and contribute royalties to the province over the next 20 years, it will not be a major employer, either in terms of direct employment or in terms of indirect jobs in support services or manufacturing—sectors that depend strongly on growth. This reality will be accentuated by the existing trend in the oil sector to replace labour by using technologies such as automation and artificial intelligence.



6.0 Conclusions and Recommendations

The starting point for this analysis was the question: in the decades to come, will Alberta's oil sector be able to drive economic prosperity the way it has in decades past? The answers are fundamentally important to the future prosperity of Alberta and Canada. They affect the workers and communities that depend directly and indirectly on the oil sector. They affect investors and a broad range of firms with a stake in the oil sector. And they affect federal and provincial policy-makers, who are charged with deciding where to focus government's priorities and support to ensure the long-term well-being of Canadians.

In the future described above, the oil sector will continue to be a major part of Alberta's economy for years to come, but—at least, as a producer of combustible hydrocarbons—it has poor long-term prospects. Its ability to contribute to Alberta's economy through growth and investment looks tenuous past the end of this decade. That conclusion leads directly to four policy recommendations.

OIL FOR COMBUSTION IS NOT AN APPROPRIATE TARGET OF INDUSTRIAL POLICY SUPPORT.

The levels of support detailed in Section 2.3 may be appropriate for sectors with high growth prospects, and even then, only where there is some market failure that public support can address. But they are not appropriate for mature sectors with poor long-term prospects. The first rule of 21st-century industrial policy is to apply support only to new activities, “to diversify the economy and generate new areas of comparative advantage” (Rodrik, 2004). That is not to say that mature sectors should get no support. But for policy-makers with an industrial policy lens thinking about where to allocate government support to maximize future prosperity, the oil sector as a producer of combustible hydrocarbons should be nowhere near the top of the list.

DIVERSIFICATION IS IMPERATIVE; START YESTERDAY.

Alberta has been striving for diversification arguably since the days of Peter Lougheed, with several high-profile roadmaps produced in the last 10 years (Energy Diversification Advisory Committee, 2018; Premier's Council for Economic Strategy, 2011). If it were a simple prospect, it would be well advanced by now. But two things bear highlighting. First, the support for diversification has been tepid compared to what has been invested in conventional industries like the oil sector. A single oil sector support measure—Alberta's CAD 1.1 billion equity infusion into Keystone XL—could have doubled the province's contribution to Alberta Innovates (Alberta's premier centre on innovation for diversification) for 5 years. Other Albertan leaders in the field of diversification—Canada's Oilsands Innovation Alliance and the Energy Futures Lab—are doing excellent work but could do much more if properly resourced. Second, the potential has never been more palpable, with opportunities built on the same resources that power the oil sector. This is in line with the principle that diversification must build on existing strengths and resources (Hausmann & Klinger, 2007). Examples include:



- Alberta Innovates has been working for years to help commercialize carbon fibre production from bitumen (Alberta Innovates, 2020; Stantec, 2018). A moonshot effort to commercialize that technology might have payoffs similar to another major (CAD 1.4 billion) Alberta technology push: AOSTRA’s work on SAGD, the innovation that made the oil sands viable (Hastings-Simon, 2019).
- Alberta Innovates has also worked on technology to make asphalt (derived from bitumen) more transportable, which would open up opportunities for Alberta as an exporter (Stantec, 2018).
- Geothermal energy is an obvious fit with existing resources and skills, possibly even using existing infrastructure such as abandoned wells (Leitch & Switzer, 2017).
- Production of lithium—in high demand as a component material for a range of “green” battery applications—might also use existing infrastructure, filtering lithium from oil well waste brine (Rieger, 2020).
- The production of so-called “blue” hydrogen—produced from methane but using carbon capture and storage—also builds on existing strengths (Transition Accelerator, 2020). The same goes for start-up innovators pursuing novel low-carbon hydrogen production methods (Orland, 2020).
- Home-grown innovations in methane emission detection (Tullis, 2020) and well abandonment processes and technologies have the double win of fostering exportable commercial innovation and dealing with the oil and gas sector’s environmental challenges.

These prospects may seem like poor replacements for a sector that has delivered monumental profits in Alberta over the last three decades; none are currently placed to match that level of economic clout. But that is simply an argument for urgency. The oil sands’ monumental profits were the result of a push for diversification away from conventional production that started in the 1970s. Diversification needs opportunity, will, expertise, and money, but it also needs time.

THE TRANSITION NEEDS TO BE ANTICIPATED AND MANAGED.

Transitions are never painless, but experience shows that they can be managed more or less successfully if they are anticipated (Stanford, 2021). The social and economic damage wrought in oil-dependent communities by the COVID-19 crisis offers powerful analogies to an unplanned transition. Closer to home, the death spiral of the coal industry in the United States, going on for over a decade but now accelerating toward the end game, provides terrible lessons on the impacts of denying the advent of transition for workers and communities (Carley et al., 2018). A recent Canadian analysis of employment transition from fossil fuel dependence concludes: “When workers are supported with generous income supports and adjustment assistance (including retirement incentives), and when strong commitments are made to alternative employment creation (including but not limited to jobs in renewable energy projects), these transitions can occur without involuntary layoffs or severe disruption to communities” (Stanford, 2021). This is more true in Canada than in almost any other oil-producing nation, given our relative lack of national dependency on oil and our high capacity to fund transitions (Stockholm Environment



Institute et al., 2020). Canada can draw on the successful process of planning and consultation in the coal power sector: the Task Force on Just and Fair Transition for Canadian Coal Power Workers and Communities (Task Force on Just Transition, 2018).

THERE'S NO TIME TO LOSE.

Successful cases of transition and diversification take decades to bear full fruit (Esanov, 2012; Subramanian, 2001). If our conclusions are accurate, there is no time to lose in assisting workers and communities in the move toward transition and in greatly raising the profile and urgency of efforts to foster diversification in Alberta. None of the necessary actions will happen in the shadow of an oil sector that continues to dominate the spotlight of public policy attention.



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