Improving Carbon Pricing Incentives to *Green* the Economy

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November 15, 2022

Introduction

Are environmental taxes effective? Can carbon taxes reduce emissions *enough* to meet Canada's goals or targets? Will firms and/or consumers really change their behaviour in response to carbon prices? The answer to each of these questions is yes, but with important caveats in each case: yes, carbon taxes are effective, but don't expect people to make the changes they might make in response to a $200 per tonne tax to avoid paying a $20 per tonne tax; yes, carbon taxes can reduce emissions *enough* to meet national or global goals, but that doesn't mean that any carbon tax should expected to achieve that outcome; and yes, firms and consumers will change their behaviour in response to carbon prices, but those changes are buffered by inertia and often swamped by the impacts of other changes in aggregate data.

With respect to whether carbon pricing will be sufficient to meet Canadian or global emissions goals, the question could instead as whether current goals are consistent with what we would reasonably expect given emissions policies currently in place or proposed. At this point, both here and worldwide, the answer is no. In particular for aggressive goals associated with keeping global temperature change to less than 1.5ºC, substantially more aggressive policies than those in place anywhere today will be required. For Canada, we have improved substantially with respect to our long tradition of making aggressive international commitments that we are not prepared to meet through domestic policies, but we have a long way to go.

In addition to matching policies to targets, there are several key elements to the long-term success of carbon pricing in driving down emissions including low-carbon investment certainty and rewards for substitution within sectors. It's also important to keep in mind that well-designed policies may not mean more expensive energy – on the contrary, GHG policies or other related initiatives may significantly reduce the break-even costs of low-emissions alternatives. The purpose of this paper is to demonstrate, through examples and discussion complemented by economic modeling and empirical evidence, the effects of carbon prices and other fiscal policies to green the economy. As such, I begin with an analysis of global and national goals and targets, along with the reasonably expected outcomes of the policies in place today. I follow this discussion with more detailed analysis of the elements listed above. I will consider three major industrial sectors in my analysis: oil sands, electricity, and, to a lesser degree, hydrogen.

In working through this analysis, it is important to remember that, while policies in Canada are an important driver for change, they are not the only important factors. Canada is a small, open economy, and so we are price- and technology-takers on the global scale. Global research, development, and deployment of new technology, from solar panels to electric vehicles, will impact the costs of these technologies as they are deployed in Canada, and thus there is a global external impact on the effectiveness of Canadian policies. And, our economy continues to supply the world with substantial energy, and insofar as the world demands more carbon-intensive energy, Canada's climate change commitments will be harder to meet. At a minimum, Canada will need more stringent domestic policies to counter continued global demand for Canadian resources.

Policies to match targets: the marginal cost of national and global goals

Meeting global goals to mitigate climate change, specifically the to prevent global temperature increases of more than 2ºC and to strive to limit increases to 1.5ºC set in the Paris Agreement of the parties to the United Nations Framework Convention on Climate Change (UNFCCC, 2015), will require a substantial, global energy transition. The same is true of efforts to meet our national GHG emissions targets (Environment and Climate Change Canada, 2021) and sector-level commitments including a cap on oil and gas emissions and proposed clean electricity standards (Government of Canada, 2022a, 2022b).

Consider first the magnitude of the global energy transition required to meet widely-cited climate change goals, as shown in Figure 1. Mitigating climate change implies, at least in the median scenarios examined for the Intergovernmental Panel on Climate Change (IPCC, 2022) report, lower growth in total energy supplies, with a significant expansion in emissions-free (renewables and nuclear) sources of energy, along with a rapid phase-out of coal and decline in use of oil and gas compared to those cases where the world does not act as aggressively on climate change.

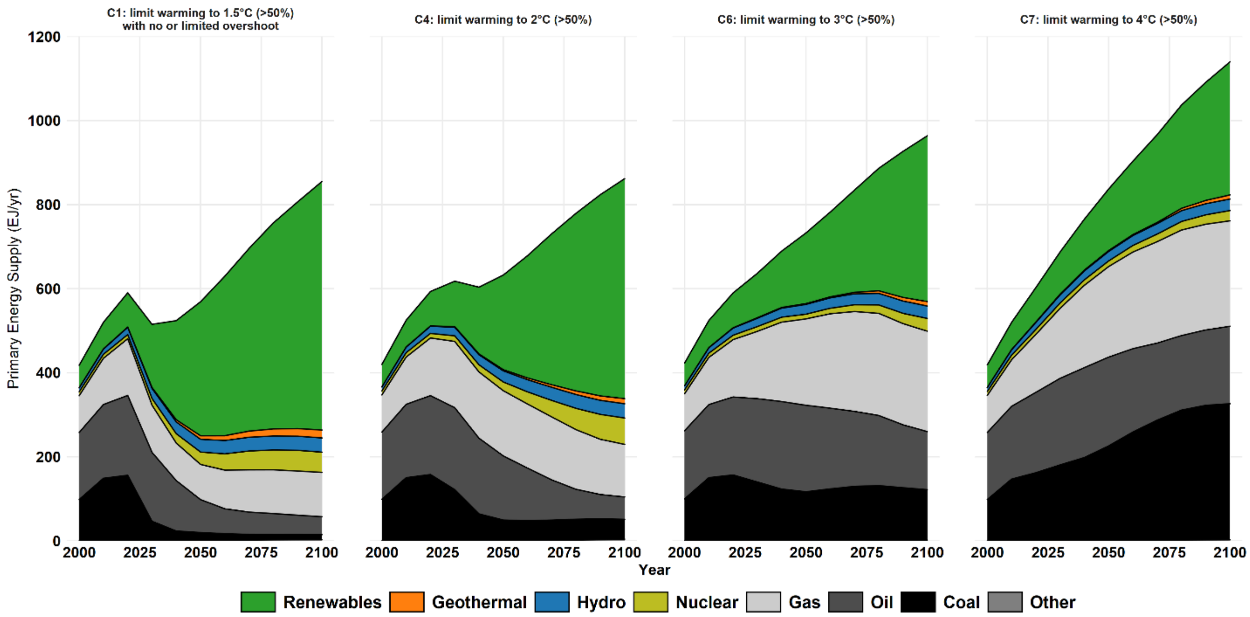

Figure 1: Median energy use predictions from (Byers et al., 2022) database by climate change mitigation outcome. Author's data processing and graphic.

While graphs like Figure 1 can take on the feeling of an abstract colouring exercise, they quickly become more real when the underlying policies and economic implications are considered. The policies to enable the low-carbon transition in the two leftmost panels are much more stringent than the policies which will allow the more emissions-intensive transitions in the rightmost panel to obtain.

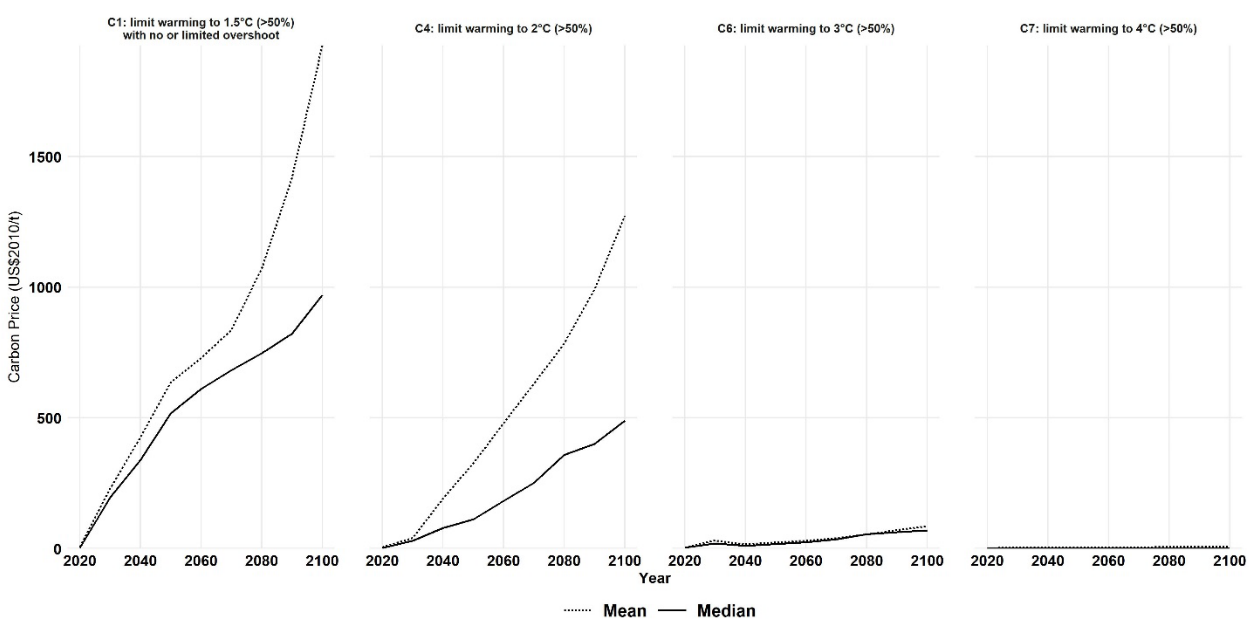

Figure 2: Mean and median carbon prices from (Byers et al., 2022) database by climate change mitigation outcome. Author's data processing and graphic.

One proxy for the stringency of policies is the implied price on carbon emissions, although many other factors can influence the transition to a cleaner economy. The Byers et al. database includes measures of carbon prices in each of the model runs and, as shown below, the mean and median carbon prices are substantially increased in the more stringent scenarios. The increased policy stringency, whether directly applied through carbon prices, or indirectly through regulation, that will be required to achieve aggressive climate change goals is often poorly understood.

The same rationale applies in Canada, where we have a long history of committing to targets without plans or willingness to meet them. After signing the Kyoto Protocol, for example, Canada embarked on a series of studies, consultations, and economic modeling to assess the policies required to meet our new commitments (Simpson et al., 2011, p. 68). While the conclusions of these studies showed that policies equivalent in stringency to carbon taxes of $50 to $150 per tonne of CO_2 would be required, no such policies were ever implemented. Instead, government assured industry that prices would not exceed $15 per tonne, a promise that would live on for more than a decade (Simpson et al., 2011, p. 96). Canada has committed again and again to global targets, at UNFCCC meetings in Kyoto, Copenhagen, Paris, and Glasgow, often with little to no link between our commitments to targets and commitments to enact policies to meet them. And, predictably, we have failed to meet every single one of those targets.

As of this writing, Canada's suite of GHG mitigation policies is the most stringent ever enacted in this country: federal carbon pricing via the *Greenhouse Gas Pollution Pricing Act*, clean fuel standards, limits on the emissions intensity from coal and natural gas electricity generation, emissions performance regulations for vehicles, and myriad fiscal incentives for emissions reductions complement initiatives in all of Canada's largest and most emissions-intensive provinces. Still, the most recent federal government projections see us missing our recent commitments by almost 200Mt CO_2e/yr by 2030, as shown in Figure 3.

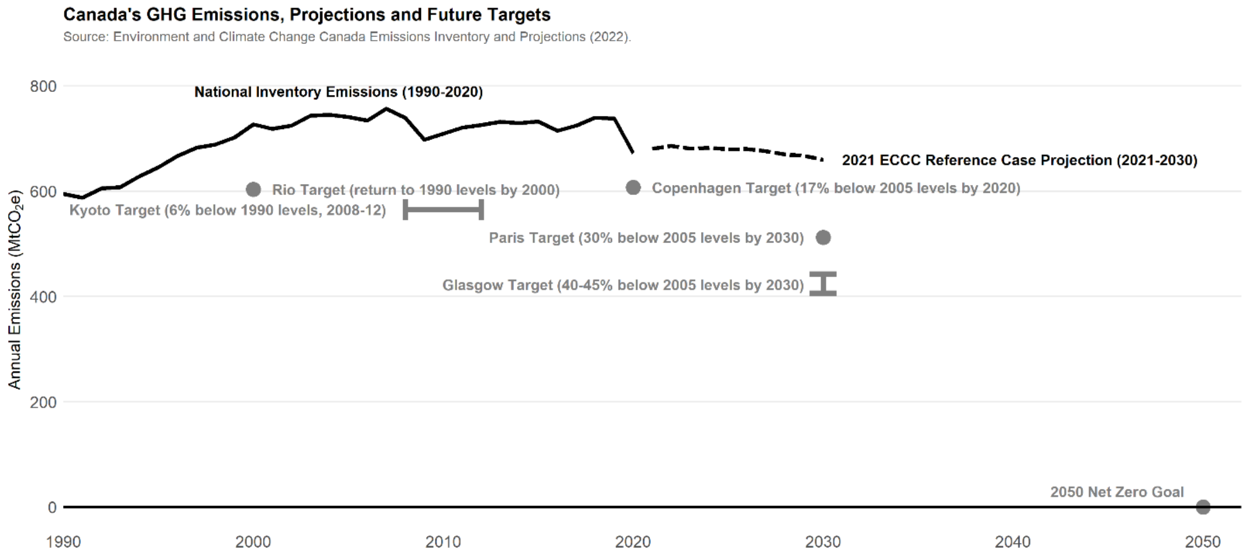

Figure 3: Canada's emissions and our international commitments. Author's figure, Canadian government data (Environment and Climate Change Canada, 2021; Government of Canada, 2021).

While the stringency of Canadian carbon pricing policies and other complementary measures has increased, Canada's international commitments remain out-of-step with the expected impacts of the measures enacted so far. An on-going failure to link the two will likely see Canada miss another set of commitments or need to close a substantial emissions gap through the purchase of international emissions credits.[1] In the sections which follow, I discuss attributes of Canada's current emissions policies, with a focus on emissions pricing, which may affect the likelihood of meeting our national goals.

Investment certainty under carbon pricing: mitigation in the oil sands sector

Since carbon pricing was established in Canada, a frequent refrain from both industry and think-tanks has been the need for cost certainty to underpin investments (Beugin and Shaffer, 2021). In addition to a fixed carbon pricing schedule through 2030, other fiscal policy tools including investment tax credits have also been deployed to allow for more rapid returns to capital-intensive investments in abatement (Gorski and El-Aini, 2022, p. 3). And, in 2022, the Government of Canada announced that it would create a Canada Growth Fund which would underpin measures such as the carbon contracts for differences proposed by Beugin and Shaffer in order to "ensures businesses can plan long-term investments in decarbonization and clean technologies based on a predictable price on carbon pollution and carbon credits" (Government

[1] Canada ended up facing this trade-off with respect to meetings its Kyoto commitments (Simpson et al., 2011, p. 107). The government of Stephen Harper chose to withdraw from the Kyoto Protocol which precluded any further international requirements to reduce emissions or obtain credits from other countries or international projects. See U.N. Depositary Notification [C.N.796.2011.TREATIES-1 dated 16 December 2011](#).
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of Canada (Ministry of Finance), 2022, p. 30). This section examines the importance of carbon pricing certainty to some types of investments, while highlighting the interaction of these measures with other aspects of carbon pricing programs and some confounding potential pitfalls.

Canada's oil and gas sector, and its oil sands sector in particular, are the epitome of an emissions-intensive and trade-exposed (EITE) sector. The production (or upstream) part of the industry sells into a global market with regional prices derived from international benchmarks, net of transportation costs to or from tidewater. For example, the plant-gate price of heavy crude oil in Alberta will generally reflect the price of a similar barrel on the Texas gulf coast, net of transportation costs, although sometimes transportation system bottlenecks lead to much larger basis differentials. Traditionally, oil in the US mid-continent reflected Gulf Coast pricing plus a transportation cost adder, reflecting the fact that the marginal barrels into that market were shipped into the area from the Gulf Coast. This pricing relationship means that, when domestic policies are applied to the production of oil, there is limited to no opportunity to pass those costs through to consumers if similar policies are not applied in other jurisdictions. It also means that there is substantial volatility in the potential investment returns from oil sands projects before we even consider the return on investments in emissions abatement. The industry has also been lobbying intensively for support for a multi-billion dollar investment in abatement capital (Oil Sands Pathways to Net Zero Initiative, 2021).

Historically, when it comes to carbon pricing and the oil sands, the questions that have been most pertinent to ask are 1) will the carbon pricing system reward design changes that lower emissions and/or ongoing improvements in emissions or emissions intensity (see Leach, 2012); 2) will the carbon pricing system affect investment and eventual production(Bošković and Leach, 2020; Leach and Boskovic, 2014); and 3) how will changes in global oil markets and climate change policies alter the oil sands investment thesis (Chan et al., 2012; Leach, 2022). Given the changes that have taken place in the industry over the past 5-7 years, the first and second questions are less relevant, as limited new project investment is forecast for the oil sands, replaced by *brownfield* expansions of existing sites (IHS Markit, 2022). As a result, the key question for carbon pricing policies is whether they can, in fact, provide sufficient incentives for material improvements in existing operations.

To assess the value of carbon price certainty, I use a model of an existing oil sands project to support two key points on the potential effectiveness of carbon pricing policies to lower emissions in capital-intensive industries. First, I highlight the degree to which investment certainty is crucial to policy effectiveness. Second, I show how other policy design elements, in particular the output-based allocation of emissions credits, interacts with policies meant to provide investment certainty. The evidence suggests that the time structure of both investments and returns may lead to less investment than would otherwise be the case, and therefore less improvement in emissions-intensities, unless the returns to abatement can be locked-in over decades through tax or other financial measures.

Consider an oil sands mine with 40 years of production life remaining, comparable to either the Imperial Oil Kearl project or the Suncor Fort Hills project. Projects like these are financially viable in a forward-looking analysis, at least under current third-party forward-looking forecasts used for reserve evaluation, but may or may not recover all of its initial capital investment.[2] For example, future free cash flow from the Kearl oil sands mine assuming a 40-year remaining production horizon, would have to average $17.90 per barrel to recover the balance of its initial capital investment with a return equivalent to current long-term bonds, or $39.10 per barrel to realize a 10% rate of return on current unrecovered capital balances. Numbers for Fort Hills are similar, at $15.61 per barrel for a return on current unrecovered capital equal to the current long term bond rate, or $34.08 per barrel to meet a 10% rate of return on that balance. These returns are not out-of-the-question as, for example, the pre-tax net revenue for Kearl in 2021 was $22.19 per barrel, and 2022 revenues promise to be substantially higher, but such capital recovery is by no means guaranteed.

Using the model from Bošković and Leach (2020), I construct a forward-looking discounted cash flow model of an oil sands mine with 194,000 barrels per day of capacity and a remaining mine life of 40 years, comparable to the Fort Hills project. As shown in Table 1, my model finds that the project is financially viable under the Sproule (2022) price forecast used to set the baseline, and its forward-looking net-present value is sufficient to recover the majority, although not all, of the initial unrecovered capital costs of the mine. The project, at least in this forward-looking analysis, is also relatively resilient to oil price changes, with the project earning positive forward-looking net-present value so long as real-dollar West-Texas Intermediate (WTI) oil prices are above US$45.16 per barrel.

Under the Alberta's *Technology Innovation Emissions Reduction Regulation* (*TIER*, 2019), the average costs of emissions is very low ($0.47 per barrel), and so large changes in the carbon price will not materially change the forward-looking financial performance of the project. This is because the *TIER* regime includes both carbon prices and output-based allocations of emissions credits which act to reduce average compliance costs. If the project were, instead, to be covered by a carbon tax with no offsetting allocation of credits, the average cost of emissions compliance would be $4.17 per barrel, and the net present value of the project would be reduced by $2 billion. Importantly, *TIER* reduces the average cost of compliance while maintaining incentives to reduce emissions intensity: for example, an emissions-intensity reduction of 20% for the

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[2] Both the Kearl and Fort Hills oil sands projects have substantial unrecovered initial capital costs as measured through Alberta's royalty regime. As of the end of 2021, Kearl listed an unrecovered initial capital investment of $30.7 billion while Fort Hills listed an unrecovered balance of $23.6 billion.

project would lead to average revenues from the *TIER* regime of \$0.34 per barrel and increase project net present values by over half a billion dollars – an average return per tonne abated equivalent to the real dollar value of the federal benchmark carbon price schedule.

Table 1: Oil sands project baseline characteristics under Sproule (2022) pricing assumptions.

Key commodity price assumptions (\$2022)*		
WTI Crude Oil at Cushing, OK	\$US/bbl	76.09
WCS Heavy Crude at Hardisty, AB	\$US/bbl	63.66
Bitumen value at site	\$CA/bbl	70.60
AECO/NIT Natural Gas	\$CA/GJ	3.54
\$CA/\$US	\$CA	1.25
Average revenues and costs (\$CA2022 per barrel bitumen)		
Bitumen revenue	\$/bbl	70.93
Capital and operating costs	\$/bbl	30.62
GHG compliance and abatement costs	\$/bbl	0.47
Royalties and Taxes	\$/bbl	19.86
Free Cash Flow	\$/bbl	19.97
Forward-looking financial metrics		
Net Present Value (10% discount rate, or NPV_{10})	2022 CA\$ (millions)	22,213
Break-even WTI oil price (NPV_{10}=0)	2022 CA\$ per barrel	45.16
Initial conditions		
Accumulated site reclamation liabilities	2022 CA\$ (millions)	3,000
Unrecovered initial capital costs	2022 CA\$ (millions)	23,000

* commodity prices from Sproule (October, 2022) escalated price forecast.

For more detailed analysis of the sensitivity to carbon pricing parameters, consider the following sequence of results. First, with a carbon tax alone and no offsetting credit allocations, the net present value of the project is increasing in oil prices (down each column) and decreasing in the carbon price (across each row).

Table 2: Carbon and oil price sensitivity for a pure carbon tax.

Carbon price (real \$/tonne)		30	60	90	120	150	*TIER* at *GGPPA* price schedule
WTI oil price (real \$/bbl)	30	(20.06)	(21.09)	(22.12)	(23.16)	(24.19)	(19.45)
	60	10.88	10.17	9.46	8.73	7.99	11.30
	90	28.09	27.55	27.00	26.45	25.89	28.45
	120	44.51	44.00	43.49	42.98	42.46	44.83
	150	60.68	60.18	59.68	59.14	58.63	60.98
	180	76.63	76.13	75.64	75.15	74.66	76.92

Adding an output-based allocation of emissions credits at a fixed rate improves the financial performance of the project at all carbon and oil price combinations, as the value of the credits is increasing across each row. Because the credits alter the long-term profitability of the project, they also change the average royalty and tax rates applied to the project, and so the value of the credits at any given carbon price (down each row) is not constant (see Government of Alberta, 2020). For example, at a $120/tonne carbon price, the output-based allocations of emissions credits increase project value by $3.8 billion in the lowest ($30/barrel) oil price case relative to a pure carbon tax, but only by $1.8-1.9 billion as oil prices range from $120-$180 per barrel. So, the output-based allocations improve both the overall financial viability of the project and reduce the project's sensitivity to low oil prices.

Table 3: Carbon and oil price sensitivity with output-based allocations of emissions credits according to the *TIER*/*GGPPA* schedule.

Carbon price (real $/tonne)		30	60	90	120	150	*TIER* at *GGPPA* price schedule
WTI oil price (real $/bbl)	30	(19.11)	(19.20)	(19.29)	(19.37)	(19.46)	(19.45)
	60	11.52	11.46	11.40	11.35	11.29	11.30
	90	28.61	28.57	28.52	28.48	28.44	28.45
	120	44.98	44.94	44.90	44.86	44.82	44.83
	150	61.13	61.09	61.05	61.01	60.97	60.98
	180	77.08	77.04	77.00	76.96	76.92	76.92

Carbon prices are intended to spur investments in emissions reduction technologies. The purpose of this section is not to fully analyze different options but rather to demonstrate how policy parameters (carbon prices and output-based allocations) and policy certainty combine to influence the viability of emissions-reducing investments. Many of the potential emissions reductions available to oil sands facilities come with significant capital and operating costs. For example, technologies such as carbon capture and sequestration (CCS) or small modular nuclear reactors (SMNRs) both offer potential oil sands applications, but with substantial up-front capital costs. For this particular experiment, we use a hypothetical investment which reduces emissions by 80% while maintaining production. We examine cases where this investment manifests as either an increase in capital costs, operating costs, or both, and provides a 10% return on the incremental investment (i.e. it does not change the net present value of the project itself) under the current carbon pricing regime including the output-based allocation of credits. We assume that the technology is such that operating costs are uncommitted, and so the facility can (and does) revert to pre-investment operating conditions if the carbon price is removed.

Table 4 shows the impact of removing of carbon pricing policies before the end of the mine life on project net present values under different abatement commitment scenarios. In the first column, where no abatement investment is made, the project proponent is always made better off with the removal of carbon pricing because carbon pricing is, in and of itself, costly to the project. If substantial abatement capital expenses are deployed, this changes dramatically, as shown in the rightmost two columns. The investment in abatement capital represents a long-term bet on future emissions pricing and, insofar as those prices are no longer present, the capital invested doesn't earn a return and erodes the overall value of the mine. Another way to think about this is that the proponent of the mine, having made a major investment in abatement, gains from the carbon pricing policy remaining in place. Capital-intensive abatement investments create support for continuing the policy itself and so the returns to abatement investments are self-fulfilling. This result, however, is not universal.

Table 4: Change in project NPV across different emissions abatement scenarios and carbon policy duration values for a *TIER*-style policy with output-based allocations of emissions credits.

		Change in project NPV vs. Inaction ($ millions)			
Expenditure share		**No abatement expenditure ("Just pay the tax")**	**100% uncommitted operating expenditures**	**50% capital, 50% uncommitted operating expenditures**	**100% capital expenditures**
Carbon policy duration (zero beyond year X)	**5**	193	225	-417	-1,058
	10	119	175	-222	-617
	15	69	162	-95	-351
	20	37	125	-37	-198
	25	16	83	-14	-110
	30	5	48	-4	-56
	35	1	20	-1	-21

Table 5 Change in project NPV across different emissions abatement scenarios and carbon policy duration values for a pure carbon tax without output-based allocations.

		Change in project NPV vs. Inaction ($ millions)			
Expenditure share		No abatement expenditure ("Just pay the tax")	100% uncommitted operating expenditures	50% capital, 50% uncommitted operating expenditures	100% capital expenditures
Carbon policy duration (zero beyond year X)	**5**	1,590	1,621	985	334
	10	919	979	593	199
	15	525	622	374	120
	20	293	385	233	73
	25	157	228	141	46
	30	76	122	80	30
	35	28	52	40	20

In particular, this result is not robust to a pure carbon tax, at least in the scenarios considered in this hypothetical example. Where the policy does not feature offsetting emissions credits, the proponent is always better off if the carbon price is cancelled before the end of mine-life, as shown in Table 3. The change in project net present value is smaller if the abatement expenditure is more capital-intensive, and also lower as the abatement is more effective, but for the example considered in this analysis, the effect of early carbon pricing cancellation is always positive. Even having made the investment in abatement, the project proponent would still prefer to see emissions pricing removed, all else equal.

The oil sands project case demonstrates two important attributes of effective carbon pricing beyond the fact that it creates incentives for ongoing improvement: the importance of policy permanence, and the interaction between the average cost of carbon policy and the gains from policy permanence that serve to enhance carbon pricing lock-in.

There is one additional factor to consider here – the double-edged sword of emissions price certainty. A major source of emissions growth in Canada has been the emissions tied to increasing oil production, much of which has come from large, emissions-intensive projects in the oil sands. And, in this case, emissions price (and broader emissions policy) certainty cuts in a different direction, as reductions in policy risk and policies to lower average costs will make oil sands investments more viable, all else equal. The output-based allocations reduce the break-even oil price required to ensure the mine's viability by over US$3.50 per barrel compared to a pure carbon tax.

Carbon Pricing in the Electricity Sector: the importance of technology neutrality

The degree to which a carbon pricing system can provide the incentive for the adoption of substitutes is extremely important to driving emissions reductions, in particular with so-called output-based pricing systems. These systems, while designed to reduce the average cost of carbon emissions in a particular industrial sector, can also mute the incentives for substitution within a sector.

To see how output-based pricing systems can either amplify or mute differences between technologies, consider the electricity sector implementation of *TIER* in Alberta compared to the federal *GGPPA* backstop. Under *TIER,* all electricity generating facilities receive the same output-based allocation of emissions credits, at a rate of 0.37t/MWh. The federal *GGPPA* allocates credits only to different sources at different rates. Under regulations for the *GGPPA,* coal-fired electricity receives allocations at a decreasing rate starting at 0.8t/MWh in 2019, decreasing to 0.37t/MWh in 2030 and beyond while gas generators in service at the time the regulation receive an allocation of 0.37t/MWh in each year. New gas generating units coming on-line after January 1, 2021 receive declining allocations of emissions credits beginning at a rate of 0.37t/MWh in 2021 and declining to 0t/MWh for years 2030 and beyond. Renewable and other emissions-free generation receives no statutory allocation of emissions credits under the *GGPPA*, although some newer facilities that began operation after January 1, 2017 may be able to qualify for the federal offset regime in future years.

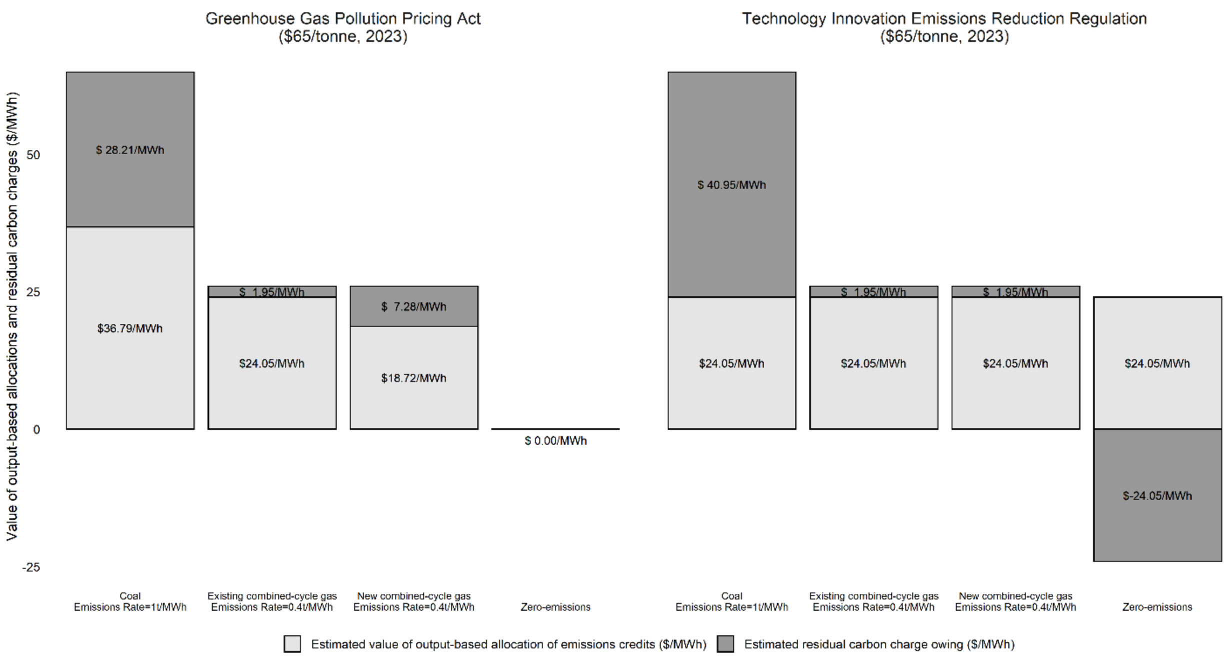

Figure 4: Output-based allocation values and net carbon pricing costs by generation technology under the Alberta *TIER* regulation and the federal *GGPPA* backstop.

As shown in Figure 1, the Alberta *TIER* regulation (right panel) provides a substantial advantage between generation sources which preserves the substitution incentives of a pure carbon tax. For example, a pure carbon tax of $65/tonne would increase the costs of the coal plant illustrated in the figure by $65/MWh (1t/MWh * $65/tonne), while increasing the costs of the gas plant by $26/MWh (0.4t/MWh * $65/tonne), a difference of $39/MWh. The *TIER* implementation provides a net carbon cost to the coal generator of $40.95/MWh versus $1.95 to the natural gas plant, preserving the difference in costs of $39/MWh that would be present with a pure carbon tax. By contrast, the federal *GGPPA* (left panel) offers a cost advantage to natural gas power plants of only $26.26/MWh (for existing gas plants) and $20.93/MWh (for newer plants), a much smaller incentive for substitution than provided by either a pure carbon tax or by Alberta's regulation.

The same relationship holds for emissions-free generation versus, for example, an existing combined-cycle natural gas plant. Under *TIER,* emissions-free generation sources such as wind and solar power, but also prospective nuclear generation, would benefit from the allocation of emissions credits at the same rate as other sources of generation, providing an effective advantage over emissions-intensive competitors equal to the full value of the carbon price. For example, a wind generator operating today receives $24.05/MWh of net benefit from the carbon pricing policies under *TIER*, while a natural gas power plant pays, on net, $1.95/MWh. The difference, $26/MWh, is equal to the difference in their respective emissions intensities (0.4t/MWh) times the carbon price ($65/tonne). In fact, under Alberta's offset protocol, emissions-free generation may qualify for an even larger allocation of emissions credits (0.52t/MWh) under the province's offset protocol, which would confer a carbon cost advantage of $35.75/MWh over a natural gas power plant. That cost advantage is the equivalent of what would be present under a $89.37/tonne carbon tax.

Compare this with the treatment of existing and (so far) new generation under the federal *GGPPA* in the left panel of Figure 1. New or existing emissions-free generation receives no credit allocations under the federal backstop, and so the policy serves to substantially narrow the cost advantage provided to lower-emissions technologies relative to what would be provided under a pure carbon tax. The carbon-price-induced cost advantage for renewables over gas power under the *GGPPA* is only $1.95/MWh for existing plants or $7.28/MWh for new gas plants, equivalent to the advantage that would be provided by carbon taxes of $4.88/tonne and $18.40/tonne respectively.

This section highlights the importance of sector-level distortions in carbon pricing, as the *GGPPA* offers a larger effective output subsidy to higher-emitting sources of generation. Where these effective subsidies are in place, we should not expect to see large changes in the composition of output within sectors as would be the case with a pure carbon tax.

Carbon pricing isn't (always) about making things more expensive

Appropriately designed carbon pricing policies don't necessarily make energy more expensive, and certainly need not increase the average cost of energy procurement. Consider two energy technologies crucial to a low-carbon transition: hydrogen and renewable power.

Hydrogen is one of the key energy carriers in many global decarbonization scenarios. The International Energy Agency (IEA, 2021) net-zero scenario projects that hydrogen will account for 6% of energy demand by 2050, which would require a five-fold increase over current production, and a massive scale-up in clean-hydrogen production. Currently, 99% of hydrogen is produced from unabated fossil fuels, and in Canada that is generally through steam-methane reforming using fossil methane (natural gas) as a feedstock. Hydrogen is used today in oil refining, heavy-oil upgrading, and fertilizer and petrochemical production and, with appropriately-designed carbon pricing policies, lower emissions hydrogen pathways could end up cheaper than current high-emissions alternatives. In research recently presented to the Global Conference on Environmental Taxation, jointly-authored with University of Alberta MBA student Mark Droessler, we look at the costs of *blue* (fossil-derived but with carbon capture and storage) vs *grey* (fossil-derived with no carbon capture) hydrogen. We find that, in the absence of carbon pricing policies and other fiscal measures, the levelized cost of new *grey hydrogen* production is cheaper ($1.62/kg vs $2.36/kg) than *blue hydrogen*, but that this relationship can be reversed in the presence of carbon pricing policies already in place in Alberta and Canadian fiscal policies. We find that these policies lower the cost of *blue hydrogen* by nearly half, to $1.23 per kg, while increasing the cost of *grey* hydrogen to $2.01 per kg. Importantly, these policies interact such that the variable costs of *grey* hydrogen production are also likely to be more expensive than the costs of new or retrofitted *blue* hydrogen production, thereby encouraging substitution and on-going improvement.

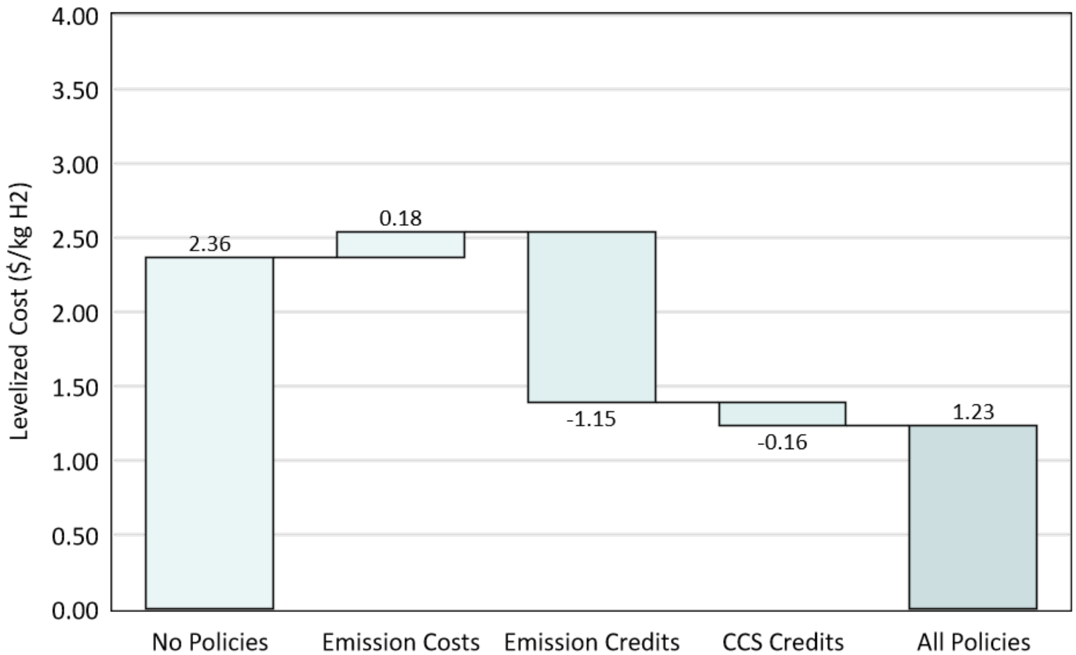

Figure 5: Carbon pricing and fiscal policy impact on *blue* hydrogen production costs. Source: Droessler and Leach (2022), used with permission, to be updated for final version.

Renewable power can be affected by carbon pricing and other fiscal policies in much the same way as *blue hydrogen*. For example, as discussed above, output-based allocation of emissions credits, for example as included in the *TIER* Regulation in Alberta, may reduce the cost of renewable power well below their pure financial costs. These impacts may be exacerbated by production tax credits, investment tax credits, accelerated capital cost allowance regimes, along with renewable portfolio standards or offset protocols which offer higher values for a project's renewable energy attributes than the carbon pricing system alone.

Consider, for example, that current estimates of the levelized, unsubsidized cost of wind generation is $US26-US$50 ($25-$66) per MWh (Lazard, 2021), while the *TIER* regulation in Alberta provides, as of 2023, output-based allocations of emissions credits worth $24/MWh, and the offset protocol provides an even more generous option of $33.80/MWh over-and-above electricity revenues and any reputation value that companies derive from the construction of low-emissions projects. The ability to secure a second, perhaps even more valuable revenue stream from carbon pricing means that, all else equal, more renewable supply will be built and come online at prices far below what would normally be required to finance merchant renewable power.

In both cases of renewable power and *blue* hydrogen, the net cost of production when carbon pricing revenues and other fiscal policies are accounted for is well below most if not all fossil-derived alternatives. That's not, of course, to say that this is a free lunch. In the case of an output-based pricing system, the credits have value only insofar as other emissions are priced and so there are new costs that are being created in the system, they are just not borne by renewable sources.

Conclusions

It's tempting to look at Canadian data, or in some cases provincial data, and conclude that increasing or stable emissions indicate that carbon pricing isn't *working* to reduce emissions. Carbon pricing is influencing decisions, investments, and substitution at the margin, but perhaps not enough to drive aggregate emissions down. However, when we examine individual sectors and the investments made to reduce emissions, we can see a lot of evidence of policies reducing emissions well below where they would otherwise be. This, in and of itself, is not sufficient to ensure that emissions will fall by enough to meet Canada's pledges on the international stage, or in a manner consistent with global climate change goals. In fact, current projections suggest that we will not meet our projections without significantly more stringent policies.

This paper has offered an analysis of three key considerations with respect to carbon pricing policies: the degree to which they assure returns to capital-intensive investments in abatement, the degree to which they reward within-sector substitution to lower-emissions sources, and the degree to which they make lower-emissions alternatives cheaper in absolute terms, not simply in relative terms.

When evaluating policies, it's also important to keep in mind that all emissions pricing policies are not created equal, and that policies are not assigned randomly. The fact that Alberta, for example, has relied on policies with substantial output-based allocations of tax credits to emissions-intensive and trade-exposed sectors is not accidental – it's a function of the importance of emissions-intensive and trade-exposed sectors to the economy.[3] And, these policies imply an expectation that emissions-intensive production will continue, albeit hopefully with fewer emissions per unit of production over time. Policies are chosen with specific consequences in mind, and so we are generally not offered the type of experimental design that we might otherwise prefer for analysis of this type. As a result, all is not equal – when we are comparing the outcomes of carbon pricing policies in different jurisdictions, other factors including but not limited to economic growth, foreign direct investment, other environmental and fiscal policies, local energy and labour markets, and sunk capital including building and vehicle stocks affect the choice of policy and the impact of different policy choices. We would not expect that the same carbon pricing policy applied across all sectors and provinces to yield the

[3] Alberta has had three major carbon pricing policies since 2007, beginning with the *Specified Gas Emitters Regulation* (*SGER*, 2007). This policy was replaced, in 2018, with the *Carbon Competitiveness Incentive Regulation* (*CCIR*, 2017). The *CCIR* was, in turn, replaced by the *Technology Innovation and Emissions Reduction* (*TIER*, 2019) *Regulation*.

same results in each instance. We should not, therefore, but surprised that there is divergence in outcomes where different policies are applied across sectors and provinces.

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