The Low-Carbon Playbook

Policies to foster Alberta's competitiveness in a decarbonizing world

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Table of Contents

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Clean Prosperity is a Canadian climate policy organization. We advocate for practical climate solutions that reduce emissions and grow the economy. Learn more at CleanProsperity.ca.

The Transition Accelerator is a pan-Canadian organization that works with others to identify and advance viable pathways to a net-zero, prosperous and competitive Canada in 2050. Learn more at TransitionAccelerator.ca.

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Abbreviations

Sections of the *United States Internal Revenue Code* on clean-energy tax credits

40B	Sustainable aviation fuel
45J	Advanced nuclear
45Q	Carbon capture and storage
45U	Zero-emission nuclear power
45V	Hydrogen
45Y	Clean electricity
45Z	Clean fuels

CCfD	Carbon contract for difference
CCUS	Carbon capture, utilization, and storage
DAC	Direct air capture
ERA	Emissions Reduction Alberta
ERED	Alberta Emissions Reduction and Energy Development Plan
HPB	High-performance benchmark
IRA	Inflation Reduction Act
ITC	Investment tax credit
PTC	Production tax credit
RINs	Renewable identification numbers
SAF	Sustainable aviation fuel
SMR	Small modular reactor
TIER	Technology Innovation and Emissions Reduction (Regulation)

Executive Summary

Alberta has everything a province needs to compete in a decarbonizing world — a strong industrial base, abundant energy and natural resources, a skilled workforce, reliable regulatory processes, and a large, active carbon market. But the *US Inflation Reduction Act* (IRA) has changed the stakes. Without a comprehensive strategy to compete in a world on its way to net-zero emissions, Alberta risks missing out on massive economic opportunities.

This working paper looks at structural challenges facing Alberta in the new race for low-carbon investment, extending previous work by the authors on challenges facing Canada as a whole. We analyze the incentives for nine low-carbon technologies across three broad sectors: low-carbon fuels, carbon management, and electricity. Our focus is "bankable incentives" that provide upfront certainty to project developers and investors.

For several technologies, we find that the IRA has created "bankable gaps" between investment incentives for low-carbon projects in the US and Alberta. For example: a blue ammonia producer in Alberta is eligible for Canada's new federal investment tax credits (ITCs) for carbon capture and hydrogen, as well as the Alberta Petrochemicals Incentive Program. Our analysis finds these incentives are worth $0.09[1] per kilogram of blue ammonia produced. In contrast, this same project sited in Texas could generate $0.20/kg under the IRA's 45V production tax credit (PTC). This bankable gap of $0.11/kg means that an industrial-scale blue ammonia producer could be leaving over 100 million dollars on the table by siting in Alberta rather than Texas.

Alberta's ambitions to become a more competitive and diversified energy powerhouse are undermined by bankable gaps like this. To compete, the province must pursue new policies that can systematically bolster investment in emerging low-carbon industries. The longer bankable gaps remain, the greater the risk that Alberta falls behind competing jurisdictions in the race for both technology and talent.

Fortunately, Alberta has policy levers that could quickly close these bankable gaps and become a stronger destination of choice for low-carbon investment — most importantly through its Technology Innovation and Emissions Reduction (TIER) Regulation.

Based on our findings, we recommend the Alberta government take three key actions:

1 All currency amounts in this working paper are in Canadian dollars unless otherwise specified.

1. Make TIER a bankable asset for more low-carbon projects.

Revenue from carbon credits can help support the business case for any new low-carbon project at a TIER-eligible facility. However, Clean Prosperity's modelling shows a risk of oversupply of TIER credits in the coming years, which would lead to depressed credit prices. Lack of certainty about the future value of TIER credits is holding up final investment decisions on numerous shovel-ready projects.

Financial instruments called **carbon contracts for difference (CCfDs)** offer a solution, acting as insurance on the future value of carbon credits.[2] CCfDs could fully close the incentive gap for a number of project types. **Implemented correctly, CCfDs are low-cost, present minimal financial risk to the government, and can even offer financial upside. Without CCfDs, alternative measures to make Alberta a competitive destination for investment could cost billions of dollars.**

The federal government announced intentions to consult on a broad-based program of CCfDs in the 2023 federal budget, though no formal consultation process has begun.

Alberta stands to benefit tremendously from CCfDs. The province should take immediate steps to ensure their successful implementation, and complement the program with additional actions that can further reduce investor uncertainty:

A. Bring CCfDs to the TIER market — either by actively partnering on a federal program, creating a made-in-Alberta version, or a combination of both. Alberta should advocate for the importance of the federal CCfD program to Alberta's economy, be a constructive partner in consultations, and explore options for a provincial CCfD program in parallel.

B. Publish average prices for credits traded under TIER to improve overall market transparency and as a prerequisite to a broad-based CCfD program.

C. Design new high-performance benchmarks in TIER for emerging sectors. These benchmarks would provide greater clarity for new projects about both the price and volume of TIER credits that projects could expect to generate, helping to crowd in first-of-kind investments.

D. Define the carbon-price path for TIER beyond 2030, building on the strong price path established in Alberta's Emissions Reduction and Energy Development (ERED) Plan. This will give firms and investors further confidence in the long-term viability of their projects.

2 See the Conclusion section for an explanation of CCfDs.

2. Apply 100% of present and future TIER revenues to support further decarbonization.

Currently, a portion of TIER revenues are diverted to the province's General Revenue Fund to assist with deficit reduction. This arrangement should be reconsidered in light of Alberta's strengthened fiscal position.

Earmarking 100% of TIER revenues in support of industrial decarbonization is a straightforward option to accelerate low-carbon growth. Complemented with a modern industrial strategy, this change would help maximize TIER's ability to drive new investments.

Committing to reforming the TIER Fund in the 2024 provincial budget would send a strong signal to investors that Alberta is committed to bringing additional resources to the table to attract global low-carbon capital.

3. Develop a comprehensive low-carbon industrial strategy based on the principles in Alberta's ERED Plan that targets high-priority sectors.

A modern industrial strategy must go beyond tax credits and contracts for difference.

Alberta's industrial strategy should build on the strengths of the ERED Plan and Emissions Reduction Alberta (ERA)'s Technology Roadmap, and TIER can be the centrepiece — but it will require additional elements. First, Alberta should establish new mechanisms for close coordination with industry, Indigenous communities, and labour; joint establishment of sectoral economic targets; and detailed analysis to identify and address supply chain-specific bottlenecks, align policies, and calibrate incentives. Each sector is unique, and will require different policy tools. It takes careful work to get things right. Deep analysis of the opportunities and market conditions in priority sectors should be co-developed with stakeholders. This work should be supported by rigorous, third-party analysis.

The Alberta Oil Sands Technology and Research Authority is an excellent example of well-executed industrial policy. This type of collaboration between industry and government to advance technology for economic benefits can be adapted to the challenge of net-zero industrial policy. It could serve as the basis of a made-in-Alberta strategy.

Alberta can also leverage the federal ITCs by offering targeted, calibrated support to key sectors. The data and tools in this working paper provide a foundation that can be used to identify sectors that require further strategic attention. Delivered swiftly, a strategic mix of ITCs, PTCs, and CCfDs embedded in an overarching industrial strategy can get the most out of Alberta's competitive assets and help the province thrive in a decarbonizing world.

Introduction

Alberta risks missing out on the global rush towards low-carbon investment. In particular, the US *Inflation Reduction Act* (IRA) has created an urgent need to rethink how the province attracts investor capital and enthusiastic project proponents. Fortunately, Alberta has almost everything it needs to compete in a decarbonizing world — most importantly, its own aspiration to achieve net-zero emissions by 2050.

In the wake of the IRA, Alberta needs a strategy to make its abundant assets work together as a coherent whole, and an implementation plan to accelerate progress. The next decade is critical for this endeavour as new technologies begin to deploy and scale, and global supply chains reconfigure to serve the new low-carbon economy.

Continuing an ongoing collaboration between Clean Prosperity and the Transition Accelerator to measure policy-based decarbonization incentives in Canada and the US, this working paper reports preliminary findings with an exclusive focus on Alberta.

This analysis uses project-based financial models to measure policy-based investment incentives along two dimensions for **nine hypothetical low-carbon projects across three technology classes**. We measure differences in policy-based sources of revenue available to each project in Alberta and one hypothetical US state. **Our primary focus is the bankable gap**: This is the difference between investment incentives in the US and Alberta that are clear *ex-ante*. Federal tax credits are the main source of the bankable gap. The IRA offers a production tax credit (PTC), an investment tax credit (ITC), or both, for all nine projects analyzed.

We also consider aspects of **the total incentive gap**. This accounts for a broader set of investment incentives — both bankable revenue streams like tax credits, and less certain revenue sources, like the sale of carbon credits or offsets generated under Alberta's Technology Innovation and Emissions Reduction (TIER) Regulation. Other grant and loan programs, or in-kind resources can also contribute to the total incentive gap, but we do not measure them in this paper as they are typically one-off investments.

Overall, we find that the IRA has given competing US jurisdictions a bankable advantage over Alberta for a number of critical low-carbon technologies.

TABLE 1: Measuring the bankable gap with the US for low-carbon technologies

Technology class	Type	Comparison jurisdiction	Bankable gap[3]
Low-carbon fuels	Blue ammonia	Texas	$0.11/kg ammonia
	Green hydrogen	Montana	$4.09/kg hydrogen
	Sustainable aviation fuel (SAF)	California	$0.53/litre of SAF
Carbon management	Cement with carbon capture, utilization, and storage (CCUS)	Texas	$27/tonne of CO_2e
	Direct air capture (DAC)	Louisiana	$106/tonne of CO_2e
Electricity	Natural gas with CCUS	Iowa	$18/MWh
	Solar	California	$9/MWh
	Wind	California	$17/MWh
	Advanced nuclear	N/A	N/A

To help Alberta respond to the IRA and the broader global shift towards decarbonization, we make three recommendations. Together, they offer a playbook to maximize the power of the TIER carbon-credit market, placing it at the centre of a comprehensive industrial strategy.

We find that financial instruments called carbon contracts for difference (CCfDs) could fully close the bankable gap for a majority of the technologies studied: blue ammonia, cement with carbon capture, utilization, and storage (CCUS), natural gas with CCUS, solar and wind power — although the latter two are competitive in the absence of CCfDs. For green hydrogen, SAF, cement with CCUS, DAC, and natural gas with CCUS, we also model and provide a fully costed estimate of the size of production tax credits (PTCs) required to fully close the bankable gap.

Implemented correctly, CCfDs are low-cost, present minimal financial risk to the government, and can even offer financial upside. Without CCfDs, alternative measures to make Alberta a competitive destination for investment could cost billions of dollars. (See the Conclusion section below for an explanation of CCfDs.)

3 All currency amounts in this working paper are in Canadian dollars, except where otherwise noted. For the assumptions underlying the analysis in this paper, see the Appendix.

Part A: Low-carbon fuels

1. Blue ammonia

FIGURE 1: Average annual gross revenue from policy sources for hypothetical 1 million tonne/year blue ammonia project, 2025-2034 ($ per kg of ammonia)

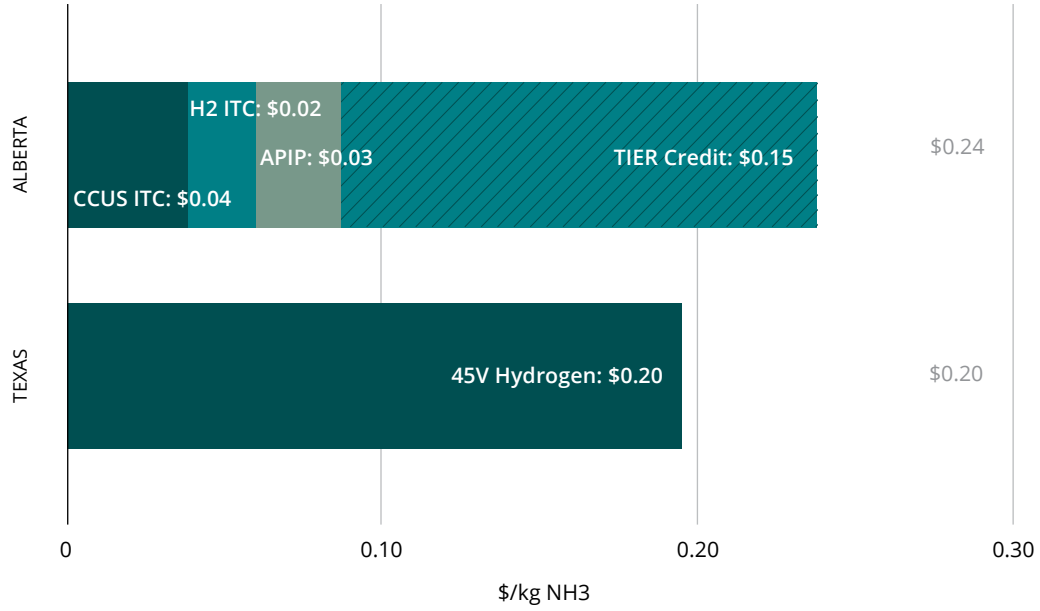


Figure 1 illustrates the investment incentive gap between ammonia facilities equipped with carbon capture in Alberta and Texas. The **bankable gap** with the US is **$0.11 per kilogram of ammonia**.[4] Investors would be leaving over $100 million in bankable revenues on the table if they chose to site this facility in Alberta rather than Texas. The bankable gap arises from a single PTC in the IRA, 45V. Canada's federal ITCs for CCUS ($0.04/kg) and hydrogen ($0.02/kg) narrow the gap somewhat (see footnote for assumptions about credit stacking).[5]

The Alberta Petrochemicals Incentive Program (APIP) is stackable with the federal incentives and is worth $0.03 per kg of ammonia for this modelled project. APIP sets out clear application criteria and the Alberta government states that all eligible facilities will be approved by the program.[6] As such, we treat APIP as a bankable source of revenue for the purposes of this analysis.

4 All figures are rounded to the nearest cent/dollar.

5 Portions of this blue ammonia project are eligible for both the federal CCUS ITC (50% of capital costs) and the hydrogen ITC (15%–40% of capital costs depending on carbon intensity). These tax credits cannot be stacked for any individual piece of equipment, but both can be claimed for different pieces of equipment within a single project. The hydrogen ITC also offers a 15% credit for equipment used to produce blue ammonia. Where a piece of equipment is eligible for more than one tax credit, we assume that proponents claim the CCUS ITC wherever possible.

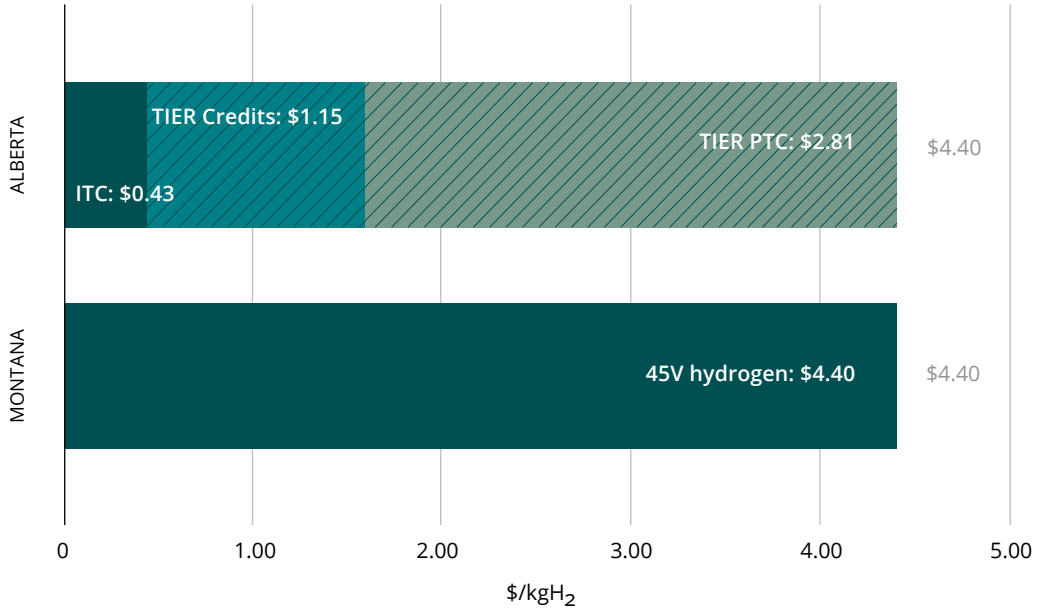
6 Alberta Petrochemicals Incentive Program: Program Guidelines Document

TIER credits generated by this project would represent the largest tranche of potential revenue — but uncertainty about their future value means they are not yet bankable. If TIER credits became a bankable source of revenue in Alberta, it could create a **bankable advantage** worth **$0.04/kg** of blue ammonia.

Alberta's goal as stated in the Emissions Reduction and Energy Development (ERED) Plan is to develop large export markets for blue hydrogen and its derivatives[7]. This makes creating a bankable advantage for blue ammonia all the more vital, since Alberta's blue ammonia exports would mostly be competing in highly competitive international markets. As an alternative to guaranteeing the future value of TIER credits using CCfDs, Alberta could develop specific incentives for export-oriented ammonia projects to close the bankable gap only where global competitiveness is paramount.

2. Green hydrogen

FIGURE 2: Average annual gross revenue from policy sources for hypothetical 300,000 tH_2/year green hydrogen project, 2025-2034 ($ per kg of hydrogen)



Analysts have singled out the 45V credit for emissions-free hydrogen as uniquely generous within the IRA's suite of tax credits. Figure 2, which compares policy-source revenue available to hypothetical green hydrogen facilities in Alberta and Montana,[8] illustrates this point well. For this facility, we estimate the IRA's 45V clean-hydrogen PTC is worth $4.40/kg$H_2$ per year over 10 years. Canada's ITC would be worth $0.43/kg$H_2$ for this project. The **bankable gap** is therefore **$3.97/kg$H_2$**.

7 A comparison of the incentives for blue hydrogen production in Alberta and Texas is provided in our previous report, Creating a Canadian Advantage.

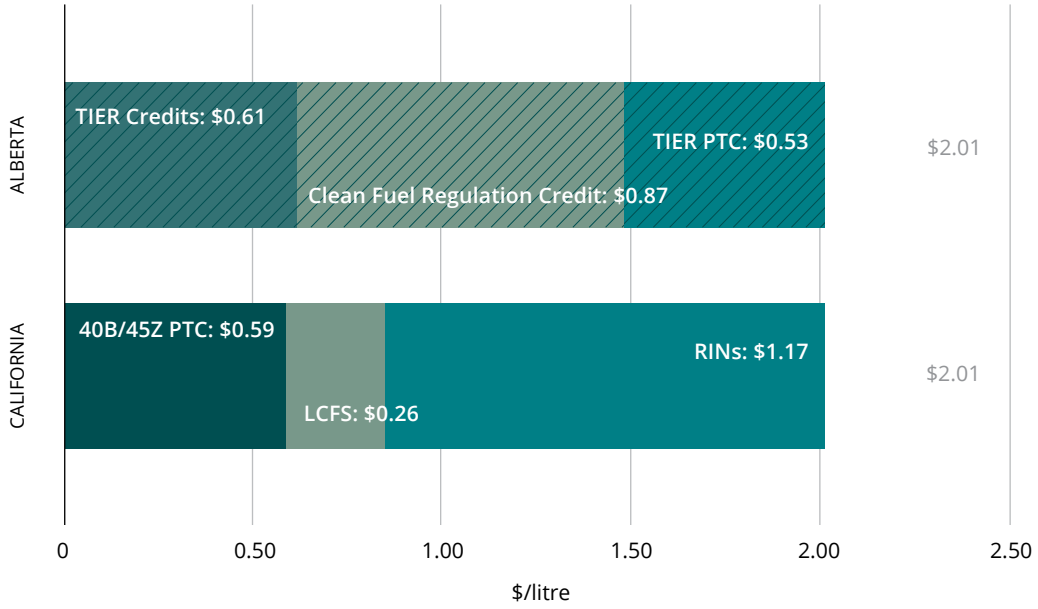
8 Hydrogen is expensive and inefficient to transport over longer distances, so North American markets are more likely to serve regional "hubs". A proposed project in Alberta would more likely view Saskatchewan or Montana as alternative locations, rather than California or Texas.

Fully closing the bankable gap for this type of project would require guaranteeing the value of TIER credits (worth $1.15/kg$H_2$) plus a 10-year PTC worth $790 million in year 1, rising to $944 million in year 10 — almost double TIER's current annual revenues.

Alberta is dealing with a long-term, structural disadvantage for green hydrogen production.[9] The IRA makes it simply too expensive for Alberta to compete. However, Alberta can still benefit if 45V can successfully drive down the cost of electrolyzers, fuel cells, wind turbines, solar panels, and other components used in green hydrogen production. Manufacturing 1 kg of green hydrogen costs around US$5.[10] The US Department of Energy has set a cost target of US$1 per kg by 2030.

3. Sustainable aviation fuel (SAF)

FIGURE 3: Average annual gross revenue from policy sources for hypothetical gasification with forest residues project, 150 million litres/year, 2023-2027
($ per litre of SAF produced)



The total incentive gap for SAF — or any novel biofuel facility — is difficult to calculate because both policy-based revenue sources in Alberta are highly uncertain. A SAF production facility of the scale described in Figure 3 would be a first-of-kind project in Alberta. As a result, there are no established facility benchmarks under TIER,[11] and challenges navigating the immature credit markets under the new Canadian Clean

9 Most of the tax credits in the IRA expire between 2032 and 2034. The 45V PTC is an exception. Although the 45V credit expires in 2033, a green hydrogen project that enters service in 2032 is still eligible to claim 10 years worth of PTCs through 2042.

10 International Renewable Energy Agency. 2021. Making the breakthrough: Green hydrogen policies and technology costs.

11 Per Alberta's standard for developing benchmarks, first-of-kind facilities producing novel products can apply for a global best-in-class high-performance benchmark (HPB) based on operations in other jurisdictions. New HPBs are considered during regulatory reviews or can be issued through a Ministerial Order at any time. Under facility-specific benchmarks, facilities have perverse incentives to "come in high" and produce more emissions in the years where their benchmarks are being established, and then retrofit afterwards to ensure performance way below the established benchmark. This type of gaming risk should be accounted for with any first-of-kind facility that cannot use an HPB.

Fuel Regulations (CFR). **The only bankable sources of revenue for this SAF project** in either jurisdiction are the 40B and 45Z PTCs in the US, which create **a bankable gap of $0.59 per litre**.

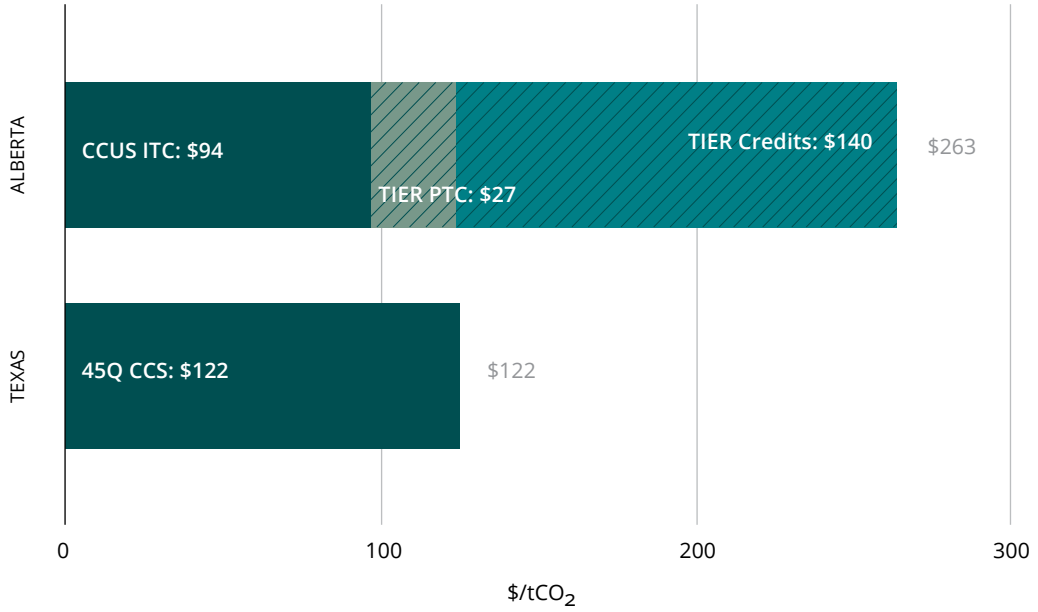
Even with optimistic assumptions about credit prices across TIER and the CFR, revenue from California's Low Carbon Fuel Standard (LCFS) and Renewable Identification Number (RINs) credits creates a **total incentive gap** of **$0.53 per litre** for the five-year period 2023-2027 — with the assumption that the US tax credits for SAF expire as planned in 2027.

With the assumed credit values for TIER and the federal CFR, fully closing the bankable gap in Alberta would require a five-year PTC worth an average of $0.53 per litre of 95% decarbonized SAF. Similar to 45V and Canada's federal hydrogen ITC, this PTC should be indexed to the fuel's carbon intensity, offering the largest incentives for fully decarbonized fuels. A PTC of this size indexed to inflation would cost $77 million in year one and $82 million in year five. Without the federal CFR, the value of the PTC required to fully close the bankable gap would roughly triple. Because the IRA incentives for SAF last only for five years, it would also be possible to close the bankable gap by offering a smaller PTC over a longer timeframe.

Part B: Carbon management

4. Cement with CCUS

FIGURE 4: Average gross revenue from policy sources for hypothetical 1 $MtCO_2$ cement CCUS project, 2025-2034 ($ per tonne of captured CO_2)[12]



Carbon capture is essential for fully decarbonizing cement manufacturing. The **bankable gap** for equivalent 1 $MtCO_2$ CCUS projects attached to cement plants in Alberta and Texas is **$27/tCO$_2$** on average over a 10-year period.

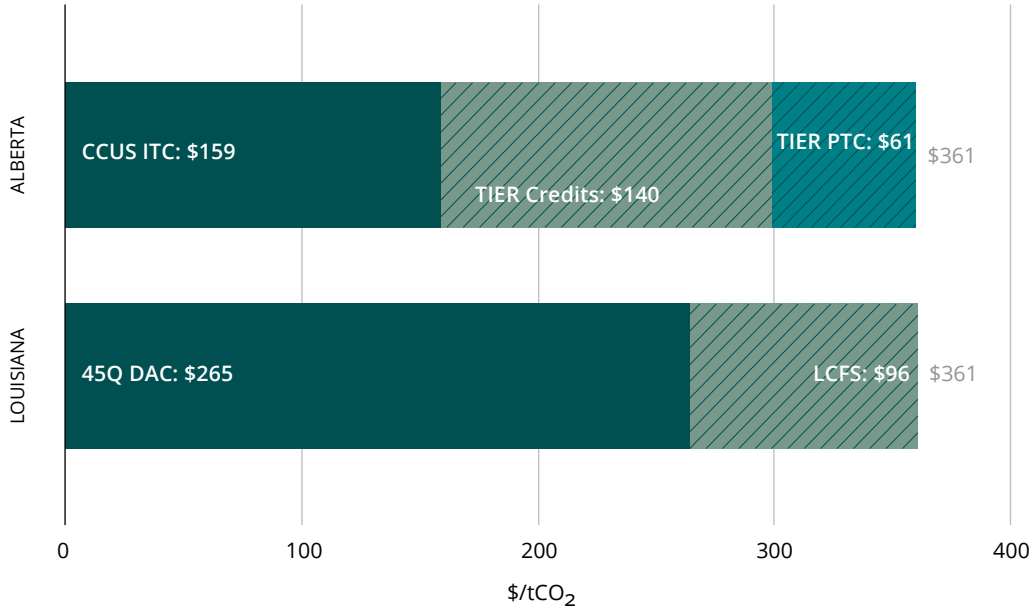
If we consider total incentives, average revenue per tonne of captured CO_2 could be nearly twice as high in Alberta ($234/tCO$_2$ based on the combined value of the CCUS ITC and TIER credits) relative to a Texas facility ($122/tCO$_2$). But this additional revenue is uncertain, as it requires that demand for TIER carbon credits will consistently exceed supply.[13] If the value of TIER credits were guaranteed, it would open up a **bankable advantage** for Alberta of **$112/tonne**.

In the absence of a program to make TIER credits fully bankable, a 10-year PTC worth an average of **$27/tonne** could fully close the bankable gap for this hypothetical cement facility. A PTC of this size indexed to inflation would cost $25 million in year one and rise to $30 million in year 10, **for a total cost of $180 million over 10 years**.[14] Alberta's forthcoming carbon capture investment program could fill this bankable gap. However, it would become unnecessary if a CCfD program were implemented.

12 Includes a negligible $2/tCO$_2$ for avoided compliance costs in Alberta, unlabelled in the figure.
13 In this model, we assume the headline carbon price freezes at $170/tonne in 2030 while the sectoral benchmark continues to tighten. This results in diminishing annual revenue from credits past 2030.
14 Estimate in nominal dollars.

5. Direct air capture (DAC)

FIGURE 5: Average annual gross revenue from policy sources for hypothetical 1 $MtCO_2$ DAC project, 2025-2034 ($ per tonne of captured CO_2)



Direct air capture (DAC) built significant momentum in 2023. Two first-of-kind DAC projects are in development on the US Gulf Coast after receiving a US$1.2 billion grant from the US Department of Energy in August. Project Cypress in Louisiana and the South Texas DAC Hub will both remove up to 1 Mt of CO_2 annually — each project is 250 times larger than any DAC facility currently operating.

The **bankable gap** for one of these 1 $MtCO_2$ DAC projects between Alberta and Louisiana averages **$106/tCO_2$** over a 10-year period. Even when we assume a best-case scenario for Alberta — where TIER credits trade at 95% of the federal carbon price — the average revenue per tonne of captured CO_2 is still **17% lower** for a DAC plant in Alberta ($299/tCO_2$) compared to the same plant in Louisiana, which could also be eligible to generate credits under California's LCFS ($361/tCO_2$).

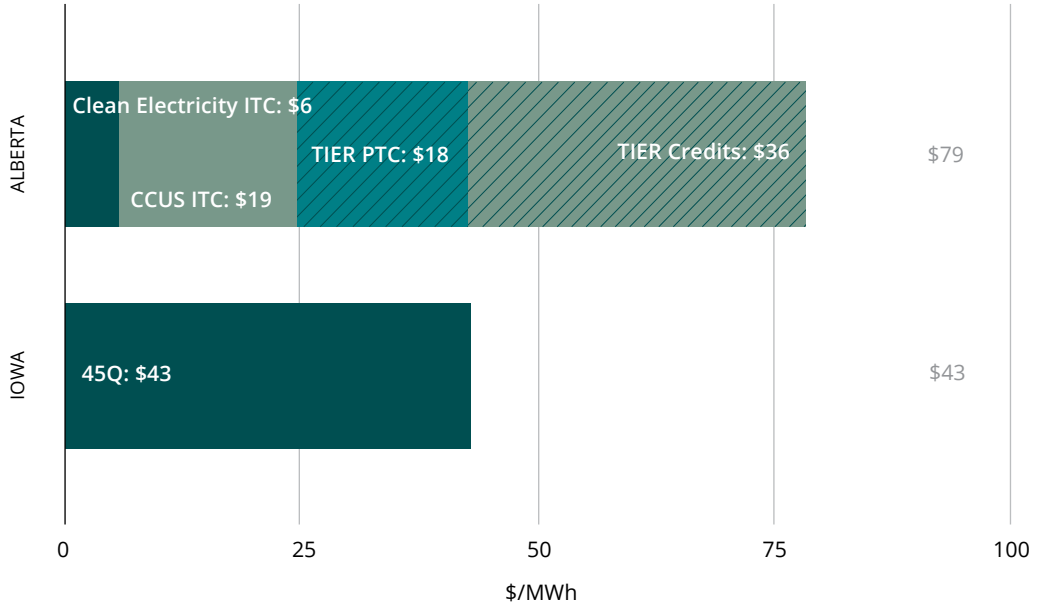
Our analysis indicates that getting any commercial carbon dioxide removal project off the ground in Alberta will require both CCfDs and a supplementary PTC equivalent. When stacked on top of a CCfD, a 10-year PTC for DAC in Alberta worth an average of $61/tCO_2$ could fully close the bankable gap with an equivalent facility in Louisiana.[15] A 10-year PTC of this size indexed to inflation would cost $55 million in year one and $66 million in year 10.

15 Fuels produced from captured carbon would be eligible for CC1 credits under Canada's Clean Fuel Regulations, but this is not likely an economically viable choice for DAC operations in the near term. Louisiana figures include estimated value of credits available via the California LCFS.

Part C: Electricity

6. Natural gas with CCUS

FIGURE 6: Average annual gross revenue from policy sources for a hypothetical 900 MW natural gas combined cycle power plant with 95% carbon capture, 2025-2034 ($ per MWh of electricity generated)



Abated natural gas will likely be a significant component of Alberta's future electricity mix, but deployment of commercial CCUS has progressed relatively slowly so far. Strengthening policy support — including carbon pricing and the US IRA — has generated a surge of investments in recent years.[16] There are about three dozen CCUS projects planned for gas-fired power plants, with six of these projects located in Alberta. One commercial power station is currently equipped with CCUS — SaskPower's coal-fired Boundary Dam Power Station.

The **bankable gap** for a 900 MW natural gas power plant with carbon capture in Alberta and Iowa is **$18 per MWh** on average over a 10-year period. If the value of TIER credits were guaranteed, Alberta would gain a **bankable advantage** of **$18 per MWh** for this project when stacked on top of federal ITCs.[17]

In the absence of a program to make TIER credits fully bankable, we estimate that a 10-year PTC worth an average of $18/MWh (or $53/tonne of CO_2e) could fully close the bankable gap for this modeled facility. A PTC of this size indexed to inflation

16 Per the International Energy Agency: Estimated total investment in CCUS projects at advanced stages of planning is more than US$27 billion, almost double the investment in projects commissioned since 2010.

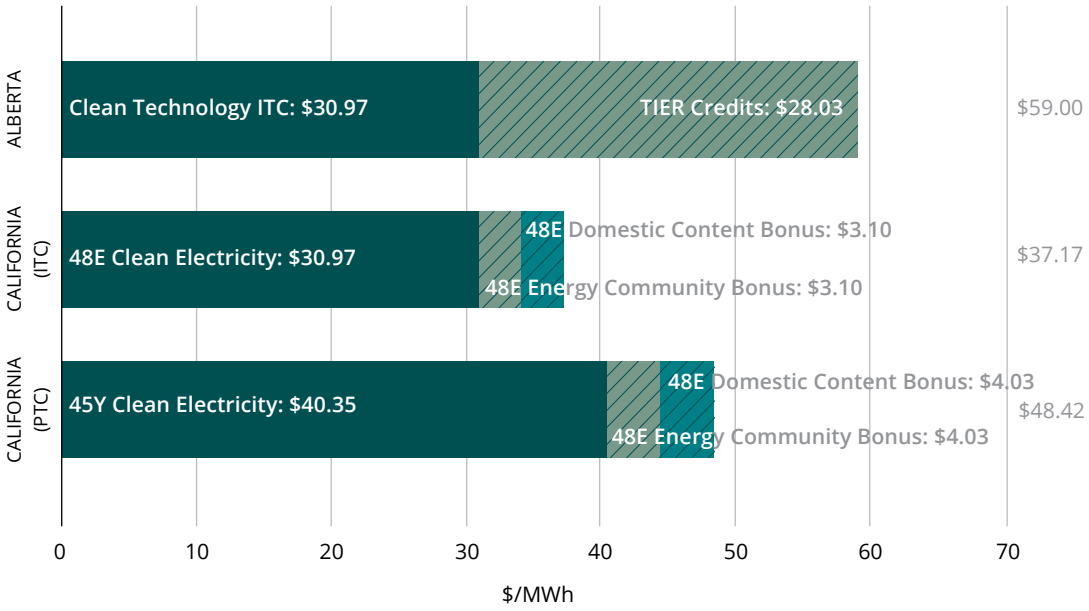
17 As with other projects that include a CCUS component, we assume that tax credits cannot be stacked for any individual piece of equipment, but that different credits can be claimed for different pieces of equipment within a single project. Here, we assume that the capex for the electricity-generation portion of the project claims the federal clean electricity ITC, while capex for the CCUS portion of the project claims the federal CCUS ITC.

would cost $72 million in year one and rise to $86 million in year 10, **for a total cost of $786 million over 10 years**.[18]

Natural gas facilities equipped with carbon capture will play a different role on Alberta's grid than unabated natural gas facilities do.[19] In addition to closing the bankable gap, Alberta must ensure that access to carbon transportation and storage infrastructure does not become a bottleneck for project proponents, since multiple sectors will be competing for transportation capacity.

7. Solar

FIGURE 7: Average gross revenue from policy sources for a hypothetical 300 MW solar energy project, 2025-2034 ($ per MWh of electricity generated)



Even with the incentives in the IRA, solar development in Alberta is largely competitive with the US. Real-world evidence backs this up — installed solar capacity on Alberta's grid grew by 35% in 2022. Canada's most productive solar resources are in southeastern Alberta.

We calculate a **bankable gap** of **$10/MWh** between Canada's ITC and the US PTC. However, this gap is unlikely to divert investment away from Alberta. Given the speed at which the cost of solar has fallen in recent years, both sets of incentives are more than adequate premiums to entice solar developers, even if the US PTC is the most generous.

US proponents have the flexibility to choose between the IRA's 48E ITC or 45Y PTC for clean electricity. The PTC would offer more bankable revenue to a majority of solar

18 Estimate in nominal dollars.

19 CCUS equipment is energy intensive and can reduce a natural gas facility's efficiency by nearly a quarter and increase the cost of electricity production by up to 70%. Lower capacity factors can amplify these impacts, and ramping up and down quickly to meet demand peaks is hard on the equipment. Natural gas with CCUS is therefore likely better suited for baseload power than for peaker power.

projects over the life of the project. However, PTCs may be less preferable in some circumstances. Projects sited on less productive land, projects with unusually high capex, or projects requiring greater levels of working capital in the earlier stages may prefer the ITC.

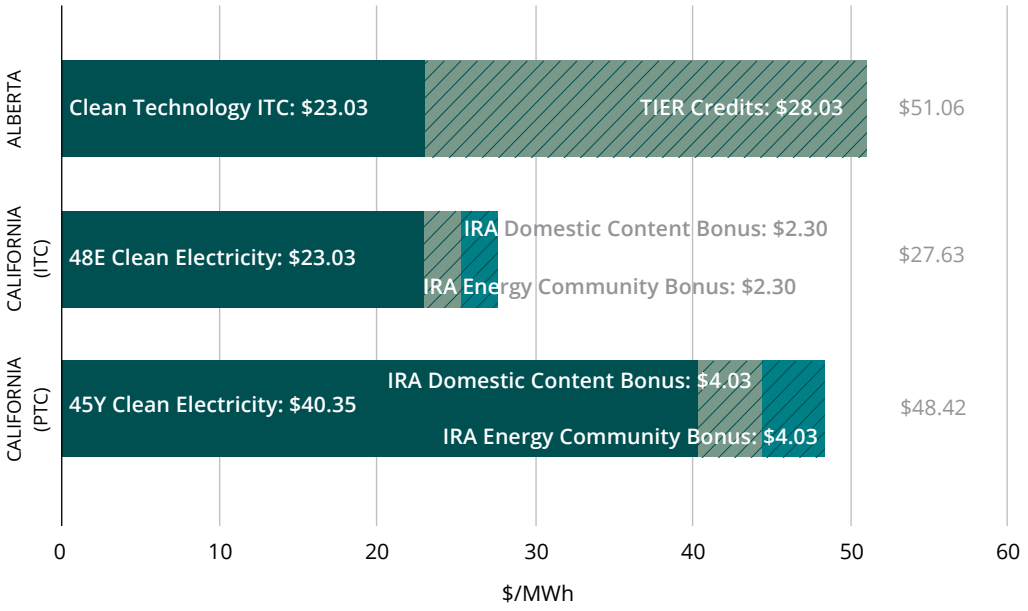
The IRA also offers 10% bonus credits for clean electricity projects that satisfy domestic content requirements, and projects that are located in "energy communities" containing brownfields or recently retired coal plants and mines. The value of these bonus credits are shown for illustration in Figure 7.

The bonus credit system is a feature that the Alberta government could consider mimicking if designing its own ITCs, PTCs, or other policy supports. The government could consider offering bonus credits or preferential incentives to support Indigenous economic partnerships, regions of the province with declining tax bases or depressed wages, or in areas proximal to critical infrastructure.

If the future value of TIER credits were guaranteed through CCfDs or a similar program, it could open up a **bankable advantage** of over **$10/MWh** for Alberta-based projects, even accounting for bonus credits offered under the IRA.

8. Wind

FIGURE 8: Average annual gross revenue from policy sources for a hypothetical 300 MW wind energy project, 2025-2034 ($ per MWh of electricity generated)



Wind power has a distinct cost structure from solar and costs less per MW to install in Alberta, so is worth examining separately. This cost structure creates a wider bankable gap between the US production tax credit and Canada's investment tax credit. Wind projects have a **bankable gap** of **$17/MWh** versus the US PTC, rising to **$25/MWh** if the US project qualifies for the domestic content and energy community bonus credits described in the section above. The US ITC offers a lower-value

incentive than the PTC, but could be preferable under certain circumstances (see the section on solar power above).

As with solar, we do not anticipate that the bankable gap will result in diversion of wind investment from Alberta towards the US. Canada's federal ITCs are sufficient to attract investment in new wind projects, even with the bigger incentives on offer though the IRA.

If the future value of TIER credits were guaranteed, Alberta would open up a small **bankable advantage**, versus the US PTC, of just under **$3/MWh** for wind projects.

9. Advanced nuclear

The term *advanced nuclear* covers both small modular reactors (SMRs) and Generation IV reactors, which experiment with very high heats, novel fuels, and exotic moderators and coolants, such as molten salts.

Alberta has expressed interest in establishing a commercial nuclear sector, and is a signatory to the interprovincial strategic plan on SMRs. Emissions Reduction Alberta (ERA) recently announced $7 million in funding toward a $27 million SMR feasibility study with Cenovus. An advanced nuclear project would be eligible for the federal ITC for clean electricity as well as the federal ITC for clean technology manufacturing, which covers nuclear energy equipment.

Any new advanced reactor that comes online in the US can claim the IRA's 45U Zero-Emission Nuclear Power PTC or the 45Y Clean Electricity PTC under the IRA. Both are worth up to US$15/MWh with varying conditions attached. The IRA contains a third PTC for nuclear, 45J, designed to extend the lifespans of specific reactors in the US's aging nuclear fleet.[20] The advanced nuclear project furthest along in the US is X-Energy and Dow's partnership to build a demonstration reactor on the Gulf Coast.

Advanced nuclear remains in its very early stages. Under current policy conditions, the **bankable gap is not a relevant metric for evaluating investment incentives for nuclear energy** in Alberta, for three primary reasons.

First, for an advanced commercial nuclear reactor in Alberta, the construction timelines are not aligned with the lifespan of the IRA or Canada's federal ITCs. The other low-carbon projects in this paper are modelled through 2034, when the IRA and federal ITCs sunset. A first-of-kind advanced reactor would take well over a decade to bring on to the Alberta grid. As the Alberta Electric System Operator notes in its 2022 Net-Zero Emissions Pathways Report, SMRs "may struggle to achieve decarbonization objectives within the 2035 timeframe."

Second, competition within the nuclear sector is unlike other low-carbon sectors. No country in the world has successfully built out a nuclear industry without substantial government coordination and financial backing. Nuclear projects have capex-heavy

20 45J is called the advanced nuclear tax credit, which is a misnomer. 45J defines an "advanced nuclear power facility" as any taxpayer-owned facility placed in service between 2005 and 2020. The maximum incentive is US$15/MWh.

cost structures that require continuous access to low-cost capital. The sector has struggled with cost overruns for decades, stretching and occasionally breaking the budgets of utilities and project developers.

Many commercial projects use public-private consortia models to spread out these financial risks. As such, jurisdictions are not directly competing with one another for investment in their nuclear sectors in the same way they are for other project types modeled in this paper. This consortium structure underpins the plan to construct four SMRs at Darlington Nuclear Generation Station in Ontario. This deep collaboration between the Ontario and federal governments, GE Hitachi, Ontario Power Generation, Aecon, and SNC-Lavalin, cannot be replicated in any other jurisdiction.

Lastly, an Alberta-based nuclear reactor would face unusually high regulatory hurdles, even when compared to other first-of-kind projects modeled in this paper. Regulatory frameworks need to be designed from scratch across several provincial agencies, notably the Alberta Energy Regulator and the Alberta Electric System Operator. This work remains in its early stages.

Unlike other electricity projects, an advanced nuclear reactor would also need to proceed through the federal Impact Assessment Agency and the Canadian Nuclear Safety Commission. Siting, community and Indigenous engagement, supply chain development, financing arrangements, insurance provisions, lifecycle management, and long-term waste disposal would all require substantial upfront planning before permitting and licensing could proceed.

Conclusion: Leverage TIER as a strategic asset to unlock low-carbon investment

Alberta can take several near-term actions to attract larger flows of low-carbon investment. This work starts with carbon contracts for difference (CCfDs), a kind of insurance policy on the future value of carbon credits. CCfDs give companies the confidence that they can generate dependable revenues from selling credits, and incentivize them to make big investments in decarbonization (see below for a detailed explanation of CCfDs).

Implemented correctly, CCfDs are low-cost, present minimal financial risk to the government, and can even offer financial upside. Without CCfDs, alternative measures to make Alberta a competitive destination for investment could cost billions of dollars.

Mitigating carbon-market risks using CCfDs would open up advantages for Alberta and Canada in key strategic sectors — including ammonia and other petrochemicals, low-carbon fuels, and carbon management technologies. Combined with a smart low-carbon industrial strategy that boosts the power of TIER, CCfDs can help make Alberta a low-carbon investment destination of choice.

Alberta should also maximize the power of the TIER market by deepening the industrial strategy outlined in the ERED Plan and ERA's Technology Roadmap. Sector-specific approaches should be developed, but they should treat Alberta's strategic assets as a package. For example, every additional unit of electricity produced from cheap renewable energy frees up natural gas molecules for higher-value applications like blue petrochemicals, or saves underground pore space for higher-value applications of CCUS. An effective strategy for priority sectors would consider these types of interactions, develop clear targets based on deep technical analysis of the economic opportunities and challenges, and devise mechanisms for effective coordination with the private sector and other levels of government. A strategy that considers all of Alberta's strategic economic assets as a whole can help accelerate the growth of new industries.

Recommendation 1: Make TIER a bankable asset for more low-carbon projects

Project proponents and investors currently lack sufficient confidence that the TIER market will support credit prices close to the $170 headline carbon price that Alberta has committed to for 2030. Clean Prosperity's analysis shows that this lack of confidence is well-founded, indicating significant risk of credit/offset oversupply within TIER as more low-carbon projects come online. Based on the expectation of softening demand for credits, proponents are holding back on billions in low-carbon investments. There is a clear and urgent case for ensuring that credit prices continue to rise and, more importantly, instilling confidence in firms and investors that there will be robust demand for the credits their projects generate.

CCfDs can help by systematically closing the bankable gap for a range of projects. The 2023 federal budget committed to consult on a program of broad-based CCfDs to address the problem of investor confidence, though no formal consultation process has begun. Alberta stands to benefit tremendously from CCfDs and should take steps to ensure their successful implementation and augment their impact:

A. **Bring CCfDs to the TIER market** — whether working with the federal government, through its own program, or a combination of both, Alberta should ensure a CCfD program is operational in 2024. The federal government is actively considering CCfDs; Alberta should do what's needed to persuade the federal government to move forward with that program, including: making clear the benefits the program will bring, offering advice on design, and assuring the federal government that Alberta will not take any actions to undermine the program. In parallel, the Alberta government should begin developing its own provincial CCfD program in case the federal program does not materialize.

B. **Direct Alberta Carbon Registries to regularly publish the average prices of credits traded on the TIER market.** TIER currently lacks price transparency, which is essential for any efficient market, and for signing CCfDs that are struck against credit prices. Publishing rolling average credit prices similar to California's LCFS would improve price visibility for all market participants and strengthen the price signal. At a minimum, Alberta Carbon Registries should publish the average market prices of Emissions Performance Credits, sequestration credits[21], and capture recognition tonnes on a regular basis.

C. **Develop new high-performance benchmarks (HPBs) within TIER for emerging sectors.** These benchmarks help determine the carbon charges that particular classes of industrial facilities must pay on their emissions in Alberta. TIER has HPBs for hydrogen, electricity, and industrial heat. Designing new HPBs — particularly for low-carbon fuels — would provide greater upfront clarity for new projects in markets poised for rapid growth, helping to crowd in first-of-

21 Sequestration credits are a special class of carbon offset that can be retired to meet TIER compliance obligations. The CO_2 must be geologically sequestered at a large-emitter or opt-in facility regulated by TIER, such as an oilsands facility or fossil fuel power plant. A sequestration credit is stackable under the federal Clean Fuel Regulations. TIER's sequestration credits can be converted into capture recognition tonnes, which covered and opted-in facilities can count against their net emissions.

kind investments that can take advantage of TIER, CCfDs, and ITCs. CCfDs can provide certainty around the price that new low-carbon projects will receive for their TIER credits; new HPBs can provide greater certainty of the volume of credits they could expect to generate.[22]

D. **Define a price path for TIER beyond 2030.** While ERED committed to raising Alberta's carbon price to $170 per tonne by 2030, it's unclear where the price will go after that. Investors need to know the future trajectory of the carbon price to predict long-term project revenues. A defined path for the carbon price through the 2030s would help establish TIER as an asset capable of delivering long-term value to low-carbon projects.

What are Carbon Contracts for Difference (CCfDs)?

A carbon contract for difference (CCfD) is an agreement between government (federal or provincial) and the private-sector proponent of a new low-carbon or decarbonization project, like a blue ammonia production facility.

A CCfD is like an insurance policy that guarantees the future value of carbon credits, which project proponents can use to generate revenue. The government guarantees a specific credit price for a specific period of time (ideally 10 to 15 years), and the CCfD is only activated if the average market price of credits differs from this guaranteed price.

Any payment obligations arising from CCfDs are settled on a regular basis. The longer the duration of the CCfD, the greater the certainty offered to firms.

If the average market price of carbon credits is lower than the price agreed in the contract, then the government will pay the difference to the project proponent. If the average credit price is higher than the contract price, then the proponent will pay the government.

In this way, CCfDs help mitigate the carbon-pricing risks faced by proponents of new low-carbon or decarbonization projects that are relying on carbon-credit revenue to make their projects economic.

While CCfDs come with potential cost impacts, the government has the ability to avoid payouts. As long as the government maintains the carbon-price trajectory and ensures that carbon-credit markets operate efficiently, its CCfDs need never be exercised.

22 See the section on SAF (above) for an example of how setting HPBs can benefit emerging sectors.

Examples

Government and Company Z sign a CCfD in 2023, guaranteeing the value of a specified quantity of Company Z's carbon credits at $150/tonne in 2030.

Example 1: Carbon credits are worth less for Company Z

In 2030, the average market price of carbon credits is $149/tonne ($1 below the price set in the CCfD).

The government must pay $1/tonne to Company Z, multiplied by the quantity of carbon credits specified in the CCfD.

Example 2: Carbon credits are worth more for Company Z

In 2030, the average market price of carbon credits is $151/tonne ($1 above the price set in the CCfD).

Company Z must pay $1/tonne to the government, multiplied by the quantity of carbon credits specified in the CCfD.

Example 3: Carbon credits are worth exactly as agreed

In 2030, the average market price of carbon credits is $150/tonne.
No payments are made by either party.

Note

This example CCfD design is simplified for illustration purposes. For a more detailed exploration of CCfD design considerations, see Closing the Carbon-Pricing Certainty Gap by Clark et al. (2022).

Recommendation 2: Apply 100% of present and future TIER revenues to support decarbonization

TIER is a unique strategic asset for Alberta. No other province possesses a carbon market close to this size. The TIER fund investment program has invested $1.48 billion since 2019 — much of it in low-carbon technology.[23] Alberta's ERED Plan has defined TIER's headline price path for the next seven years. If Alberta ensures that credit prices rise alongside this headline price, TIER revenues could grow significantly.

23 Annual Report, Government of Alberta, 2022-2023

Currently, a sizable portion of TIER revenues are transferred to the province's General Revenue Fund for deficit reduction.[24] This approach should be reconsidered in light of Alberta's strengthened fiscal position.

We recommend earmarking 100% of future TIER revenues to accelerate the decarbonization of Alberta's industrial base through the TIER Fund and other agencies. This is a transparent and fiscally straightforward approach to implementing a strengthened industrial strategy. The TIER Fund currently supports projects, programs, and R&D initiatives across many sectors. But larger pools of capital and funding for novel policy tools that can more systematically and strategically attract new forms of low-carbon investment are necessary to maximize TIER's potential.

Some of these new policy tools could include strategic ITCs, PTCs, and collateral for CCfDs. These can be integrated with Alberta's current approach of supporting discrete investments. When nested within a broader industrial strategy, discrete investments can complement economy-wide policies like broad-based CCfDs.

When considering administration of these new instruments, strong preference should be given to existing agencies and provincial Crown corporations with proven delivery models for investment in decarbonization. Both ERA and Alberta Innovates should be considered for additional funding under this new approach.

Committing to this full earmarking in the 2024 provincial budget would send a strong signal to investors that Alberta is committed to decarbonization and that the province is bringing additional resources to the table in this global investment race. Rather than layering on additional bespoke low-carbon policy supports through the General Revenue Fund and annual budget planning, the Alberta government could more effectively wield TIER's financial might.

Recommendation 3: Develop a comprehensive low-carbon industrial strategy based on the principles in Alberta's ERED Plan that targets high-priority sectors

An effective provincial industrial strategy is more than tax credits and contracts for difference. Alberta's industrial strategy should position the province to succeed in the economy of the 21st century by identifying long-term engines of economic power and prosperity. Alberta's industrial strategy should be made in Alberta, but should make full use of federal programs like ITCs that offer additional support to key sectors.

Alberta has all the critical elements of a competitive, leading economy, but they must be focused and mobilized strategically. A modern industrial strategy involves developing outcome-based targets, detailed financial and policy analysis, and collaboration between government and industry in priority sectors. TIER can be the centrepiece of the strategy, but more components are needed. This approach to

24 Annual Report, Alberta Environment and Protected Areas, 2022-2023

designing an industrial strategy begins by identifying high-priority opportunity areas: industries where Alberta can compete globally and which could produce significant economic benefits in the form of good jobs and manufacturing value added.

The ERED Plan identifies a number of Alberta's top opportunities in a decarbonizing world. Of these, clean electricity, hydrogen, bioenergy (especially biofuels for aviation), critical minerals, and geothermal energy are all areas where Alberta can and should compete.[25]

The data in this working paper also suggest that DAC and export-oriented hydrogen derivatives require strategic attention. To seize opportunities in these and other priority sectors, Alberta should establish clear pathways and targets. The ERA Technology Roadmap begins the critical work of charting specific pathways in select priority areas. ERA's mandate is to focus on technology areas with the greatest potential to deliver net-zero emissions and economic opportunities for Albertans. Their Roadmap sets goals for technology focus areas like low-carbon fuels, such as "build[ing] on the existing hydrogen market to catalyze a robust clean hydrogen economy, particularly in the context of industrial clusters."

Supporting priority sectors also requires sectoral analyses to identify supply-chain bottlenecks, align policies, and calibrate incentives. Each sector is unique, and will require different policy tools. It takes careful work to get things right.

Finally, a modern industrial strategy should be advanced through close, strategic collaboration between government, industry, Indigenous communities, and labour. This work should be complemented by rigorous, third-party analysis and is best mediated by independent expertise that can provide deep analytics and candid advice.

The Alberta Oil Sands Technology and Research Authority (AOSTRA) offers a good model for collaboration between industry and government to unlock new industries through technological advancement.[26] Adapted to the challenge of net-zero industrial policy, it could serve as a template for a new made-in-Alberta strategy.

Such initiatives require political will and must be given the time and resources needed to succeed. If elevated in this way, they can be used to solve difficult problems. A well-designed and well-executed industrial strategy shares strategic and financial responsibility between governments, Indigenous communities, industry, and other stakeholders. Alberta requires a broad mobilization to effectively compete in a decarbonizing world.

25 Allan, B., Eaton, D., Goldman, J., Islam, A., Augustine, T., Elgie, S., and Meadowcroft, J. (2022). Canada's Future in a Net-Zero World: Securing Canada's Place in the Global Green Economy. Smart Prosperity Institute, Transition Accelerator and Pacific Institute for Climate Solutions. https://transitionaccelerator.ca/canadas-future-in-a-net-zero-world/

26 Hastings-Simon, S. 2019. Industrial Policy in Alberta: Lessons from AOSTRA and the Oil Sands. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3480703

Appendix: Modelling assumptions

This appendix outlines the major assumptions made in modelling the incentive gaps for low-carbon technology between Alberta and the United States; however, it is not an exhaustive list. For questions about the modelling methodology, please contact the authors.

US policy incentives

- All models assume that the IRA's prevailing-wage and apprenticeship requirements are satisfied, in order to maximize the value of US tax credits. Bonus credits for domestic content requirements and energy community requirements are not satisfied unless explicitly noted.
- Blue ammonia: The US IRA does not offer a specific credit for ammonia. The intermediate product (blue hydrogen) is what allows the proponent to claim the 45V PTC.
- DAC: 45Q production tax credit (PTC): $240 per tonne of captured CO_2, increasing at the rate of inflation from 2026 onwards (bankable).
- DAC: California Low Carbon Fuel Standard (LCFS) credits: $87 per tonne of captured CO_2, assumed to increase at the rate of inflation (not bankable).
- Hydrogen and ammonia: IRA 45V production tax credit (bankable).
- SAF: IRA SAF claims the Blender's tax credit (2023-2024), followed by the Clean Fuels Production Credit (2025-2027) (bankable).
- SAF: California LCFS credits: $87 per tonne of avoided CO_2, assumed to increase at the rate of inflation (not bankable).
- SAF: Renewable Identification Number credits (RINs) at current price, assumed to increase at the rate of inflation (not bankable).

Canadian policy incentives

- All models assume that the prevailing-wage and apprenticeship requirements described in Budget 2023 are satisfied, in order to maximize the value of tax credits.
- DAC: Investment tax credit (ITC) for carbon capture and storage: 60% of capital costs for direct air capture projects (bankable).
- CCUS: ITC for carbon capture and storage: 50% of capital costs for DAC projects (bankable).

- DAC, CCUS, Hydrogen: Offset carbon credits for sale within a provincial industrial carbon pricing system like Alberta's TIER (not bankable due to uncertainty about future credit values).
- SAF: Clean Fuels Regulation, prices estimated at industry standard $300 per tonne of CO_2 (not bankable).
- SAF: Assuming no fuel charge on the carbon-free portion of the fuel under the federal carbon pricing system in a 50% SAF blend jet fuel (as indicated in draft changes; not bankable).
- SAF: TIER Benchmark based on benchmark for jet fuel in California LCFS, declines 2% per year in line with other benchmarks (not bankable).
- Natural gas with CCUS: The portion of the project that is not eligible for the CCUS ITC will claim the clean electricity ITC, for which abated natural gas projects are eligible.

Other

- Ammonia, hydrogen, CCUS, DAC, natural gas with CCUS, solar, wind: Canadian ITC amortized over 10 years to match the duration of the PTC. To enable more direct comparison with the US PTCs, the annualized ITC amounts from the CCUS ITC are scaled up by a cost of capital factor (typically 7%).
- Ammonia, hydrogen, DAC, CCUS, natural gas with CCUS: Carbon credit value assumes an average spread of 5% between credit prices and the headline federal carbon price (optimistic scenario).
- Green hydrogen, SAF, cement with CCUS, DAC, natural gas with CCUS: For modeled PTCs, inflation is set at 2%.
- Solar, wind: Carbon credit value assumes an average spread of 30% between credit prices and the headline federal carbon price (mid-range scenario).
- DAC, CCUS, hydrogen, natural gas with carbon capture, solar, wind: Canadian federal carbon price holds at $170 per tonne after 2030.
- Advanced nuclear: It is not possible to construct a nuclear project in Alberta before 2030.