

The Transition
Accelerator



L'Accélérateur
de transition

Canada's Opportunity Playbook:
Pathways to Strategic Decarbonization

ENERGY CARRIERS

Oil and Gas



7.4 OIL AND GAS

Function	Fuels for transportation, power generation, space heating, industrial processes, and feedstock for multiple industries including chemicals and fertilizers.
GHG emissions	190–200 Mt CO ₂ e annually, representing about 28–31% of Canada's emissions (208 Mt or 30% in 2024).[74]* Emissions from the sector have increased over recent decades, driven by production growth, and are concentrated in upstream production and processing.
Options for decarbonization	Decarbonization Pathways: Methane abatement, electrification of upstream operations. Niche Pathways: Carbon Capture and Storage, blue hydrogen. Enabling Pathways: on-site clean power, lithium extraction from oilfield brines, geothermal power. Reduce production-related emissions to the lowest level possible through methane abatement, carbon capture, and efficiency improvements.
Stage of transition	Emerging: Blue hydrogen, lithium extraction from oilfield brines, geothermal power Diffusion: Methane abatement, electrification of upstream operations, carbon capture and storage, on-site clean power
Nature of the problem today	Emissions and emission intensity are high, and long-lived infrastructure and capital stock create transition complexity. Policy signals on decarbonization have strengthened since 2021 but remain subject to political uncertainty.
Other systemic issues	Deep economic dependence on oil and gas revenues in producing regions; environmental liabilities including abandoned wells and tailings ponds.
Opportunities and concerns	Leverage existing labour skills, industrial expertise, and infrastructure to support energy transitions; develop and export emissions-reducing technologies; avoid stranding assets prematurely through a managed and predictable transition.
Priorities for action	Reduce production emissions through methane abatement, efficiency improvements, and electrification of upstream operations. Strengthen industrial carbon pricing to provide a durable signal for carbon capture utilization and storage and other longer-term abatement investments.
Longer-term issues	Managing demand decline and macroeconomic impacts as electrification accelerates domestically and globally; reclamation liabilities; workforce and community transition in producing regions.
Indicators of progress	Sector production emissions and emissions intensity; upstream methane emissions.

* All noted references can be found in the full Playbook document.

7.4.1 Current Status

Canada's oil and gas sector is one of the country's most significant industries. Canada is the world's fourth-largest oil producer and fifth-largest natural gas producer. The sector directly contributed roughly 6% of national GDP in 2024, and supports approximately 200,000 direct jobs, with considerably more employment across supply chains and service industries.[154] In 2024, 93% of Canadian crude oil exports were directed to the United States, down from 97% the previous year due to the completion of the Trans Mountain Expansion Project.[183] The sector's economic weight is particularly concentrated in Alberta, Saskatchewan, British Columbia, and Newfoundland and Labrador, where it shapes provincial fiscal positions, investment patterns, and community livelihoods.

Since the 2021 edition of this report, the sector's operating context has shifted considerably. The collapse in global demand through 2020 and early 2021 caused widespread financial losses, asset write-downs, and accelerated consolidation across the industry.[184] Conditions reversed sharply with the post-pandemic recovery and the energy price shock following foreign conflicts, and Canadian producers recorded operating profits of \$66.6 billion in 2022.[185] Prices and

margins have since moderated from those highs, though oil sands production has continued to grow, supported in part by the Trans Mountain pipeline expansion. At the same time, global energy markets are being reshaped by accelerating electrification, tightening environmental standards in importing countries, and intensifying geopolitical competition over energy supply chains. The policy landscape in Canada has also evolved, with strengthened methane regulations, investment tax credits for carbon capture and clean hydrogen production and the introduction and subsequent withdrawal of a proposed federal oil and gas emissions cap in favour of a negotiated carbon pricing framework.

These developments underscore a fundamental reality: the oil and gas sector will continue to generate revenue and employment for Canada in the coming years, but the terms on which it does so are changing. How Canada manages this transition, which involves reducing production emissions, positioning for evolving global markets, and rolling out end-use alternatives (such as electric vehicles and heat pumps) that will ultimately reshape demand, will have significant consequences for national prosperity and regional economic stability.



7.4.2 Nature of the Problem

The oil and gas sector is Canada's largest source of greenhouse gas emissions. According to the most recent national inventory data, the sector accounted for approximately 208 Mt CO₂e in 2024, representing roughly 30% of Canada's total emissions.[61,186] Within the sector, oil sands production is the dominant source (approximately 44% of sector emissions), followed by natural gas production and processing, conventional oil production, and petroleum refining.[61,187]¹ Production growth has been the primary driver of emissions increases: total crude oil output has roughly tripled since 1990, with oil sands production increasing more than eightfold over that period.[187]²

Of course, production-related emissions represent only a fraction of the total climate impact of oil and gas. When the end-use combustion of oil and gas products is included (in vehicles, furnaces, industrial equipment, and power generation), the full lifecycle emissions are roughly five times greater than production emissions alone.[188]

In a net-zero framework, this distinction matters. Reducing production emissions is necessary, but the larger prize, in emissions terms, lies in displacing the end-use combustion of fossil fuels through electrification and the deployment of alternative energy carriers. This is the central argument of this report: the most effective long-term strategy for reducing the emissions associated with oil and gas is to electrify demand.

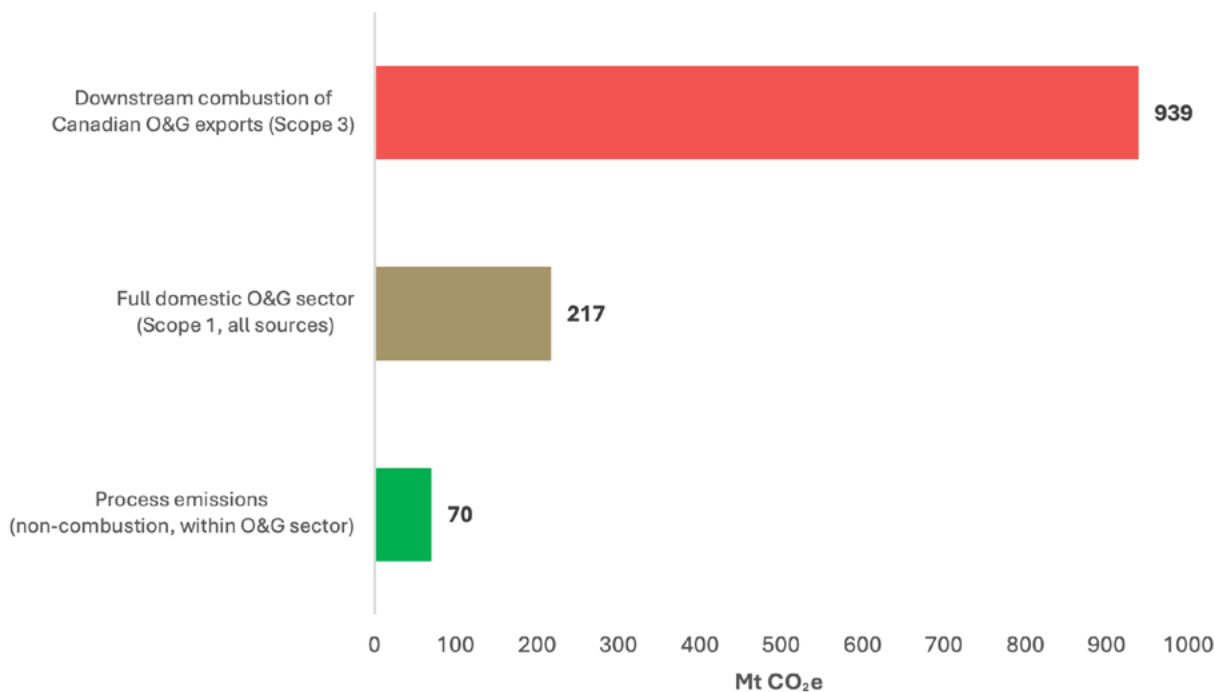


Figure 21. 2022 Process vs. Downstream Combustion (Mt CO₂e)

Source(s): Environment and Climate Change Canada, *Greenhouse Gas Sources and Sinks in Canada: Executive Summary 2026 (2025)*[46]. *Climate Action Tracker, Canada's Uncounted Emissions (2024)*.^[189] International Energy Agency, *Energy Balance (2024)*.^[190]

¹ ECCC, 2024 National Inventory Report (data for 2022). Oil sands: 87 Mt (40%); natural gas production and processing: 54.5 Mt; conventional oil: 39 Mt; petroleum refining: 17 Mt.

² From 1990 to 2022, total crude oil production increased by 193%.

The scale of those downstream combustion emissions also reflects a structural feature of Canada's export position. The vast majority of Canadian crude oil exports flow to the United States, and the bulk of production- and transmission-related emissions from the sector are tied to supplying that single market. The United States is itself on an electrification trajectory, likely slower than Canada's, but directionally the same.[191] As U.S. end-use demand for oil and gas gradually contracts, Canadian producers will face pressure to redirect volumes. The obvious alternative is Asian markets, and Canada is positioning itself as a stable and reliable supplier to the Indo-Pacific. But those markets are simultaneously pursuing strategies to reduce their own hydrocarbon dependence, driven not primarily by climate policy but by energy security concerns: a lesson reinforced by recurring supply disruptions, price volatility, and the 2026 closure of the Strait of Hormuz.[192] The practical implication is that the long-run market environment for Canadian oil and gas is structurally more constrained and more competitive than near-term prices suggest, and that this dynamic compounds the challenge of justifying long-lived capital investment in conventional production.

Beyond greenhouse gas emissions, the sector carries significant environmental liabilities. These include multi-billion-dollar reclamation obligations from inactive and orphaned wells, unfunded liabilities associated with oil sands tailings ponds, and widespread landscape fragmentation.[193] These obligations represent fiscal and environmental risks that grow with the continued expansion of conventional operations and require proactive management regardless of the pace of the energy transition. In this sense, they are not simply legacy issues; ensuring adequate financial provisioning for these liabilities and not deferring costs to future taxpayers is a governance issue that grows more urgent with time.

The transition challenge is not only environmental or technological, but also economic and institutional. The most significant obstacle to the sector's transition is the gap between the long-term direction of the global energy system and the near-term economic incentives facing producers. Oil and gas remain highly profitable, and current commodity prices reward continued production expansion. In this context, investment in deep decarbonization competes directly with returns from conventional operations. While record profitability provides the financial capacity to invest in transition, the commercial pressure to deploy capital toward production growth is strong.

Infrastructure lock-in compounds this dynamic. Canada's oil and gas asset base (wells, pipelines, upgraders, processing plants) was built for a fossil-fuel economy and represents hundreds of billions of dollars in sunk capital. Retrofitting or repurposing this infrastructure for lower-emission operations requires significant additional investment, and in some cases is technically infeasible. Continued investment in conventional long-lived assets further strengthens this lock-in and raises the risk of future stranded assets.

Policy signals have become more directional, and federal-provincial friction has eased since the November 2025 Canada-Alberta MOU and its May 2026 Implementation Agreement, which replaced the contested emissions cap with a negotiated carbon pricing framework and streamlined project assessment processes. Whether these commitments prove durable remains to be seen, and international factors — including the evolving U.S. regulatory and trade landscape — add further uncertainty for long-term capital allocation decisions.

The political difficulty of imposing greater stringency on production emissions is real, but it will diminish as international markets increasingly differentiate on emissions

intensity. As carbon border mechanisms and importer standards take hold, the market case for low-intensity production aligns with the regulatory case. Over time, this could shift the balance of leverage between governments and industry, making stronger production-side requirements more politically and economically defensible.

In the long term, global demand for oil and gas is projected to plateau and eventually decline as electrification advances across major economies, though the pace and timing continue to be uncertain and are subject to geopolitical, technological, and policy variables. How quickly this demand contraction reaches Canadian producers will be shaped by the competitiveness of Canadian production, the success of carbon border mechanisms in importing countries, and the availability of lower-cost alternatives. This creates a difficult planning environment, whereby near-term market conditions still support expansion, even as the longer-term direction of travel points toward a more competitive and constrained market.

So long as domestic and international demand for oil and gas products remains robust, the economic case for supply-side transformation is harder to make. This reinforces the strategic priority of accelerating demand-side electrification while preparing for a more uncertain long-term market environment.

7.4.3 Net-Zero Pathways

In a net-zero world, fossil fuels will still have a role, but a significantly diminished and different one. Residual uses may include feedstock for petrochemicals, liquid fuels for aviation, specialty products such as lubricants, asphalt, and waxes that lack near-term substitutes, and fuel supply for remote and off-grid communities where infrastructure alternatives are uneconomical.

Beyond these residual uses, it is worth noting that even absent a global policy commitment to net zero, structural pressures on fossil fuel demand are already intensifying. The world's largest energy-importing regions—Europe and Asia—have powerful and durable incentives to electrify and reduce their dependence on imported hydrocarbons. Those incentives are not primarily climate-driven: they are strategic. Recurring supply disruptions, price volatility, and the concentration of critical transit routes in geopolitically unstable regions have consistently demonstrated the systemic vulnerabilities of fossil fuel import dependence. The 2026 closure of the Strait of Hormuz, which the IEA described as the largest oil supply disruption in the history of the global oil market, is only the most recent, and most dramatic, illustration of this dynamic.[194] For major importers, the energy security case for electrification is increasingly entangled with the climate case, and both are pointing in the same direction.

These pressures reinforce a central conclusion of this report: the trajectory of Canada's oil and gas sector toward net zero involves action on two distinct fronts: reducing emissions from production operations and managing the structural decline in fossil fuel demand as end-use sectors electrify. The following pathways describe the principal options available to the sector. They are not mutually exclusive; a realistic trajectory will combine elements of each, with the balance shifting over time as technologies mature and markets evolve.

Reduce production emissions while continuing to produce oil and gas.

This pathway focuses on driving production-related emissions toward the lowest achievable levels through a suite of technologies: methane abatement (leak detection and repair, elimination of routine venting and flaring), electrification of

upstream operations, carbon capture and storage at major facilities, process efficiency improvements, and the use of lower-emission extraction technologies. This is the pathway most directly aligned with the current industry trajectory, and it has received significant policy and investment attention.

Canada has made measurable progress on this front. Methane emissions from the oil and gas sector fell approximately 40% between 2014 and 2023, even as production continued to grow.[195] The federal government finalized enhanced methane regulations in December 2025, targeting a 72% reduction from 2012 levels by 2030.[196]

These developments have unfolded alongside a broader federal-provincial realignment. The November 2025 Canada-Alberta Memorandum of Understanding set aside the proposed federal emissions cap in exchange for Alberta's commitment to strengthen industrial carbon pricing and advance carbon capture investment. This led to an agreement-in-principle in March 2026 on methane equivalency,[197] an April Co-operation Agreement streamlining environmental and impact assessments for major projects,[198] and a May 2026 Implementation Agreement that formalized the MOU's commitments on carbon pricing and the Pathways CCS project.[199]

However, aside from methane abatement, the policy environment around decarbonizing production emissions is in flux. In late 2024, the Trudeau government published proposed regulations to cap upstream oil and gas emissions through a cap-and-trade system. [192] The proposal drew strong opposition from industry and producing provinces, and the November 2025 Canada-Alberta MOU effectively set it aside. The federal government agreed to forgo the cap in exchange for Alberta's commitment to

strengthen industrial carbon pricing and invest in carbon capture.[201]

With the emissions cap off the table, industrial carbon pricing is now the primary regulatory signal for decarbonization investment in the sector. But that signal is itself weakened. Alberta froze its Technology Innovation and Emissions Reduction (TIER) carbon price at \$95 per tonne in 2025,[202] and the market price collapsed to between \$17 and \$40 per tonne, due to a surplus of banked credits and weak demand.[203] The May 2026 Implementation Agreement attempts to address both problems, establishing a rising headline price schedule and a credit price floor reaching \$130 per tonne by 2040.[199], At these prices, there is little economic incentive for producers to invest in deep emissions reductions.

This matters directly for the viability of carbon capture at scale. The flagship initiative, the Pathways Project, a proposed \$16.5 billion CO₂ pipeline and storage hub in northern Alberta backed by the five major oil sands producers now organized as the Oil Sands Alliance,[204] depends on robust carbon credit revenue to close its business case. The May 2026 Implementation Agreement commits both governments to completing a trilateral MOU with the Oil Sands Alliance and extends the Alberta Carbon Capture Incentive Program to support it.[199] The project also faces structural cost challenges: CCS in remote oil sands operations is expensive relative to other abatement options, and independent analyses have raised doubts about whether it can break even under current cost trajectories.[205] Even at full scale, the project would address only a portion of production emissions.

The economic logic of this approach is straightforward: as global markets increasingly differentiate between higher- and

lower-emission sources of energy, Canadian producers with lower production-emission profiles will be better positioned to retain market access and command premium pricing. The EU's incoming methane intensity standards for imported fuels, and similar signals from Asian importers, reinforce this competitive case.[206]

Nevertheless, this faces real constraints. Reducing production emissions to near zero is technically demanding and capital intensive, particularly for in-situ oil sands operations. It would raise production costs, reducing economic competitiveness. And while the carbon intensity of barrels could theoretically be a market differentiator, this signal has not yet materialized into a market advantage, making long-term decarbonization investments harder to secure absent strong regulatory signals.

Develop net-zero energy products and alternative uses for hydrocarbon resources.

Rather than producing oil and gas exclusively for combustion, some segments of the industry could shift toward net-zero energy carriers, principally hydrogen produced from natural gas with carbon capture (so-called blue hydrogen), or potentially electricity generated from natural gas with CCS. Alberta's geological advantages for carbon storage, existing pipeline infrastructure, and established gas processing expertise give the province a cost advantage in blue hydrogen production.

Interest in hydrogen as an energy carrier has grown substantially since 2021, driven by industrial decarbonization needs in sectors like steel, cement, and heavy transport, as well as by emerging export opportunities. Canada's federal hydrogen strategy and provincial strategies in Alberta and British Columbia have established frameworks for development.[207] However, low-carbon hydrogen production at

scale remains in early stages, and the business case depends on sustained demand growth, infrastructure buildout, and continued cost reductions. More details about hydrogen's role in a net-zero energy system are available in the hydrogen section of this report.

Beyond energy carriers, hydrocarbon resources can serve as feedstock for non-combustion products: petrochemicals, carbon fibre, activated carbon, and other advanced materials. Bitumen-beyond-combustion concepts such as these have received research attention in Canada.[207] These applications could generate value from hydrocarbon resources without the associated combustion emissions, though most are at early commercial stages and none would match the economic scale of existing oil and gas operations.

Diversify into adjacent energy and resource sectors.

Some oil and gas companies are already diversifying into adjacent areas, such as renewable electricity generation, geothermal energy, critical minerals, and carbon management services. Lithium extraction from oilfield brines is being actively explored in Western Canada.[208] Alberta and Saskatchewan have significant solar and wind resources. CCUS is itself becoming a commercial service industry, with the sector's geological and engineering capabilities directly transferable.

Geothermal energy serves as an interesting example to repurpose existing expertise to support renewable energy development since it can leverage subsurface expertise, drilling technologies, and geological data from the oil and gas sector.[209,210] Emerging advanced geothermal systems including closed-loop technologies developed by Calgary-based Eavor, which require no fracking or water and can be deployed across a much wider range of geological settings than conventional

geothermal, are drawing international interest. [211] Canada's first co-produced geothermal power plant is already operating at Swan Hills, Alberta, using legacy oil and gas well infrastructure.[212] Alberta established a formal regulatory framework for geothermal development in 2022, including provisions for converting existing oil and gas wells to geothermal use.

This approach is best understood not as a direct replacement for oil and gas activity but as part of a portfolio strategy that builds resilience and captures emerging opportunities. Its relevance will grow as the energy transition progresses, global demand patterns shift, and new revenue streams mature.



Competitiveness Implications

Canada's methane abatement sector (over 130 firms, with a projected 34,000 jobs by 2040) is not simply a domestic compliance industry. It is an export capability being built under conditions few competing jurisdictions can match. Deploying across dispersed conventional wells, in-situ oil sands, offshore platforms, and northern gas processing facilities means these firms field-test their technologies under a wider range of operating conditions than any other major producing jurisdiction generates, a deployment credential with direct export value. The EU's methane regulation (2024/1787), which imposes intensity standards on imported energy, is the leading edge of an importer-side compliance market. The condition that sustains this capability is domestic regulatory consistency: Canada's own methane stringency maintains the commercial base these firms need to accumulate the operational track record that gives them their international edge. The risk is not that methane regulations cost too much; it is that inconsistency in the domestic regime erodes the proving ground before the export market fully materializes.

7.4.4 Priorities for Action

Focus on end-use electrification as the highest-impact use of limited government capital. As this report argues throughout, the most consequential reductions in emissions associated with oil and gas will come not from within the sector itself, but from displacing the combustion of fossil fuels in transportation, buildings, and industry. These end-use emissions represent roughly 80% of the lifecycle total.[213] Governments face real constraints on fiscal and political capital, and directing that capital toward grid buildout, EV adoption, heat pump deployment, and industrial electrification delivers the largest structural impact. As these transitions advance, they reduce domestic fossil fuel consumption and, over time, reshape global demand patterns, and provide a timeline for diversification strategies to develop.

Implement and maintain strong methane regulations. Methane abatement is the most cost-effective near-term emissions reduction available in the sector, with abatement costs estimated at \$48 per tonne CO_{2e} or less. Canada's enhanced methane regulations, finalized in December 2025, provide a clear framework, though a March 2026 Alberta-Ottawa agreement-in-principle on provincial implementation timelines has introduced some uncertainty of its consistent application.[197,214] Maintaining regulatory consistency and supporting the growth of Canada's methane abatement technology sector, which already includes over 130 firms and has the potential to create 34,000 jobs by 2040, strengthens both the climate and competitiveness case.[195]

Employ regulations and fiscal measures to encourage sector emission abatement through electrification, efficiency and CCUS approaches. If an industrial pricing regime is to be maintained, its architecture should be sufficiently robust to encourage incremental change from a business-as-usual scenario.

Support hydrogen development and net-zero fuels where the economics and demand warrant. Blue hydrogen production leverages Canada's natural gas resources, CCS expertise, and geological storage capacity. Federal and provincial hydrogen strategies should focus on building demand in hard-to-electrify sectors (e.g., industrial heat, heavy freight) and on the infrastructure needed to connect supply and demand.

Prepare for regional economic adjustment. As the energy transition progresses, producing regions will face adjustment pressures. Proactive investment in economic diversification, workforce development, and community transition planning done well in advance of acute economic disruption is essential. This includes supporting the development of new industries and value chains that can absorb the transferable skills concentrated in oil and gas regions, including engineering, project management, geosciences, and skilled trades. Because these capabilities and communities are geographically concentrated, transition planning must be place-based and proactive, rather than generic. It should be designed to ensure that producing regions participate in the economic upside of the energy transition rather than simply bearing its adjustment costs. This is both an economic and a political imperative.

Criteria Status

■ ■ ■ ■ ■ Fails to meet criteria ■ ■ ■ ■ ■ Meets in some respect
■ ■ ■ ■ ■ Not promising ■ ■ ■ ■ ■ Potentially meets criteria
■ ■ ■ ■ ■ Meets criteria

7.4.5 Oil and Gas Pathways Table

			ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION- MAKERS		ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA- STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Oil and Gas Production											
Methane Leak Abatement Detection and repair, vapour recovery, and elimination of routine venting and flaring	Decarbonization Pathway Cost-effective near-term lever. Central to Canada's climate and trade strategies. Requires carbon removals for net zero.	Deploy Sustain and enforce finalized regulations. Support scale-up of Canadian methane abatement service sector.	Targets one element of oil and gas production emissions. Reduces significant near-term GHG emissions. Would require complementary measures including carbon removals to get to net zero.	Low cost compared to other direct GHG management measures. Potential to recover saleable gas, partially offsetting costs.	Growing market for specialized oil and gas equipment. Canada has many technology firms and can export tech and expertise.	Many technologies mature and used across Canada.	Integrates with existing processes.	Relies entirely on existing upstream infrastructure. Well-established domestic supply chain of equipment manufacturers, service companies, and measurement technology providers.	Reduces pollution. Broadly accepted.	Relevant to governments and producers as frequently lowest cost abatement option.	Can improve air quality around operations.
Carbon Capture and Storage (CCS)	Niche Pathway Effective where CO ₂ streams are concentrated and storage geology is favourable. Not a system-wide solution for all sector emissions.	Enable Support deployment at suitable point sources where pricing, geology, and hub infrastructure align. Develop policy to stimulate investment.	Can eliminate meaningful share of emissions from specific facilities. Does not address very dilute upstream sources or end-use combustion. Will require additional removals.	Adds operating cost without revenue generation. Requires strong policy signals.	Potential for CCS expertise as an export.	Mature for some applications. Used internationally and in Alberta.	Retrofits feasible at large point sources. More complex at distributed upstream facilities.	Requires CO₂ pipelines and storage hubs. Alberta geology is well-characterized but transport network is limited.	Public concern around long-term leakage and liability. Mixed Indigenous perspective.	Strong industry interest. Weak regulatory signals.	Co-benefits through CO₂ feedstock for industrial uses. Continued environmental concerns from oil and gas production.

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Electrification of upstream operations electric drives, grid-tied facilities, co-gen displacement, vehicle fleet and equipment electrification	Decarbonization Pathway Essential to decarbonizing the energy used in oil and gas production. Requires decarbonized electricity.	Deploy Prioritize transmission build-out into oil sands basins. Requires supportive policy environment.	 Can decarbonize many upstream operations, equipment and process heat, but dependent on decarbonized electricity.	 Economics currently challenged and would require significant policy intervention.	 Stimulates demand for clean power, transmission, and electrical trades. Retains regional employment.	 Deployed at Canadian sites, including some oil sands in-situ operations.	 Requires facility redesign and reliable grid access or substantial decarbonized on-site generation.	 Requires significant transmission build-out and generation capacity additions.	 Generally supported. Transmission corridor siting can attract opposition.	 Limited stakeholder engagement.	 Reduces local air pollution and noise. Risk of stranding existing assets.
Hydrogen Fuel Switching Cogeneration and gas turbines, process boilers, compression drives, vehicles and equipment	Potential Niche Pathway Viable decarbonization lever for combustion assets where electrification is difficult. Dependent on low-carbon hydrogen supply.	Enable Advance where low-carbon hydrogen supply is credible and off-take is firm. Prioritize turbine hydrogen-readiness in new cogeneration builds.	 Can achieve significant CO ₂ reductions. Net zero only achievable with near-zero upstream methane leakage and high-capture rate CCS and removals.	 Economics currently challenged and would require significant policy intervention.	 Leverages Alberta's existing gas processing expertise and CCS-ready geology for hydrogen production.	 Maturity varies by technology.	 Existing cogeneration units can blend hydrogen. Sole use of hydrogen will require substantial upgrades or equipment replacement and NOx control systems.	 No dedicated hydrogen supply infrastructure exists at O&G production sites. Requires new production facilities, compression, pipelines or on-site storage.	 Safety concerns around hydrogen flammability and storage.	 Alignment with government hydrogen strategies. Active investment by some producers and OEMs in hydrogen-ready turbine upgrades.	 Repurposes sector expertise. Produces NOx emissions but better overall air quality.
Low-Energy Extraction Technologies Solvent-assisted steam-assisted gravity drainage (SAGD), radio-frequency and electro-magnetic heating	Potential Enabling Pathway Could be part of a net-zero system provided decarbonized production. May reduce the energy intensity — and potentially emissions — of in-situ oil sands extraction.	Incubate Support R&D, field pilots, and transparent reporting of real-world performance data before commercial scaling.	 Reduces energy intensity and associated emission but does not eliminate emissions. Requires decarbonized production.	 Potential operational cost savings from lower steam and energy use. High capital costs.	 Canadian-led R&D ecosystem with IP and service industry potential.	 Pre-commercial. A few pilots and demonstrations exist with limited long-term field data.	 Can retrofit some SAGD assets. Requires process changes and operator training.	 Largely uses existing oil sands infrastructure and well pads.	 Mixed perception. Performance claims are held primarily by industry. Limited independent verification.	 Relevant to government and academia with pilots. Important to industry if cost savings occur.	 Energy and water savings. Reduced steam-to-oil ratio. Land-use impacts persist.

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
On-Site Clean Power Generation (Small modular reactors, solar and wind)	Enabling Pathway Provides low-carbon electricity and/or heat directly to remote upstream facilities where grid access is absent or unreliable. Enables electrification of operations.	Incubate Avoid scaling investment ahead of proven economics. With improvement continue R&D and pilot funding for SMRs and electrothermal storage. Advance regulatory frameworks for nuclear deployment in Alberta.	 Can fully decarbonize on-site power and heat when powered by zero-emission sources.	 Solar and wind cost-competitive in some contexts but intermittency requires storage investment. Small modular reactors uneconomic for oil sands applications under current conditions.	 Small modular reactor development would leverage Alberta's engineering and supply chain base and create high-skilled jobs.	 Solar and wind mature but limited application in remote northern sites. Small modular reactors are not commercially available in Canada and are not proven at remote sites.	 Small modular reactors co-location with SAGD facilities creates new regulatory and safety challenges. Solar/wind requires storage and backup to match continuous 24/7 steam demand.	 No nuclear supply chain established for remote locations. SMR components require new manufacturing pathways. Renewable on-site power supply chains more developed.	 Public awareness of nuclear energy in Alberta is low. Opposition exists from communities near proposed sites and some Indigenous groups. Renewable opposition also exists.	 Alberta and federal governments actively exploring small modular reactors. Some interest from producers but economics are the limiting factor. Renewables have a low-level of interest.	 Improved air quality from zero-emission power generation. Potential to export power surplus to the grid. Timelines may create significant stranded asset risk if oil sands demand declines faster than anticipated.
Net-Zero Products from Hydrocarbon Resources											
Blue Hydrogen (Natural gas Reforming with CCS, methane pyrolysis, autothermal reformation with CCS)	Niche Pathway Leverages Canada's gas resources and geological storage to generate net-zero energy. Contingent on very low upstream methane leakage.	Enable Advance where end-use demand is firm. See hydrogen section for detail.	 Can approach net zero only at high capture rates and with near-zero upstream methane emissions. May require carbon removals for residual emissions.	 More cost-competitive than green hydrogen. Contingent on gas prices, capture costs, and durable policy signals.	 Leverages existing gas processing expertise and subsurface storage. Export potential through Western corridors.	 Steam methane reforming with CCS is commercial internationally. Other technologies are in demonstration and pre-commercial.	 Builds on existing gas-processing practices. Integrates with proposed CCS hubs.	 Requires hydrogen demand, new hydrogen distribution, storage, and CCS network build-out.	 Concerns of upstream methane leakage. Safety concerns related to hydrogen handling.	 Some investment by major producers. Interest from some provincial governments.	 Repositions gas assets for a decarbonized economy. Extends fossil fuel production.

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Electricity Production from Natural Gas with CCS	<i>Potential Niche Pathway</i> Can be used as a backup power source while renewables are built out or for marginal balancing in a net-zero system. Potential export opportunity.	Incubate Support R&D for carbon capture from existing natural gas assets. Watch for local or regional power reliability issues.	 Difficult to capture all emissions with CCS. Requires negative emissions, which can be limited, to offset lifecycle emissions.	 Costly due to CCS. Needs subsidies but may become moderately competitive for baseload power.	 Electricity export potential in limited regional circumstances.	 Demonstration stage. Technology for post-combustion capture from gas turbines is being tested.	 Best suited to baseload or steady-output roles, cycling and peaking operation reduces capture efficiency. Retrofitting existing plants is feasible but requires significant site engineering.	 Benefits from existing infrastructure but requires new CO ₂ pipelines and strong methane management.	 Opposition remains over continued fossil fuel reliance and CO ₂ storage concerns.	 Relevant to gas producers and suppliers, Alberta, and industries needing firm power.	 Offers reliable low-carbon power and aids grid stability. Air quality and health issues with conventional combustion.
Non-Combustion Uses for Bitumen (i.e. Carbon fibre, asphalt binder, energy storage devices)	<i>Potential Niche Pathway</i> Extracts value from bitumen, avoiding combustion emissions.	Incubate Continue targeted R&D and build market linkages into carbon-constrained value chains.	 Avoids combustion emissions from bitumen. Requires up-stream abatement of methane and CO ₂ . May require removals.	 Long-term outlook unclear and varies by product. Competition from cheaper feedstocks.	Diversification opportunity for Alberta. Demand for carbon materials is growing.	 Mostly laboratory and early pilot stage.	 Requires new processing facilities separate from conventional refining.	 Requires new supply chains, manufacturing capacity, and networks. Asphalt binder faces specific transportation difficulties.	 Concerns about tailings, land disturbance, and reclamation.	 Active government-funded ecosystem. Producers supportive as feedstock suppliers, end use commitments limited.	 New markets and reduced reliance on combustion revenue. Continued upstream environmental liabilities.

			ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS		ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
 Resource Diversification											
Lithium Extraction from Oilfield Brines (Direct Lithium Extraction)	Enabling Pathway Repurposes sector capital, infrastructure, and workforce to supply critical minerals for the broader energy transition. Does not directly reduce oil and gas emissions.	Incubate Support piloting, validation, and integration with existing oilfield infrastructure; align with federal and provincial critical minerals strategies.	 Supports the broader net-zero transition rather than abating sector emissions directly.	 High capital costs. Costs expected to fall as technology matures. Price exposed to global lithium markets.	 Diversification opportunity. Builds on subsurface and brine-handling expertise. Battery supply chain opportunities.	 Pilot and demonstration stage. Provincial projects advancing, but no commercial operations to date.	 Uses existing wells, brine handling, and operational know-how. Minimal disruption from operations.	 Leverages existing facilities and well pads. Downstream critical mineral supply chain is nascent in Alberta.	 No particular concerns.	 Strong alignment with federal critical minerals strategies. Active industry participation.	 Low land disturbance. Regional diversification. Workforce transition pathway for oilfield service firms.
Geothermal Power (Closed loop, Conventional, and Deep)	Enabling Pathway Geothermal has potential for generating net-zero electricity and heat. Can transition oil and gas expertise to a net-zero industry.	Enable Build up regulatory frameworks. Support transitioning expertise. Support closed loop R&D as well as pilot and demonstration projects.	 Conventional geothermal releases some carbon dioxide. Closed loop geothermal is more promising for net zero.	 Not cost-competitive in Canada due to high drilling and capital costs. Potentially viable in remote locations.	 Established Canadian leadership in advanced geothermal. Drilling and subsurface, expertise transferable from oil and gas. Strong technology export potential.	 Demonstration stage with one closed loop project under construction in Canada. Deep geothermal in early research. Conventional geothermal is mature.	 Drilling, subsurface knowledge, and brine management map directly from oil and gas operations. Alberta regulatory framework includes provisions for well conversion. Site-dependent and best suited to regions with accessible heat at depth.	 Can leverage oil & gas infrastructure and expertise with standard equipment and a ready supply chain. Closed-loop systems require specialized tools not yet in domestic supply chains.	 Significant concerns of seismic activity for conventional geothermal. Support from off-grid Indigenous communities with closed-loop systems.	 Western provinces, oilfield service firms, and federal innovation programs as a transition opportunity. Utilities are cautious. Active investment in Canadian technologies.	 Baseload zero-emissions power —addresses intermittency of other renewables. Low land and water footprint. Can affect water quality if conventional geothermal is used.