Ideas for a More Prosperous Society

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THE CUMULATIVE IMPACT OF HARMFUL POLICIES

THE CASE OF OIL AND GAS IN ALBERTA

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HIGHLIGHTS

According to the International Energy Agency, the global demand for hydrocarbons is expected to keep increasing at least until 2040. Yet in Canada, during the past year or so, an unusually large number of major events—essentially all negative—affected the oil and gas industry. The departure of international companies, pipeline project delays, and unprecedented discounts on Western Canadian Select (WCS) are just some of the signs that the country's oil and gas sector is facing serious challenges.

Chapter 1 – Market Access

- Lack of pipelines is the issue currently having the greatest financial impact on the oil and gas industry, over other factors, and affects not only the industry, but also provincial finances and the whole Canadian economy.
- During the 2009-2012 period, when there were no evident pipeline constraints, WCS (the commonly used benchmark for Canadian oil) traded on average at a US$11.17 discount to WTI (the U.S. oil benchmark).
- In 2018, the WCS vs. WTI discount peaked at US$50 per barrel, which led the Alberta government to impose production cutbacks of 325,000 barrels per day, temporarily easing the pain, but not solving the underlying problem.
- A report published by RBC in May 2018 found that the cost of a sustained US$5/barrel larger-than-normal WCS-WTI price gap would be about C$4 billion to C$5 billion a year.
- In 2018, for the first time, output exceeded pipeline capacity, and crude oil exports by rail exceeded 300,000 barrels per day by the end of the year, up from around 150,000 at the beginning of the year.
- Transportation by rail may alleviate the problem, but it is not cheap: Moving oil by train to the U.S. Gulf Coast costs an extra 50% to 100% compared to moving it by pipeline.
- Except for the lack of pipelines, there is no reason anymore for WCS to trade at a discount to WTI, since the U.S. is awash with very light oils from fracking and needs our heavier oils.
- Improved access to tidewater would allow Canadian producers to service Asia, whose demand for oil is expected to increase by 9 million barrels per day by 2040, along with major increases in demand for natural gas.
- Lack of pipelines also increases the cost of crude oil for Eastern Canadian refineries, with Canada importing approximately 670,000 barrels of crude oil per day in 2017, around half of which came from overseas.

Chapter 2 – Carbon Taxes

- There are no valid reasons that justify a carbon tax being 50% higher than the de facto rate currently in effect in Quebec's cap & trade system, as Alberta's $30 carbon tax is—and even less to justify it being about twice as high as in Quebec, as the federal tax will be by 2022.
- The carbon tax regimes now in force across Canada ignore a few realities: a) that carbon emissions are first and foremost a consumption problem; b) that while companies don't vote, they may move to another jurisdiction (i.e., carbon leakage); and c) that Canada is a trading nation and does not live in isolation.
- Alberta and Saskatchewan produce more carbon than they consume, and are therefore penalized by Canada's production-based carbon taxes; B.C., Ontario, and Quebec all consume more carbon than they produce, and are thus favoured by Canada's methodology.
- It is pointless to shut down a CO_2 emitting facility if the goods it produces are to be later imported or produced in another jurisdiction which does not have as strict pollution-control measures.
- A strong argument against carbon border taxes is that they impinge upon free trade; a unilateral border-adjustment system could create a backlash, and might even lead to a trade war with our trading partners.
- Any carbon tax should be compensated by an equivalent reduction of other taxes, preferably the ones that are the most destructive in economic terms: corporate taxes on profits and personal income taxes, for example.
- Governments may not want to forego the carbon tax proceeds, but a tonne of CO_2 not emitted in

Canada or elsewhere in the world has the same impact on the climate. The purpose of a carbon tax should be to reduce carbon emissions, not to raise tax revenues from individuals and companies.

- Allowing emitters to use all the tools available to them to achieve the stated goal, at the lowest possible cost, would reduce the adverse economic impact on the Canadian economy.

Chapter 3 – Regulations and Permitting Delays

- Companies operating in Alberta point to the permitting delays observed in the province as a serious problem; compared to oil and gas producing American states, the province is not competitive in this regard.
- When applying to drill on U.S. freehold land, permitting is always months faster than it is in Alberta, with Texas being the friendliest state.
- Between 2014 and 2017, requests by stakeholders to be heard before a project is approved have doubled in relative terms, while the total numbers of applications for both wells and facilities fell by over 40%.
- The pitfalls of social licence, by giving too much room to various groups, seem to have affected applications for facilities and wells, and are likely to be fuelling a loss of confidence in the existing process due to its unpredictability.
- Extraordinary timelines also affect oil sands projects, with a typical in situ development in Alberta having a best-case approval timeline from the start of consultation through to the start of construction of 4 to 6 years.

Chapter 4 – Energy Corridors and First Nations Partnerships

- An early example of an energy corridor was proposed in the 1970s from the Mackenzie River delta to Alberta and the United States. Revived in the early 2000s, it was later cancelled following the price drop for natural gas.
- The presence of First Nations in the development of energy resources and energy corridors is now a fact of life, with the Indian Resource Council (IRC) now representing over 200 First Nations across the country.
- Some of the main opposition to Bill C-48, the Oil Tanker Moratorium, is coming from First Nations-led groups promoting their own pipeline project, while the IRC is asking the federal government to put Bill C-69 on hold.
- Two current examples of potential energy corridors are the corridor where the Eagle Spirit pipeline would be located, between Alberta and the BC coast, and the corridor where the Ontario-to-Quebec Gazoduq pipeline would be located.

Chapter 5 – Other Issues

- Methane is a much more potent greenhouse gas than carbon dioxide. Alberta and British Columbia—the main gas producing provinces—are committed to reducing methane emissions by 45% by 2025.
- From its inception early in 2017, the proposed Federal Clean Fuel Standard has been identified as duplicating existing provincial and federal emission reduction policies. It is essentially another carbon tax under different name.
- Some research has shown that implementing renewable fuel standards led to an increase in food prices and a smaller reduction in global GHG emissions compared to other policy options.
- There are over 120,000 inactive oil and gas wells in Western Canada, around three quarters of which are in Alberta and the remainder mainly in Saskatchewan, but also in British Columbia.
- Reclaiming a well requires returning the surface land to its original state. Orphan wells are wells whose owners were unable or unwilling to plug the borehole and/or reclaim the site.

POINTS SAILLANTS

Selon l'Agence internationale de l'énergie, la demande mondiale d'hydrocarbures devrait continuer à croître au moins jusqu'en 2040. Pourtant, au Canada, depuis un an environ, un nombre inhabituellement élevé d'événements majeurs – tous essentiellement défavorables – ont perturbé l'industrie pétrolière et gazière. Le départ d'entreprises internationales, les retards des projets de pipeline et les escomptes sans précédent consentis sur le Western Canadian Select (WCS) ne sont que quelques-uns des signes indiquant que le secteur pétrolier et gazier du pays fait face à de graves défis.

Chapitre 1 – Accès au marché

- La pénurie de pipelines est, avant d'autres facteurs, celui qui produit actuellement le plus grand impact financier dans l'industrie pétrolière et gazière; cette pénurie nuit non seulement à l'industrie, mais aussi aux finances publiques des provinces et à l'ensemble de l'économie canadienne.

- Durant la période 2009-2012, alors que les pipelines ne faisaient l'objet d'aucune contrainte notoire, le WCS (couramment utilisé comme référence du pétrole canadien) se négociait, en moyenne, avec un escompte de 11,17 $US par rapport au WTI (le brut de référence aux États-Unis).

- En 2018, l'escompte sur le WCS par rapport au WTI a atteint un sommet de 50 $US le baril, ce qui a poussé le gouvernement albertain à imposer des coupes de 325 000 barils par jour dans la production, atténuant temporairement la crise, mais ne réglant pas le problème sous-jacent.

- Selon un rapport publié en mai 2018 par la Banque Royale du Canada, le coût pour l'économie canadienne d'un écart de prix persistant de 5 $US le baril au-dessus de l'écart normal entre le WCS et le WTI serait d'environ 4 à 5 milliards $CAN annuellement.

- En 2018, pour la première fois, la production a excédé la capacité des pipelines; les exportations de brut par rail ont dépassé 300 000 barils par jour en décembre, alors qu'elles étaient d'environ 150 000 barils onze mois plus tôt.

- Le transport ferroviaire peut atténuer le problème, mais il est dispendieux : le transport du brut par train jusqu'à la côte américaine du golfe du Mexique coûte 50 à 100 % de plus que par pipeline.

- Outre la pénurie de pipelines, il n'y a plus aucune raison justifiant l'escompte sur le prix du WCS par rapport au WTI puisque les États-Unis font face à une surabondance de pétroles très légers obtenus par fracturation hydraulique et qu'ils ont besoin de nos pétroles plus lourds.

- Un meilleur accès aux côtes permettrait aux producteurs canadiens d'approvisionner l'Asie, où la demande de pétrole est censée augmenter de neuf millions de barils par jour d'ici 2040, et où la demande de gaz naturel augmentera fortement aussi.

- La pénurie de pipelines fait aussi augmenter le coût du brut pour les raffineries de l'Est canadien; le Canada a en effet importé près de 670 000 barils de brut par jour en 2017, dont près de la moitié provenait d'outre-mer.

Chapitre 2 – Taxes sur le carbone

- Aucune raison valable ne justifie qu'une taxe sur le carbone soit 50 % supérieure au taux *de facto* actuel du système de plafonnement et d'échange du Québec – comme c'est le cas de la taxe de 30 $ en Alberta – et encore moins qu'elle approche le double de celle du Québec, comme ce sera le cas de la taxe fédérale d'ici 2022.

- Les régimes de taxation du carbone actuellement en vigueur à travers le Canada ne tiennent pas compte de certaines réalités : a) que les émissions de carbone sont d'abord et avant tout un problème de consommation; b) que les entreprises, à défaut de voter, peuvent aller s'installer dans une autre entité territoriale (ce qui entraînera un transfert des émissions de carbone); et c) que le Canada est un pays commerçant et ne vit pas isolé.

- L'Alberta et la Saskatchewan produisent plus de carbone qu'elles n'en consomment et sont donc pénalisées par le fait que les taxes canadiennes sont basées sur la production; l'Ontario, la Colombie-Britannique et le Québec, qui consomment tous plus de carbone qu'ils n'en produisent, sont ainsi avantagés par la façon dont les taxes canadiennes ont été établies.

- Il est inutile de fermer des installations émettrices de CO_2 si les biens qu'elles produisent doivent ensuite être importés ou produits dans une autre entité territoriale où il n'y a pas de mesures antipollution aussi strictes.

- À l'imposition de taxes sur le carbone aux frontières, on peut opposer un solide argument selon lequel elles empiètent sur le libre-échange. Un système unilatéral d'ajustement à la frontière pourra provoquer une riposte et pourrait même mener à une guerre commerciale avec nos partenaires.

- Toute taxe sur le carbone devrait être compensée par une réduction équivalente d'autres taxes, préférablement celles qui sont les plus dommageables sur le plan économique : l'impôt sur les bénéfices des sociétés et celui sur le revenu des particuliers, par exemple.

- Les gouvernements ne voudront peut-être pas se priver du produit de la taxe sur le carbone, mais une tonne de CO_2 qui n'est émise ni au Canada ni ailleurs dans le monde aura le même impact sur le climat. L'objet d'une taxe sur le carbone devrait être de réduire les émissions de carbone et non d'augmenter les recettes fiscales versées par les particuliers et les entreprises.

- Permettre aux émetteurs d'utiliser tous les outils à leur disposition pour atteindre les cibles de réductions d'émissions de GES, au coût le plus bas possible, atténuerait l'impact économique négatif sur l'économie canadienne.

Chapitre 3 – Réglementation et retards dans l'attribution des permis

- Les entreprises qui font affaire en Alberta signalent que les retards constatés dans l'attribution des permis dans cette province sont un grave problème; à cet égard, l'Alberta ne soutient pas la comparaison avec les États américains producteurs de pétrole et de gaz.

- Lorsqu'une demande est présentée en vue d'effectuer des forages sur des terres franches aux États-Unis, les permis sont toujours délivrés plusieurs mois plus tôt qu'en Alberta, le Texas étant l'État le plus accommodant.

- Entre 2014 et 2017, la proportion des projets faisant l'objet de demandes d'auditions par des intervenants a doublé, pendant que le nombre total de projets visant des puits et des installations chutait de plus de 40 %.

- Les pièges de l'acceptabilité sociale, notamment ceux causés par la trop grande place accordée à divers groupes, semblent avoir nui aux demandes concernant des puits et installations et suscitent vraisemblablement une perte de confiance envers le processus actuel, qui est devenu imprévisible.

- Les projets d'exploitation des sables bitumineux font également l'objet de délais surréels : un projet typique de développement *in situ* en Alberta sera soumis, dans le meilleur des cas, à un échéancier d'approbation de 4 à 6 ans, du lancement des consultations jusqu'au début de la construction.

Chapitre 4 – Corridors énergétiques et partenariats avec les Premières Nations

- Un des premiers exemples de corridor énergétique a été celui proposé dans les années 1970 pour lier le delta du fleuve Mackenzie à l'Alberta et aux États-Unis. Ce projet, relancé au début des années 2000, a ensuite été annulé après la chute des cours du gaz naturel.

- La participation des Premières Nations dans le développement des ressources énergétiques et des corridors énergétiques est maintenant un fait établi, le Conseil des ressources indiennes (CRI) représentant aujourd'hui plus de 200 Premières Nations partout au pays.

- Certains des principaux opposants au projet de loi C-48 sur le moratoire relatif aux pétroliers sont en fait des groupes menés par des Premières Nations qui proposent leur propre projet de pipeline, tandis que le CRI demande au gouvernement fédéral de suspendre le projet de loi C-69.

- En guise d'exemples actuels de projets de transport d'énergie qui pourraient être réalisés, citons le corridor où serait aménagé le pipeline Eagle Spirit, entre l'Alberta et la côte de la Colombie-Britannique, et celui du pipeline Gazoduq, qui lierait l'Ontario au Québec.

Chapitre 5 – Autres enjeux

- Le méthane est un gaz à effet de serre beaucoup plus puissant que le dioxyde de carbone. L'Alberta et la Colombie-Britannique – les principales provinces productrices de gaz – se sont engagées à réduire leurs émissions de méthane de 45 % d'ici 2025.

- Depuis qu'a été lancé, au début de 2017, le projet de Norme sur les combustibles propres du gouvernement fédéral, on a constaté qu'il fait double emploi avec des politiques provinciales et fédérales actuelles de réduction des émissions. Il s'agit

- essentiellement d'une autre taxe sur le carbone sous un nom différent.

- D'après certains travaux de recherche, la mise en œuvre de normes sur les combustibles renouvelables a entraîné une hausse des prix des aliments et une réduction plus faible des émissions mondiales de GES en comparaison à d'autres politiques.

- On compte plus de 120 000 puits de pétrole et de gaz naturel inactifs dans l'Ouest canadien, dont près des trois quarts se trouvent en Alberta, et les autres principalement en Saskatchewan, mais aussi en Colombie-Britannique.

- Pour réhabiliter un puits, on doit remettre la surface du terrain dans son état original. Les puits orphelins sont ceux dont les propriétaires n'ont pu ou n'ont pas voulu boucher le trou de forage ou réhabiliter le site.

INTRODUCTION

In Canada, during the past year or so, an unusually large number of major events—essentially all negative—affected the oil and gas industry.

- **Capital flight:** In February 2019, Devon decided to divest from their Canadian operations.[1] This divestiture was preceded by the departure of international companies such as Royal Dutch Shell PLC, Total SA, Norway's state-owned Equinor ASA (formerly Statoil),[2] and of U.S.-based producers ConocoPhillips, Murphy Oil Corp., and Marathon Oil Corp.[3]

- **Pipeline delays:** Pipeline projects have been facing delay after delay: In August 2018, the Federal Court of Appeal squashed the proposed twinning of the Trans Mountain pipeline;[4] as recently as February 15, 2019, a U.S. judge denied a request for pre-construction work to go ahead on the Keystone XL pipeline;[5] and on Friday, March 1st, 2019, Enbridge announced that the replacement and expansion of its Line 3 linking Hardisty, Alberta to Superior, Wisconsin would be delayed by approximately one year.[6]

- **Oil prices:** During the third and fourth quarters of 2018, the Western Canadian Select (WCS) discount to West Texas Intermediary (WTI), the U.S. oil benchmark, reached an unprecedented level of US$50 per barrel.[7]

- **U.S. reforms:** In December 2017, the U.S. Congress enacted the *Tax Cuts and Jobs Act* (TCJA) which reduced the U.S. federal corporate income tax rate from 35% to 21%, and the U.S. combined rate from 38.9% to 25.7%.[8] For purposes of comparison, in Alberta, the combined federal and provincial corporate income tax rate is 27%, following the increase of the provincial rate from 10% to 12% in 2015. Texas, on the other hand, has a zero state corporate tax rate, resulting in a total tax rate of 21%.[9]

- **Canadian bills:** On February 8, 2018, the Canadian government introduced Bill C-69, which includes a new impact assessment procedure and creates the Canadian Energy Regulator, to replace the National Energy Board.[10] The Canadian government had previously introduced, in May 2017, Bill C-48, the West Coast *Oil Tanker Moratorium Act*.[11] Bill C-69 is widely perceived as being detrimental to the Canadian economy. In a March 2019 editorial, *The Globe and Mail* opined that Bill C-69 would not solve the any problems, and would actually make things worse.[12] Similar views have been expressed about Bill C-48. In this case, the opposition is led by a coalition of First Nations groups that are promoting the Eagle Spirit pipeline.[13]

While global demand for hydrocarbons is set to keep increasing over the coming decades, Canada's oil and gas sector is facing serious challenges.

- **Carbon taxes:** Discussions about carbon taxes across Canada were ubiquitous during the past year. The federal carbon tax for large emitters became effective as of January 1st, 2019.[14] Saskatchewan was front and centre in this debate, having asked its highest court if the Greenhouse Gas Pollution

1. Dan Healing, "Devon Energy—with up to $9 billion in assets—is getting out of Canada's oilsands," *The Canadian Press*, February 20, 2019.

2. Shawn McCarthy, "Canadian crude production flattening out on tight pipeline capacity: IEA forecast," *The Globe and Mail*, March 11, 2019.

3. Jeffrey Jones, "Scotiabank CEO calls for national energy strategy to lure foreign capital back to oil sands," *The Globe and Mail*, March 7, 2019.

4. Jeff Lewis, "Court ruling on Trans Mountain pipeline another setback for oil industry," *The Globe and Mail*, August 30, 2018.

5. Dave Dormer, "U.S. judge denies request for Keystone XL pipeline pre-construction work," *CBC News*, February 15, 2019.

6. Kevin Orland, "Fresh blow to Canada's oil industry as key pipeline delayed by a year," *Financial Post*, March 4, 2019.

7. Matt Lundy, "Why Alberta's latest oil-price plunge is unprecedented," *The Globe and Mail*, November 27, 2018.

8. Erica York, "The Benefits of Cutting the Corporate Income Tax Rate," *Fiscal Fact No. 606*, Tax Foundation, August 14, 2018.

9. Deloitte, Canada, "Corporate income tax rates," December 31, 2019; Tax Foundation, State Texas, Taxes in Texas.

10. Parliament of Canada, *Bill C-69: An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*, First Reading version, February 8, 2018; Alexandre Moreau and Germain Belzile, *Energy Projects: Boosting Investment by Reducing Uncertainty*, Viewpoint, MEI, October 11, 2018.

11. Parliament of Canada, *Bill C-48: An Act respecting the regulation of vessels that transport crude oil or persistent oil to or from ports or marine installations located along British Columbia's north coast*, First Reading version, May 12, 2017.

12. "Globe editorial: Fixing the pipeline bill while it's still in the pipeline," *The Globe and Mail*, March 11, 2019.

13. Jesse Snyder, "First Nations coalition calls for rejection of Trudeau tanker ban; one group plans to file UN complaint," *National Post*, December 11, 2018.

14. Charles Kazaz *et al.*, "Federal Carbon Pricing System Coming into Force January 2019: How Will It Impact Your Business?" *Blakes Business Class*, December 17, 2018.

Table I-1

Global oil demand by scenario (mb/d)

			Current policies		New policies		Sustainable development	
	2000	2017	2025	2040	2025	2040	2025	2040
Road transport	30.1	41.2	46.2	53.6	44.7	44.9	40.5	23.0
Aviation and shipping	8.3	11.5	13.8	18.5	13.2	16.3	11.2	9.3
Industry and petrochemicals	14.5	17.8	20.9	23.8	20.7	23.3	20.0	20.7
Buildings and power	14.3	12.5	11.8	10.9	11.2	9.2	10.2	6.5
Other sectors	10.1	11.8	12.9	13.6	12.6	12.6	12.0	10.4
World oil demand	**77.3**	**94.8**	**105.5**	**120.5**	**102.4**	**106.3**	**93.9**	**69.9**

Source: International Energy Agency, *World Energy Outlook 2018*, 2018, p. 136.

Pricing Act is constitutional.[15] Alberta, having introduced a carbon tax years ago as a quid pro quo to facilitate the construction of pipelines, and also charging a higher carbon tax than most Canadian provinces, has so far been unable to secure the approval and construction of the pipelines it needs to move its oil.[16]

In its most recent World Energy Outlook, the International Energy Agency (IEA) states that under the New Policies scenario, its most likely scenario, demand for oil should increase gradually from 94.8 million barrels per day (mb/d) in 2017 to 102.4 mb/d in 2025 and 106.3 mb/d in 2040 (see Table I-1).[17] These numbers show that during the last year, the IEA increased its forecasted demand by 2.1 million barrels per day for 2025 and 1.4 million barrels per day in 2040.[18]

The most important issue for the sector is the lack of market access due to the increasing difficulty of getting pipelines built.

With regard to natural gas, the IEA also expects a steadily increasing demand from 3,752 billion cubic meters in 2017 to 4,293 billion m^3 in 2025 and 5,399 billion m^3 in 2040 (see Table I-2).[19] As with crude oil, the IEA raised its forecasted demand figures for natural gas between 2017 and 2018, by 119 billion m^3 for 2025 and by 95 billion m^3 for 2040.[20]

Therefore, both for oil and natural gas, not only is demand expected to increase, but it is expected to increase at a faster pace than anticipated earlier.

15. Adam Hunter, "Saskatchewan makes its legal case, arguing federal carbon tax is unconstitutional," *CBC News*, February 12, 2019.

16. Emma Graney and Janet French, "Alberta carbon tax: The province's most kicked political football," *Edmonton Journal*, March 7, 2019.

17. "The New Policies Scenario provides a measured assessment of where today's policy frameworks and ambitions, together with the continued evolution of known technologies, might take the energy sector in the coming decades. The policy ambitions include those that have been announced as of August 2018 and incorporates the commitments made in the Nationally Determined Contributions under the Paris Agreement, but does not speculate as to further evolution of these positions." International Energy Agency, *World Energy Outlook 2018*, 2018, p. 136.

18. International Energy Agency, *World Energy Outlook 2017*, 2017, page 157.

19. International Energy Agency, *op. cit.*, footnote 17, p. 174.

20. International Energy Agency, *op. cit.*, footnote 18, p. 346.

Table I-2

Global gas demand by scenario (billion m³)

			Current policies		New policies		Sustainable development	
	2000	2017	2025	2040	2025	2040	2025	2040
Power	907	1,515	1,668	2,226	1,618	1,981	1,602	1,265
Industry	631	872	1,089	1,522	1,076	1,436	1,041	1,221
Buildings	652	802	918	1,133	887	1,014	839	811
Transport	70	131	168	254	182	328	207	408
Other sectors	256	432	544	712	531	640	501	479
World natural gas demand	**2,516**	**3,752**	**4,386**	**5,847**	**4,293**	**5,399**	**4,189**	**4,184**

Source: International Energy Agency, *World Energy Outlook 2018*, 2018, p. 174.

In short, while global demand for hydrocarbons is set to keep increasing over the coming decades, Canada's oil and gas sector is facing serious challenges.

This Research Paper will look at some of those challenges in more detail. **Chapter 1** will look at the most important issue for the sector, namely the lack of market access due to the increasing difficulty of getting pipelines built. **Chapter 2** will examine various problematic aspects of carbon taxes as they are applied in Alberta and across Canada. **Chapter 3** will explore the effects of regulatory requirements in Alberta on oil and natural gas development projects. **Chapter 4** addresses the issue of energy corridors and First Nations partnerships. Finally, **Chapter 5** will look at several more minor but not insignificant issues affecting this important sector of the Canadian economy.

CHAPTER 1

Market Access

Pipelines—or the lack thereof—are certainly the oil and gas subject most frequently discussed by Canadians from coast to coast. As mentioned above, all major interprovincial or international pipeline projects are either stalled or experiencing undue delays. Lack of pipelines is also the subject having the greatest financial impact, over other factors such as carbon taxes. It affects not only the oil and gas industry, but also provincial finances and the whole Canadian economy.

In a May 2018 publication, the Fraser Institute found that from 2013 through 2017, after taking into account quality differences and transportation costs, the lack of pipelines had cost the Canadian economy C$20.7 billion, or over $4 billion per year on average.[21] During the 2009-2012 period, when there were no evident pipeline constraints, Western Canadian Select (WCS, the commonly used benchmark for Canadian oil) traded on average at a US$11.17 per barrel discount to West Texas Intermediary (WTI, the U.S. oil benchmark), which was a fair differential. The report assesses that in 2017, had pipeline capacity been sufficient, WCS at Hardisty, Alberta should have traded at a discount of US$11.91 per barrel to WTI at Cushing, Oklahoma, with US$6.28 of this difference due to transport costs and US$5.63 due to quality, WCS being heavier and more sour than WTI.[22]

In a note published in February 2018, Scotiabank's economists predicted that as Canadian oil production outstrips pipeline capacity, the WCS vs. WTI discount would increase to US$18 per barrel, which at that rate could cost the Canadian economy $15.6 billion per year.[23] The WCS vs. WTI discount actually peaked at US$50 per barrel, which led the Alberta government to impose production cutbacks.[24] While this 325,000 barrels per day cutback has temporarily eased the pain,[25] with the discount having since shrunk to its historic value (see Figure 1-1), it does not solve the problem.

A report published by RBC in May 2018 largely follows the same logic and finds that "the 'cost' of a sustained US$5/barrel larger-than-normal WCS-WTI price gap would be about C$4 billion to C$5 billion a year."[26]

During the 2009-2012 period, when there were no evident pipeline constraints, Western Canadian Select traded on average at a US$11.17 per barrel discount to West Texas Intermediary, which was a fair differential.

Finally, in a more recent report dated November 2018, TD economists state that deviation from the US$13 to $17 WCS-WTI spread is driven by the higher cost of rail transportation. They conclude that "until the structural transportation issues are addressed, there will remain significant concerns about the longer-term prospects [for] Canada's oil sector and its ability to compete."[27]

Crude Oil Supply and Demand in Canada and the United States

Canadian oil production has increased steadily over the past decade, from 2.6 million barrels per day in 2005 to 3.86 million barrels per day in 2014 and 4.64 million barrels per day for the first five months of 2018,[28] but pipeline capacity has not followed suit. In 2018, for the first time, output exceeded pipeline capacity (see Figure 1-2). Crude exports by rail exceeded 300,000 barrels per day in October 2018, also for the first time (see Figure 1-3). Transportation by rail may alleviate the problem, but it is not cheap: It is estimated that moving oil by train to the U.S. Gulf Coast costs an extra 50% to 100% compared to moving it by pipeline.[29] The aforementioned Scotiabank report estimated that the extra cost of transporting marginal crude by rail instead of

21. Elmira Aliakbari and Ashley Stedman, "The Cost of Pipeline Constraints in Canada," Fraser Research Bulletin, Fraser Institute, May 2018, p. 7.

22. *Ibid.*, pp. 5-7.

23. Scotiabank, "Pipeline Approval Delays: The Costs of Inaction," Global Economics – Commodity Note, February 20, 2018, p. 14.

24. "Globe editorial: Alberta's disastrous oil price discount? Blame Canada," *The Globe and Mail*, November 23, 2018.

25. Tony Seskus, "Alberta's OPEC-style oil cuts help boost prices—but concern over fallout remains," *CBC News*, January 14, 2019.

26. Royal Bank of Canada, "Lost in Transportation: Putting the discount on Canadian heavy oil in context," *RBC Economics Research*, Current Analysis, May 9, 2018, p. 4.

27. Omar Abdelrahman and Brian DePratto, "Discounted Oil: Canadian Oil Spreads and the Expected Economic Impacts," TD Economics, November 23, 2018, p. 7.

28. Government of Canada, National Energy Board, "Energy Supply and Demand Projections to 2040," 2018, pp. 42-43.

29. Government of Canada, National Energy Board, "Western Canadian Crude Oil Supply, Markets, and Pipeline Capacity," December 2018, p. 11; Yadullah Hussain, "Oil-by-rail economics suffers amid narrowing spreads," *Financial Post*, February 9, 2015.

Box 1-1

Market access for Canadian oil and gas at a glance

- Lack of pipelines is the subject having the greatest financial impact on the oil and gas industry, over other factors, and affects not only the industry, but also provincial finances and the whole Canadian economy.
- Except for the lack of pipelines, there is no reason anymore for WCS (the commonly used benchmark for Canadian oil) to trade at a discount to WTI (the U.S. oil benchmark), since the U.S. is awash with very light oils from fracking and needs our heavier oils (especially given that shipments of similar Mexican and Venezuelan crude to the U.S. are down).
- In 2018, the WCS vs. WTI discount peaked at US$50 per barrel, which led the Alberta government to impose production cutbacks of 325,000 barrels per day, temporarily easing the pain, but not solving the underlying problem.
- Improved access to tidewater would allow Canadian producers to service Asia, whose demand for oil is expected to increase by 9 million barrels per day by 2040, along with major increases in demand for natural gas.
- Lack of pipelines also increases the cost of crude oil for Eastern Canadian refineries, with Canada importing approximately 670,000 barrels of crude oil per day in 2017, around half of which came from overseas.

pipeline will be around C$7 billion per year in the coming years, and describes the situation as a self-inflicted wound.[30]

However, there is another issue: rising U.S. production. While Canada produced, on average, approximately 4.6 million barrels per day in 2018, it exported 3.6 million barrels per day, essentially to the U.S.[31] Crude oil exports by rail increased gradually from an average of 145,000 barrels per day at the beginning of the year to 350,000 barrels per day in December 2018.[32] Our southern neighbour consumed approximately 20.5 million barrels per day during 2018.[33] During the last decade, U.S. oil production has skyrocketed, increasing from 5.3 million barrels per day in 2009 to 11.0 million barrels per day in 2018, reaching 11.9 million barrels per day in January 2019 (see Figure 1-4).[34] The Energy Information Administration (EIA) expects this production to keep rising, to 12.4 million barrels per day in 2019 and 13.1 million

The WCS vs. WTI discount actually peaked at US$50 per barrel, which led the Alberta government to impose production cutbacks.

30. Scotiabank, *op. cit.*, footnote 23, p. 4.

31. National Energy Board, Energy Information, Statistics & Analysis, Crude Oil and Petroleum Products, Estimated Production of Canadian Crude Oil and Equivalent, 2018; National Energy Board, Energy Information, Statistics & Analysis, Crude Oil and Petroleum Products, Crude Oil Annual Export Summary – 2018.

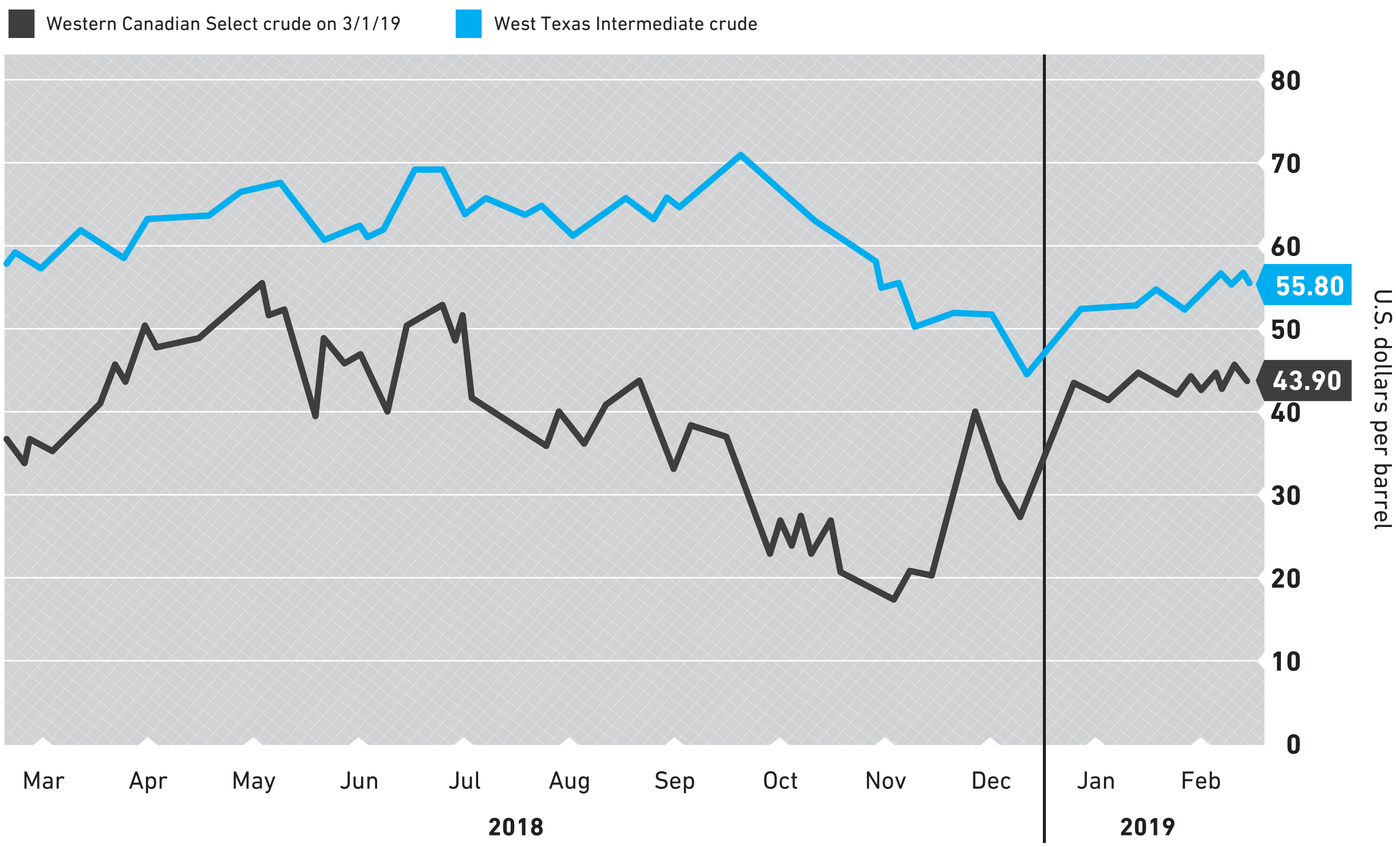
32. National Energy Board, Energy Information, Statistics & Analysis, Crude Oil and Petroleum Products, Canadian Crude Oil Exports by Rail – Monthly Data.

33. U.S. Energy Information Administration, *Short-Term Energy Outlook*, April 9, 2019.

34. U.S. Energy Information Administration, Data, Petroleum & Other Liquids, U.S. Field Production of Crude Oil.

Figure 1-1

Canadian and U.S. crude prices, March 2018 to March 2019



Source: Kevin Orland, "Canada Oil Industry Takes Fresh Hit With Key Pipeline Delay," *Bloomberg*, March 4, 2019.

barrels per day in 2020.[35] When adding in natural gas liquids, the EIA expects that the U.S. will become a net exporter of oil sometime in 2020.[36]

Therefore, the U.S., which a decade ago was craving Canadian oil for geopolitical security reasons, will not be a net importer of oil anymore. This situation will give the U.S. buyer significant leverage, and Canadians will be, more than ever, price takers. Although the oil barrels loaded onto tankers in the U.S. Gulf will not necessary be of Canadian origin, shipping oil from Fort McMurray, or from anywhere else in Canada, to the U.S. will be tantamount to shipping it overseas via U.S. ports. This is a paradigm shift. The regime under which North American oil prices were established during the past 10 years is over and is being gradually replaced by a new price regime. A decade ago, the U.S. was dependent on foreign oil and the price had to be such as to induce shippers to deliver overseas oil to U.S. ports. WTI prices, in Cushing, Oklahoma, were seldom trading at a discount to Brent, FOB North Sea.[37] Brent and WTI are comparable oils. Over the years, as U.S. oil production (to which we must add natural gas liquids, which are refined along with crude oil, as well as ethanol) increased,

Canadian oil production has increased from 2.6 million barrels per day in 2005 to 4.64 million barrels per day for the first five months of 2018, but pipeline capacity has not followed suit.

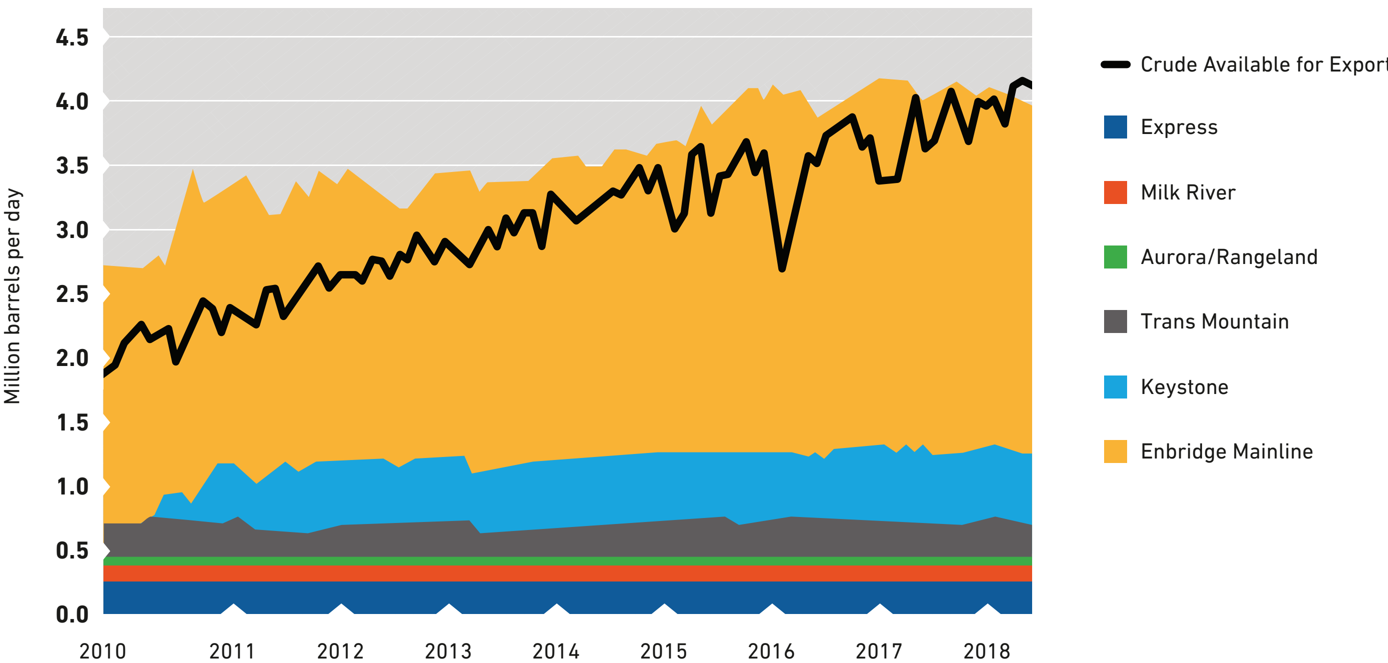
35. U.S. Energy Information Administration, *op. cit.*, footnote 33.

36. U.S. Energy Information Administration, "Short-Term Energy Outlook (STEO)," January 2019, p. 2.

37. U.S. Energy Information Administration, Today in Energy, Price Difference between Brent and WTI crude oil narrowing, June 28, 2013.

Figure 1-2

Canadian oil output and pipeline capacity, 2010-2018



Source: Government of Canada, National Energy Board, "Western Canadian Crude Oil Supply, Markets, and Pipeline Capacity," December 2018, p. 10.

and taking into account the landlocked Canadian supply, the U.S. gradually weaned itself from overseas oil. This is why WTI prices are now trading at a discount to Brent. During the past three years, this discount was around US$5 per barrel[38] and has lately exceeded US$9 per barrel.[39] That phenomenon increases Canada's problems, as WCS is priced compared to WTI. There is therefore even more money that Canada's oil foregoes by not being able to access tidewater.

The Impact of the Lack of Pipelines

How much is the lack of pipelines costing Canada? This is the billion-dollar question.

In a report dated March 2018, G. Kent Fellows of University of Calgary's School of Public Policy, based on historical data, assessed that a C$13.21 WTI-WCS spread represented fair market value and that the then-prevailing discount of C$38.67 represented a C$13 billion annual loss in net value, which would affect various stakeholders as shown in Figure 1-5.[40]

The extra cost of transporting marginal crude by rail instead of pipeline will be around C$7 billion per year in the coming years.

The Canadian Association of Petroleum Producers (CAPP), for its part, estimated the cost to the economy to be at least $13 billion in the first 10 months of 2018.[41] The annual losses estimated by Fellows are moreover compatible with estimates by other researchers such as RBC's Nathan Janzen[42] and Scotiabank's Jean-François Perrault and Rory Johnson.[43] The Alberta government

38. U.S. Energy Information Administration, *op. cit.*, footnote 33.

39. Oilprice.com, Oil Price Charts.

40. G. Kent Fellows, "Energy and Environmental Policy Trends: The Invisible Cost of Pipeline Constraints," The School of Public Policy, University of Calgary, March 6, 2018.

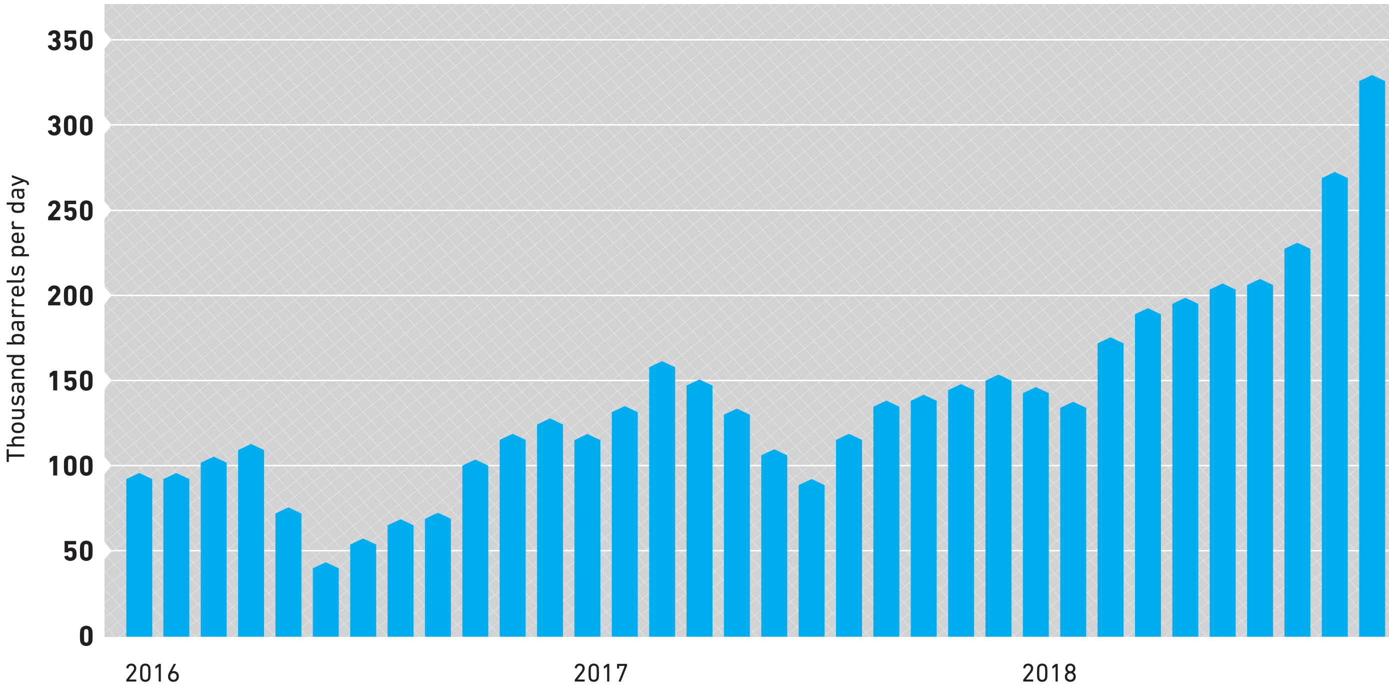
41. Dan Healing, "Oil price discounts could be costing Canadian economy as much as $100 billion a year," The Canadian Press, November 11, 2018.

42. Royal Bank of Canada, *op. cit.*, footnote 26.

43. Scotiabank, *op. cit.*, footnote 23.

Figure 1-3

Canadian crude exports by rail, 2016-2018



Source: Government of Canada, National Energy Board, "Western Canadian Crude Oil Supply, Markets, and Pipeline Capacity," December 2018, p. 11.

estimated that every annual average $1 increase in the WCS-WTI differential above US$22.40 per barrel costs its treasury C$210 million. In Saskatchewan, the government estimates that each $1 increase in this differential costs about $15 million in revenue, assuming a WTI price of US$58 per barrel.[44]

Crude oil exports by rail increased gradually from an average of 145,000 barrels per day at the beginning of the year to 350,000 barrels per day in December 2018.

Quality Discount

There is, however, more to it. Having similar viscosities and sulphur contents, WCS is often compared to Mexico's Maya oil (see Figure 1-6). Maya, which used to trade at a discount to WTI,[45] has recently traded at or close to par with WTI.[46] If Canada had enough pipeline capacity, the same would apply to WCS. In the United States, oil produced by fracking now represents over 60% of all production.[47] Fracked oil is very light and richer in gasoline, and poorer in distillates (Diesel, heating oil, and jet-fuel), than conventional oil. During the past few years, U.S. crude became much lighter than it used to be on average, due to the increase in fracking, resulting in an increase in the production of tight oil (see Figure 1-7).[48] Adding natural gas liquids further reduces the viscosity of U.S. oil production. Since the demand profile (gasoline vs. distillates) is essentially the same as it was a few

44. Dan Healing, *op. cit.*, footnote 41.

45. U.S. Energy Information Administration, "Short-Term Energy Outlook Supplement: Brent Crude Oil Spot Price Forecast," July 10, 2012, p. 3.

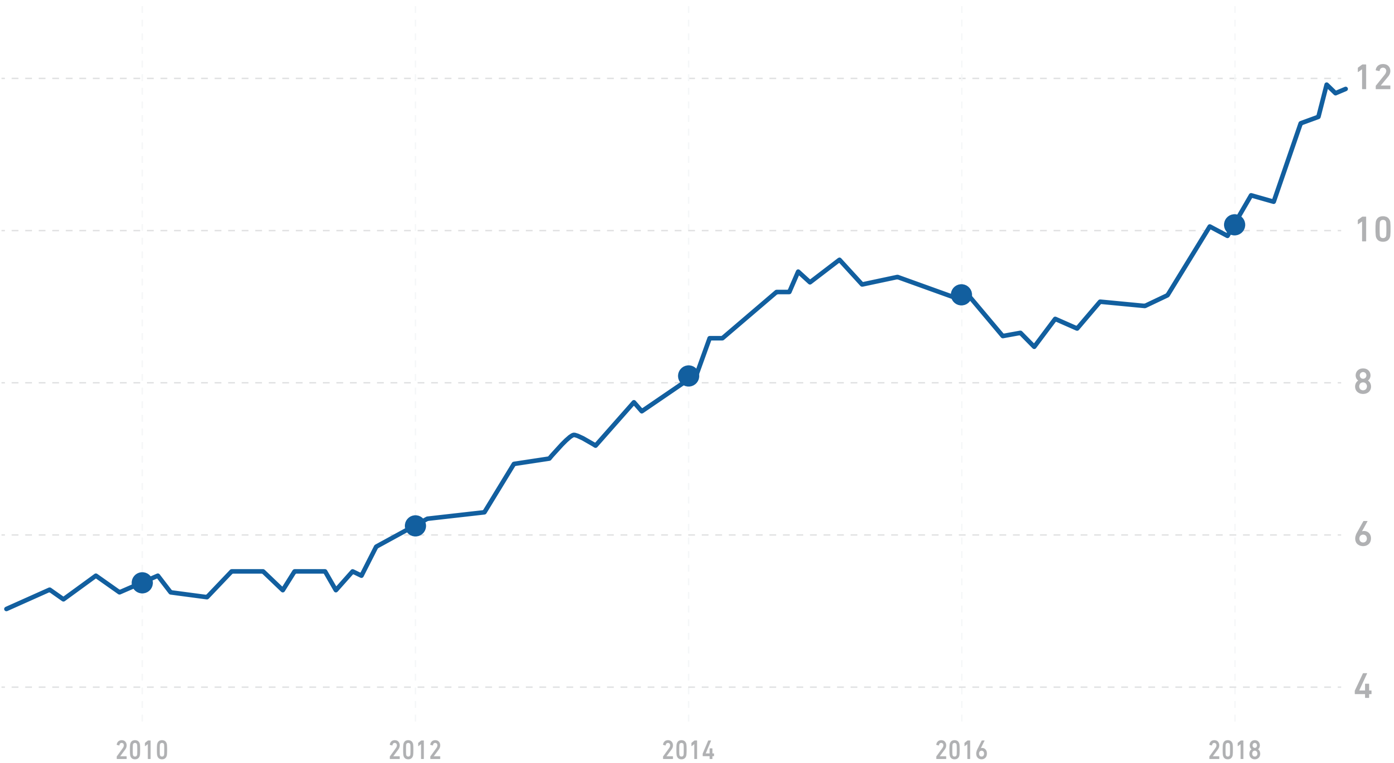
46. Geoffrey Morgan, "What discount? Gulf Coast paying premium prices for Canadian oil—but only 450,000 bpd make it there," *Financial Post*, October 25, 2018.

47. U.S. Energy Information Administration, Data, Petroleum & Other Liquids, Data, Tight oil production estimates by play (Monthly); U.S. Energy Information Administration, *op. cit.*, footnote 38.

48. U.S. Energy Information Administration, Data, Petroleum & Other Liquids, Crude Oil and Lease Condensate Production by API Gravity.

Figure 1-4

United States Crude Oil Production, 2009-2019, million barrels per day



Source: Trading Economics, United States Crude Oil Production, 10Y, consulted April 26, 2019.

years ago, refiners are seeking heavier oils to blend in, in order to match the demand profile.[49]

The U.S. Gulf Coast is the world's largest market for heavy and sour (high sulphur) crudes, such as Canada's WCS and Mexico's Maya. During the past decade, shipments of Mexican and Venezuelan crude to U.S. Gulf Coast ports were halved, from around two and a half million barrels per day down to about one million.[50] While the reduction in Mexican crude oil availability is due to the depletion of their oil fields,[51] the reduction in availability of Venezuelan crude oil is due to the political situation in that country.

The U.S., which a decade ago was craving Canadian oil for geopolitical security reasons, will soon not be a net importer of oil anymore.

To be clear: The demand for Canada's heavy oil has been increasing. Except for the lack of pipelines, there is no reason anymore for WCS to trade at a discount to WTI, despite its lower quality, since the U.S. is awash with very light oils. A recent analysis by the C.D. Howe concurs with this view.[52] Heavy oil represents 50% of Canadian oil production;[53] a US$5 premium on half of

49. U.S. Energy Information Administration, Data, Petroleum & Other Liquids, U.S. Product Supplied of Finished Motor Gasoline; U.S. Energy Information Administration, Data, Petroleum & Other Liquids, U.S. Product Supplied of Distillate Fuel Oil.

50. Geoffrey Morgan, *op. cit.*, footnote 46.

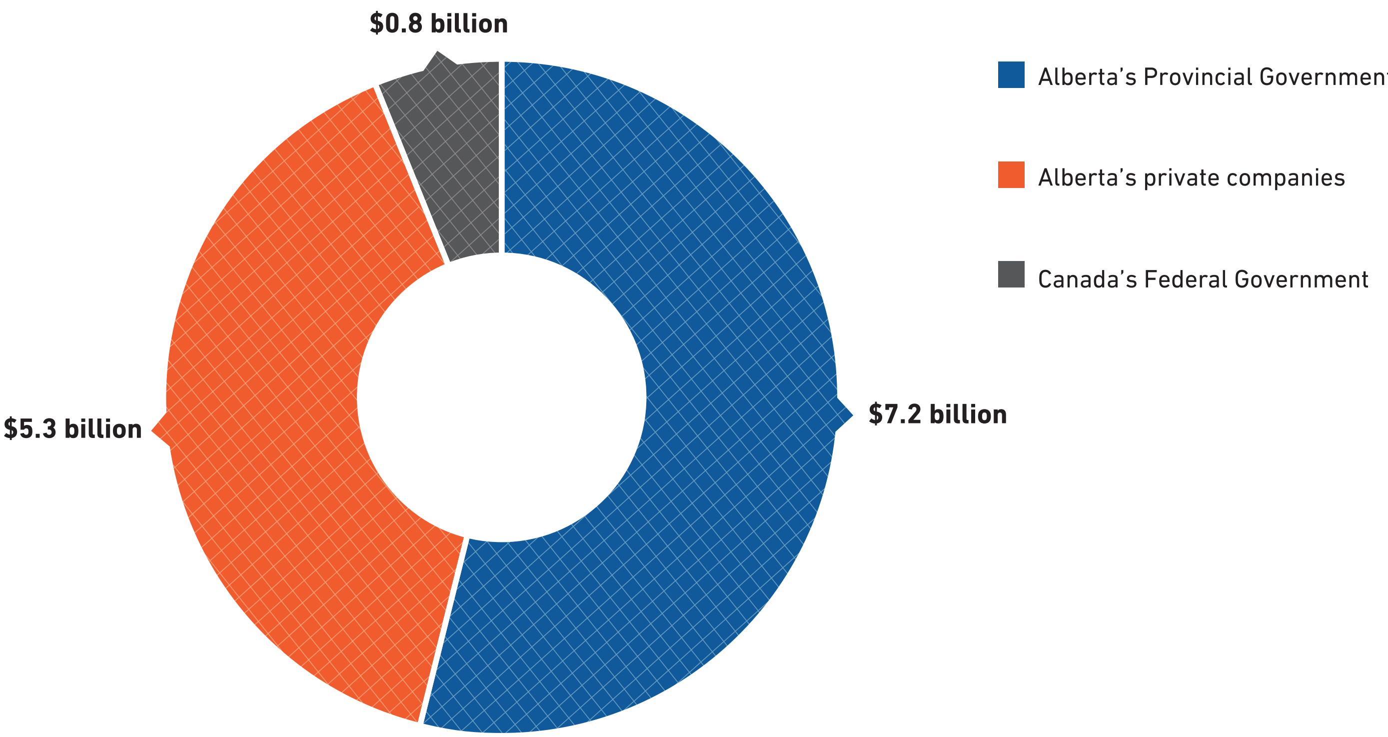
51. Petróleos Mexicanos, "Liquid Hydrocarbons Production (thousand barrels per day)," *Monthly Petroleum Statistics.*

52. Brian Livingstone, "Alberta can boost revenues from crude production by giving financial assistance for rail transport," C.D. Howe Institute, April 4, 2019.

53. Omar Abdelrahman and Brian DePratto, *op. cit.*, footnote 27.

Figure 1-5

Annual revenue losses associated with high WTI-WCS discount prevailing in March 2018



Source: G. Kent Fellows, "Energy and Environmental Policy Trends: The Invisible Cost of Pipeline Constraints," The School of Public Policy, University of Calgary, March 6, 2018.

Canadian crude oil exports would represent extra revenues in excess of US$3 billion per year.[54]

Shipping by rail is another extra expense: Pipeline fees from Edmonton/Hardisty to the U.S. Gulf are between US$9.20 and $10.00 per barrel, depending on the type of oil.[55] In comparison, shipment by rail costs between US$12 (rail-Unit Train) and US$21 (Rail-Manifest).[56] Since over 290,000 barrels of oil were shipped daily by rail during the second half of 2018, we estimate that, on an annualized basis, this represents an out-of-pocket expense in excess of US$700 million per year.[57] Whichever way we look at the prevailing situation, the lack of pipelines is costing the Canadian economy billions and billions of dollars. Most of our exports are directed to the

The demand for Canada's heavy oil has been increasing. Except for the lack of pipelines, there is no reason anymore for WCS to trade at a discount to WTI, despite its lower quality, since the U.S. is awash with very light oils.

54. The exportation of Canadian crude oil was 3.6 million barrels per day (see above). Heavy oil exports was 1.8 million barrels per day. Therefore, the US$5 premium represents roughly $9 million per day, and $3.3 billion per year.

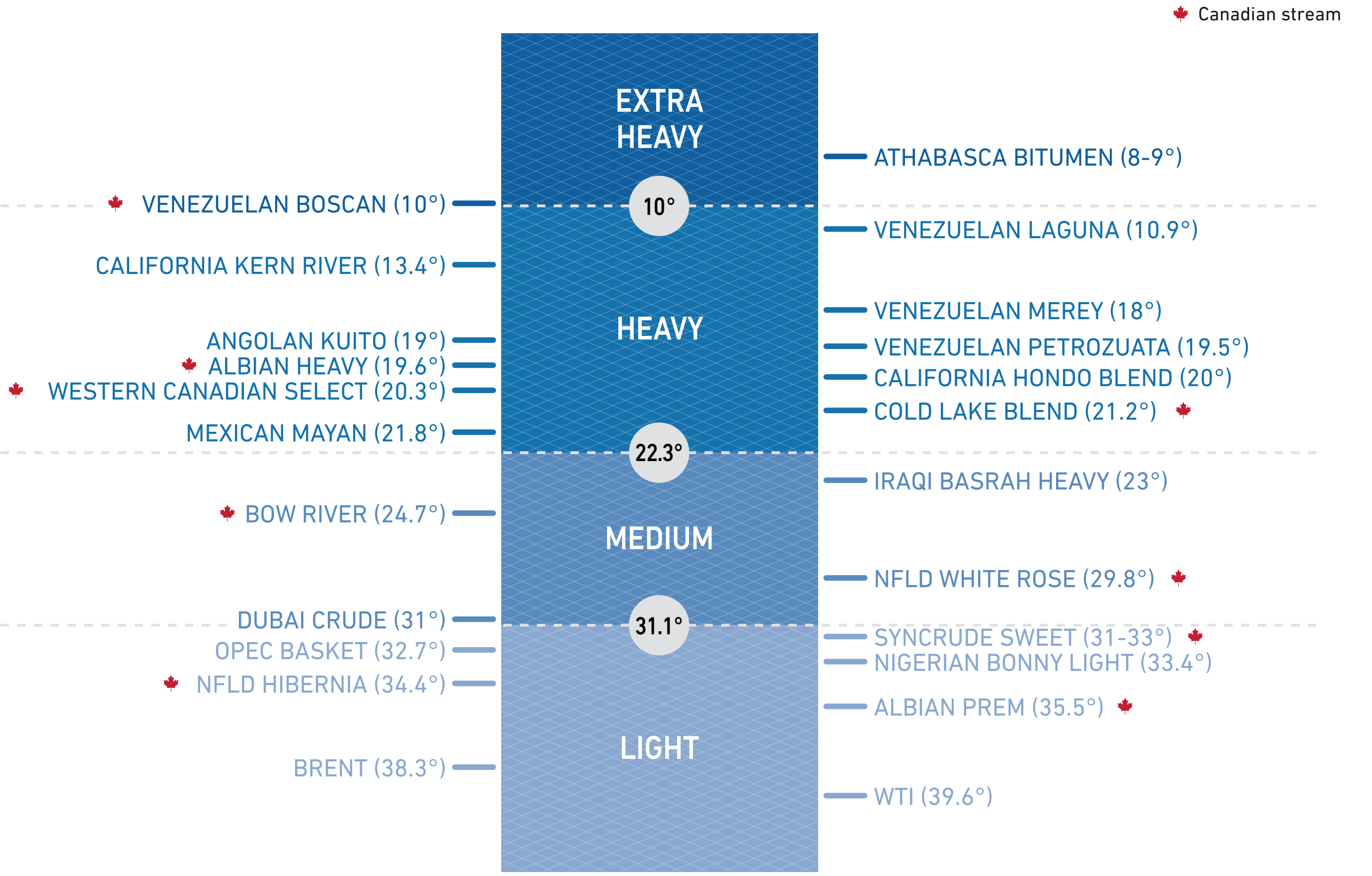
55. TransCanada Keystone Pipeline GP Ltd., "International Joint Rate Tariff Containing Rates Applying to the Transportation of Petroleum," NEB Tariff No. 35, January 4, 2019, p. 2.

56. Yadullah Hussain, *op. cit.*, footnote 29.

57. National Energy Board, *op. cit.*, footnote 32. To estimate this figure, we calculated that the average cost for rail shipment is US$16.50 (between $12 and $21) and for pipelines US$9.60 (between $9.20 and $10). On average, the cost of shipping a barrel is US$6.90 higher by train than by pipeline. Given that 290,000 barrels per days were sent by train on average during the second half of 2018, we estimate that the extra cost is US$2 million per day, $730 million per year.

Figure 1-6

Different types of crude oil



Source: *Oil Sands Magazine*, Western Canadian Select Explained, May 3, 2017.

U.S. which, as mentioned, will soon be self-sufficient in both crude oil and natural gas.

National Policies

The U.S. has always had strong national policies to guarantee its energy security. Canada has no such policy despite being the fourth largest producing country in the world after the United States, Saudi Arabia, and Russia, but ahead of China, Iran, and Iraq.[58] Nevertheless, Canada is unable to supply its own East Coast demand, having to rely on imported oil.

A decade ago, we could have considered the U.S. as a benevolent neighbour that badly needed all the oil and gas we could provide and could rely on Canada's polit-

The lack of market diversification makes our largest exporting industry a price taker without any market pricing ability, and exposes it to arbitrary decisions and potential tariffs.

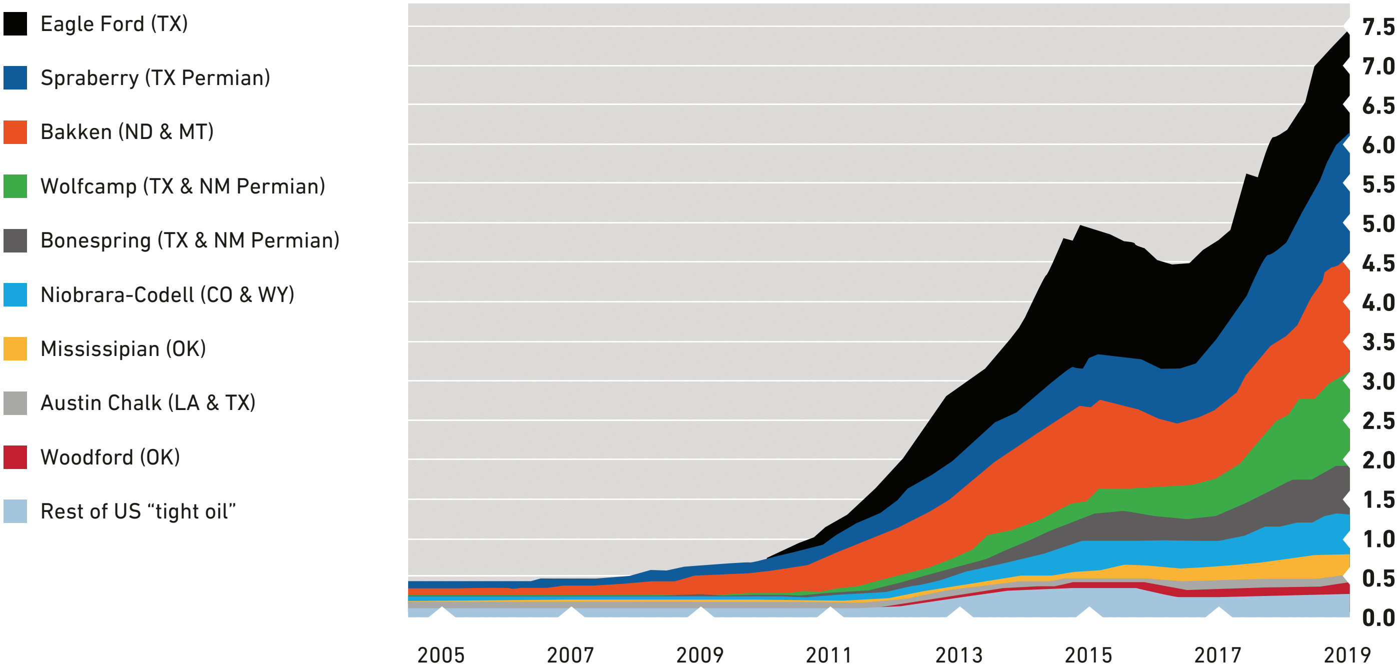
ical stability. Not anymore. This first became apparent under President Obama, who vetoed the construction of the Keystone XL pipeline.[59] Last year, despite the U.S. being strategically short of aluminium, President Trump imposed tariffs on Canadian aluminium and steel

58. Amanda Kay, "Top Oil-producing Countries", *Investing News*.com, December 4, 2018.

59. Juliet Eilperin and Katie Zezima, "Obama vetoes Keystone XL bill," *The Washington Post*, February 24, 2015.

Figure 1-7

U.S. tight oil production—selected plays, million barrels of oil per day



Note: Data are through January 2019 and represent EIA's official tight oil estimates, but are not survey data. State abbreviations indicate primary state(s).
Source: U.S. Energy Information Administration, Data, Petroleum & Other Liquids, Crude Oil and Lease Condensate Production by API Gravity.

While the International Energy Agency expects North American and European demand for petroleum products to decrease between 2017 and 2040, Asia's demand is expected to increase by 9 million barrels per day.

production.[60] Americans will do what they consider good for them. And today's situation, with a deep discount on the price they pay for our oil, can certainly be described as a win for U.S. users. Furthermore, by not diversifying our markets, we are exposing Canada's largest export to the potential imposition of an arbitrary decision which would be devastating for the country. In 2018, Canada's exports were worth C$584 billion. Crude oil and natural gas alone represented 18% of these exports, or C$96.3 billion (essentially to the U.S.).[61] The lack of market diversification makes our largest exporting industry a price taker without any market pricing ability, and exposes it to arbitrary decisions and potential tariffs.

Tidewater Access

To the above calculations must be added the loss of earnings due to the lack of access to tidewater. Moving oil from Edmonton to Burnaby costs approximately C$2.50 per barrel.[62] The tariff for a pipeline to northwestern British Columbia should be similar, since the distance is almost the same. Crude oil FOB (Freight on Board) Burnaby, or ideally the Price Rupert area, should

60. David J. Lynch *et al.*, "Trump imposes steel and aluminum tariffs on the E.U., Canada and Mexico," *The Washington Post*, May 31, 2018.

61. Oil exports to the US represented 96% of the total. Statistics Canada, Canadian International Merchandise Trade Database, Merchandise imports and exports between "Canada" and "World", by Harmonized System section, customs basis, year-to-date 2018, commodity "270900 Petroleum oils and oils, obtained from bituminous minerals, crude, commodity" and "271121 Natural gas, in gaseous state."

62. Government of Canada, National Energy Board, Energy Information, Integrated Energy Analysis, Canada's pipeline system portal, Pipeline Profiles: Trans Mountain.

not trade at WTI prices but at a price similar to the Brent price (always expedited by ship), based on recent prices, a US$5 increase. The Trans Mountain expansion project would allow an extra 590,000 barrels per day to reach tidewater.[63] Once loaded onto tankers in Vancouver, this crude could reach the U.S. West Coast as well as the U.S. Gulf, via the Panama Canal, for a maximum additional cost of US$4 per barrel, which is the maximum cost per barrel from the United States coasts to anywhere in the world.[64]

While the Northern Gateway project was a 525,000 barrels per day project reaching tidewater at Kitimat, BC,[65] the proposed Eagle Spirit project, promoted by a coalition of First Nations, would be a much bigger endeavour, having an initial projected capacity of 2 million barrels per day.[66] This project would be a game changer. While Trans Mountain would access tidewater, Burnaby, its marine terminal, lacks the capability of servicing large, very large, and ultra large crude carriers which would enable the servicing of Asia.[67]

As was mentioned earlier, demand for both crude oil and natural gas is expected to increase steadily during the coming decades. This increase will not affect all markets the same way. While the International Energy Agency expects North American and European demand for petroleum products to decrease by 3 million and 4.5 million barrels per day, respectively, between 2017 and 2040, the IEA expects Asia's demand to increase by 9 million barrels per day over the same period. The forecasted increases are of 3.5 mb/d in China, 4.7 mb/d in India and 2.1 mb/d in South East Asia.[68] The IEA also forecasts major increases in natural gas demand by the same countries during the period. It expects annual compounded growth of 4.7%, 4.9%, and 2.3%, respectively, in natural gas demand by China, India, and South East Asian countries.[69] An earlier report by the Fraser Institute assessed that if Canada could export one million barrels of oil per day to markets accessible from ocean ports, this could provide extra revenues exceeding C$4.2 billion per year when oil trades around US$60 per barrel.[70]

Finally, lack of pipelines also increases the cost of crude oil for Canadian refineries. In 2017, Canada imported approximately 670,000 barrels of crude oil per day. Of these, approximately 350,000 barrels per day came from the U.S., and the remaining from overseas countries including Saudi Arabia, Algeria, Norway, Nigeria, Angola, Azerbaijan, Kazakhstan, and the United Kingdom. The bulk of this demand went to New Brunswick (approximately 260,000 barrels per day) and the remainder was split between Quebec (around 150,000 barrels per day) and Newfoundland and Labrador.[71]

Lack of pipelines also increases the cost of crude oil for Canadian refineries. In 2017, Canada imported approximately 670,000 barrels of crude oil per day.

Crude oil imported from overseas is benchmarked against Brent. As mentioned earlier, Brent is trading at around a US$5 premium to WTI. We observe that pipeline tariffs from Alberta to Montreal[72] are slightly cheaper than tariffs from Alberta to the U.S. Gulf, especially for heavy crude oil.[73] Given that the main existing pipeline path from Alberta to Montreal circumvents the Great Lakes via a southern route, we can assume that tariffs via a more direct route would allow oil to be moved all the way from Alberta to Saint John, New Brunswick at a cost similar to the cost of moving oil from Alberta to the U.S. Gulf. This would result in savings of approximately US$5 per barrel, for an annual saving of approximately C$750 million, and provide a secure supply in

63. Trans Mountain, Expansion Project, Overview.

64. Argus, "Argus Freight: Daily international freight rates and market commentary," Issue 19-21, January 30, 2019; CME Group, conversion calculator, Distillate.

65. "Northern Gateway pipeline unlikely to start up by 2018," The Canadian Press, September 4, 2014.

66. "Eagle Spirit Pipeline project could win NEB approval, president says," The Canadian Press, September 25, 2018.

67. Catherine Ngai, "Canada oil sands Asia export dream faces port bottleneck," Reuters, November 20, 2016.

68. International Energy Agency, *op. cit.*, footnote 1, p. 138.

69. *Ibid.*, p. 176

70. Gerry Angevine and Kenneth P. Green, "The Costs of Pipeline Obstructionism," Fraser Institute, July 2016, p. 10.

71. Government of Canada, National Energy Board, Energy Information, Integrated Energy Analysis, Energy Markets, Market Snapshots, Market Snapshot: Imports of crude oil decreased in 2017, March 7, 2018.

72. The transportation rates for the Enbridge main line from Edmonton to Nanticoke (ON) were between US$5 and US$6 per barrel, and from Edmonton to Montreal between US$6 and US$9 (depending on the type of crude oil). Enbridge Pipelines Inc. (Line 9), "Enbridge Energy, Limited Partnership: International Joint Rate Tariff Applying on Crude Petroleum," NEB No. 442, November 28, 2018.

73. The TransCanada rate between Hardisty and Port Arthur is between US$9.20 to US$10. TransCanada Keystone Pipeline GP Ltd., *op. cit.*, footnote 55, p. 2.

case of geopolitical events.[74] For example, during the 2018 spat between Canada and Saudi Arabia, some were expecting the Saudis to curtail their crude oil exports to Canada, and raised their voices in favour of self-reliance instead of depending on countries with poor human rights records.[75] A 100% Canadian pipeline would also guarantee Canadian sovereignty and independence with regard to the U.S.

74. Authors' calculations: 670,000 barrels per day imported, minus 350,000 barrels per day imported from the US which are priced at WTI price, equals 320,000 barrels per day imported from overseas which are priced at Brent price (i.e., US$5 premium to WTI). Therefore, 320,000 barrels per day x US$5 x 365 days per year = US$584 million. At 1.30 C$ per US$, this means C$759 million per year. See Bank of Canada, Statistics, Exchange Rates, Annual Exchange Rates, 2017.

75. Konrad Yakabuski, "Canada will be hooked on Saudi oil for a long time yet," *The Globe and Mail*, October 30, 2018; Dan Healing, "Canada can easily replace Saudi Arabian crude oil imports: economist," The Canadian Press, August 7, 2018.

CHAPTER 2

Carbon Taxes

This Research Paper neither endorses nor opposes the principle of carbon taxes, nor does it address carbon taxes—or levies—at the consumer level. Should carbon taxes be enacted at the corporate level, their structure should respect the basic principles of economics.

The political party that won the provincial elections in Alberta on April 16, 2019, has clearly expressed its intention to axe the current provincial carbon tax for consumers (not addressed in this report) and join the legal challenge initiated by the governments of Saskatchewan, Ontario, New Brunswick, and Manitoba against the federal carbon tax. This Research Paper does not take a position on the potential outcome of this legal challenge, nor its merit.

Our central argument, rather, is that so long as a carbon tax is in place, there are no valid reasons that justify it being, effectively, 50% higher than the de facto rate currently in place in Quebec as a result of its cap & trade system, as Alberta's $30 carbon tax is—and even less to justify it being about twice as high as the de facto Quebec rate, as the federal tax will be by 2022.

Alberta's Carbon Tax

In 2002, Alberta introduced a plan to reduce greenhouse gases,[76] and in 2007, it became the first Canadian province—as well as one of the first jurisdictions in North America—to introduce a carbon levy or carbon tax. That tax, the Specified Gas Emitters Regulation (SGER), targeted all major facilities producing over 100,000 tonnes of CO_2 per year in the hope that these emitters would reduce the intensity of their emissions by 12% vs. 2005 levels (the Baseline). Companies could either a) achieve these reductions internally, b) acquire carbon credits from other industries in the province, or c) contribute $15 per tonne of greenhouse gas (GHG) emissions to the Climate Change and Emissions Management Fund (CCEMF). Companies could also accumulate carbon credits for future use.[77]

British Columbia followed suit in 2008 with a carbon tax of its own,[78] and Quebec introduced its cap-and-trade system in 2013.[79]

In 2017, ten years after the Alberta government introduced its carbon tax, it had not resulted in an absolute decrease of CO_2 emissions (they increased by 18%), and it was obvious that the province would miss its emissions target for 2020 (which was to stabilize its emissions and begin reducing their level).[80]

So long as a carbon tax is in place, there are no valid reasons to justify it being about twice as high as the de facto Quebec rate, as the federal tax will be by 2022.

In 2015, Alberta's new government announced that carbon levies would increase from $15 per tonne to $20 in 2016 and again to $30 in 2017. The goal of this new regime was to require that each producer reduce overall GHG emissions by 20% from a baseline unique to each individual producer.[81] The government also announced that a new carbon tax regime would replace the SGER. The Carbon Competitiveness Incentive Regulation (CCIR) was introduced in 2017 and became effective in 2018. The CCIR applies to the same facilities covered by the SGER and also covers emissions from industrial processes, as well as indirect emissions associated with electricity, heat, and hydrogen imported by a facility.[82] Under the CCIR, conventional oil and natural gas producers are

76. Government of Alberta, "Albertans & Climate Change: A Plan for Action – Draft plan to reduce greenhouse gases; enhance economy," *News release*, May 21, 2002.

77. Andrew Read, "Climate change policy in Alberta," Pembina Institute, Backgrounder, July 2014, p. 1; David S. Hume, "Alberta's Carbon Policy: A Work in Progress," Capstone Project, under the supervision of Dr. Jack Mintz, School of Public Policy of the University of Calgary, September 19, 2013, pp. 9-12.

78. Government of British Columbia, Environmental Protection & Sustainability, Climate Change, Climate Planning & Action.

79. Government of Quebec, Ministère de l'Économie et de l'Innovation, Secteurs, Environnement, Aperçu de l'industrie, Marché du carbone; Germain Belzile, "GHG Reductions: Ambitious Targets for an Insignificant Impact," Viewpoint, MEI, January 17, 2019; Germain Belzile and Mark Milke, "The Carbon Market: Chasing Away Jobs and Capital without Reducing GHGs," Economic Note, MEI, June 13, 2018.

80. Environment and Climate Change Canada, "Canadian Environmental Sustainability Indicators Greenhouse Gas Emissions," 2019, p. 23; Pembina Institute, "Q&A on Alberta's climate strategy," December 2014, p. 1.

81. Justin Giavonnetti, "Alberta to double carbon tax by 2017, strengthen emissions reduction targets," *The Globe and Mail*, June 25, 2015.

82. Sarah Dobson, Jennifer Winter, and Brendan Boyd, "The Greenhouse Gas Emissions Coverage of Carbon Pricing Instruments for Canadian Provinces," School of Public Policy Research Paper, Vol. 12:6, University of Calgary, February 2019, p. 10.

Box 2-1

Carbon taxes at a glance

- There are no valid reasons that justify a carbon tax being 50% higher than the de facto rate currently in effect in Quebec's cap & trade system, as Alberta's $30 carbon tax is—and even less to justify it being about twice as high as in Quebec, as the federal tax will be by 2022.
- The carbon tax regimes now in force across Canada ignore a few realities: a) that carbon emissions are first and foremost a consumption problem; b) that while companies don't vote, they may move to another jurisdiction, which is known as carbon leakage; and c) that Canada is a trading nation and does not live in isolation.
- Alberta and Saskatchewan produce more carbon than they consume, and are therefore penalized by Canada's production-based carbon taxes; B.C., Ontario, and Quebec all consume more carbon than they produce, and are thus favoured by Canada's methodology.
- It is pointless to shut down a CO_2 emitting facility if the goods it produces are to be later imported or produced in another jurisdiction which does not have as strict pollution-control measures.
- Any carbon tax should be compensated by an equivalent reduction of other taxes, preferably the ones that are the most destructive in economic terms: corporate taxes on profits and personal income taxes, for example.
- Allowing emitters to use all the tools available to them to achieve the stated goal, at the lowest possible cost, would reduce the adverse economic impact of these policies on the Canadian economy.

granted a temporary exemption until 2023, representing approximately 13% of Alberta's total emissions.[83]

As its name suggests, Alberta's Carbon Competitiveness Incentive Regulation purports to provide companies operating in a given sector an incentive to become best-of-class. Facilities are divided into groups operating in similar situations. For the oil sector, these groups are oil sands mines, oil sands in-situ facilities, oil refineries, and upgraders.[84] For each sector, an Output Based Allocation (OBA) is established. When the program was announced, Alberta's Environment Minister said, "The improved rules that we are releasing today

83. *Ibid.*, p. 30.

84. Government of Alberta, "Output-Based Allocation Stakeholder Session 4," December 6, 2017, p. 35.

will reward companies that use best practices and reward investment in modern and efficient facilities."[85] While this may sound unobjectionable, the devil is in the details. If the benchmark were the midpoint of the distribution, there would be as many winners as losers, and the impact would be neutral. Companies would be incentivized to improve their practices to become best-of-class. However, the emissions benchmark, i.e., the neutral point, was established at a much higher level, the top-quartile level—resulting in three losing facilities for one winner.[86] Figure 2-1 illustrates this point.

Additionally, a tightening rate (an annual reduction in free permits allocated) of 1% was put in place, beginning in 2020.[87] The facilities whose emissions exceed the benchmark must buy offsets or pay $30 for every tonne of emissions over the limit.[88] This means that about three quarters of facilities will have to disburse to keep operating. Furthermore, the federal government requirement for provincial carbon pricing implies that this $30 charge is scheduled to increase to $40 in 2021 and $50 in 2022.[89] However, the scheduled increase was cancelled by Premier Notley in August 2018 following the Federal Court of Appeal's decision concerning the Trans Mountain pipeline expansion.[90] Finally, compliance to the CCIR was phased in, with 50% and 75% compliance targeted in 2018 and 2019 respectively, and the full benchmark being applicable in 2020.[91]

When Alberta announced the introduction of the CCIR, the Canadian Association of Petroleum Producers (CAPP), immediately expressed its fears about the program: "It looks like, by our calculations, about a five-fold increase in costs to our industry from the current carbon levy."[92] By its assessment, the CCIR will cost its members approximately $700 million during the period from 2018 to 2020.[93]

Figure 2-2, drawn from Alberta's Fiscal Plans for 2018, validates this claim. Hence, expected revenues from large emitters total $1.386 billion for the 2017-2018, 2018-2019, and 2019-2020 budget years taken together. Since the oil and gas sector represents approximately 50% of Alberta's CO_2 emissions,[94] we can attribute half of this amount to the oil and gas sector, which is just under $700 million. We also notice that the cost for large emitters grows as full compliance with the benchmark becomes mandatory and as the out-of-pocket cost for non-compliance increases.

The federal government requirement for provincial carbon pricing implies that this $30 charge is scheduled to increase to $40 in 2021 and $50 in 2022.

According to researchers from the University of Calgary's School of Public Policy, the new federal carbon pricing system is very similar to Alberta's CCIR. One difference is that the federal program targets facilities producing over 50,000 tonnes of CO_2 per year vs. the 100,000 tonnes of CO_2 per year threshold used by Alberta's CCIR.[95]

That said, a carbon tax does not have to operate this way.

Types of Carbon Taxes

Carbon taxes, in economic theory, are imposed to offset a negative externality, in this case, the production of carbon dioxide or CO_2. Taxes to offset negative externalities were initially proposed in 1920 by Arthur C. Pigou, a British economist, and are also called Pigovian (or Pigouvian) taxes. The concept of carbon taxes, as a tool to reduce carbon emissions, has been around for decades and figured in the 1990 report of the Intergovernmental Panel on Climate Change (IPCC) which led to the 1992 United Nations Framework Convention on Climate

85. The Canadian Press, "Alberta sets out plan to reduce carbon emissions from big industries," *CBC News*, December 6, 2017.

86. Sarah Dobson *et al.*, *The Ground Rules for Effective OBAs: Principles for Addressing Carbon-Pricing Competitiveness Concerns through the Use of Output-Based Allocations*, School of Public Policy Research Paper, Vol. 10:17, University of Calgary, June 2017, p. 12; Government of Alberta, "Industrial Greenhouse Gas Regulatory System Carbon Competitiveness Incentive Regulation," Working Document, May 9, 2018, p. 11.

87. Government of Alberta, *op. cit.*, footnote 84, pp. 25 and 46.

88. The Canadian Press, *op. cit.*, footnote 85.

89. Government of Alberta, *op. cit.*, footnote 84.

90. Dean Bennett, "Rachel Notley pulls Alberta out of federal climate plan after pipeline decision," The Canadian Press, August 30, 2018.

91. Government of Alberta, *op. cit.*, footnote 84.

92. The Canadian Press, *op. cit.*, footnote 85.

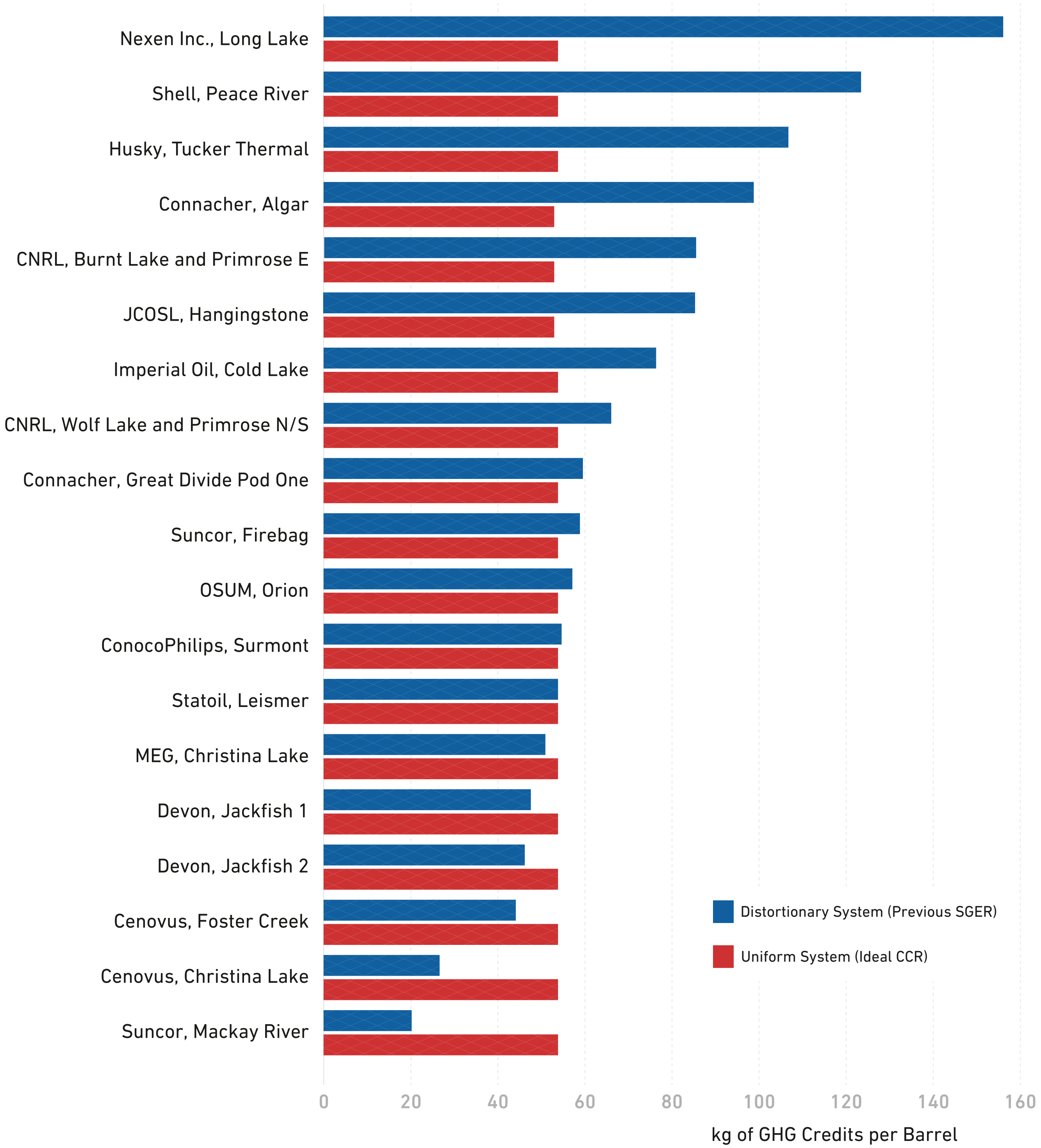
93. Canadian Association of Petroleum Producers, "Investment of Carbon Proceeds into Oil and Gas Production Operations: Making the case for the oil and gas sectors ability to contribute to provincial emissions reductions and economic growth," submitted by ICF, May 2018, pp. 2-3.

94. National Energy Board, Energy Information, Integrated Energy Analysis, Energy Markets, Provincial and Territorial Energy Profiles, Provincial and Territorial Energy Profiles – Alberta, March 12, 2019.

95. Sarah Dobson, Jennifer Winter, and Brendan Boyd, *op. cit.*, footnote 82, pp. 5 and 9-10.

Figure 2-1

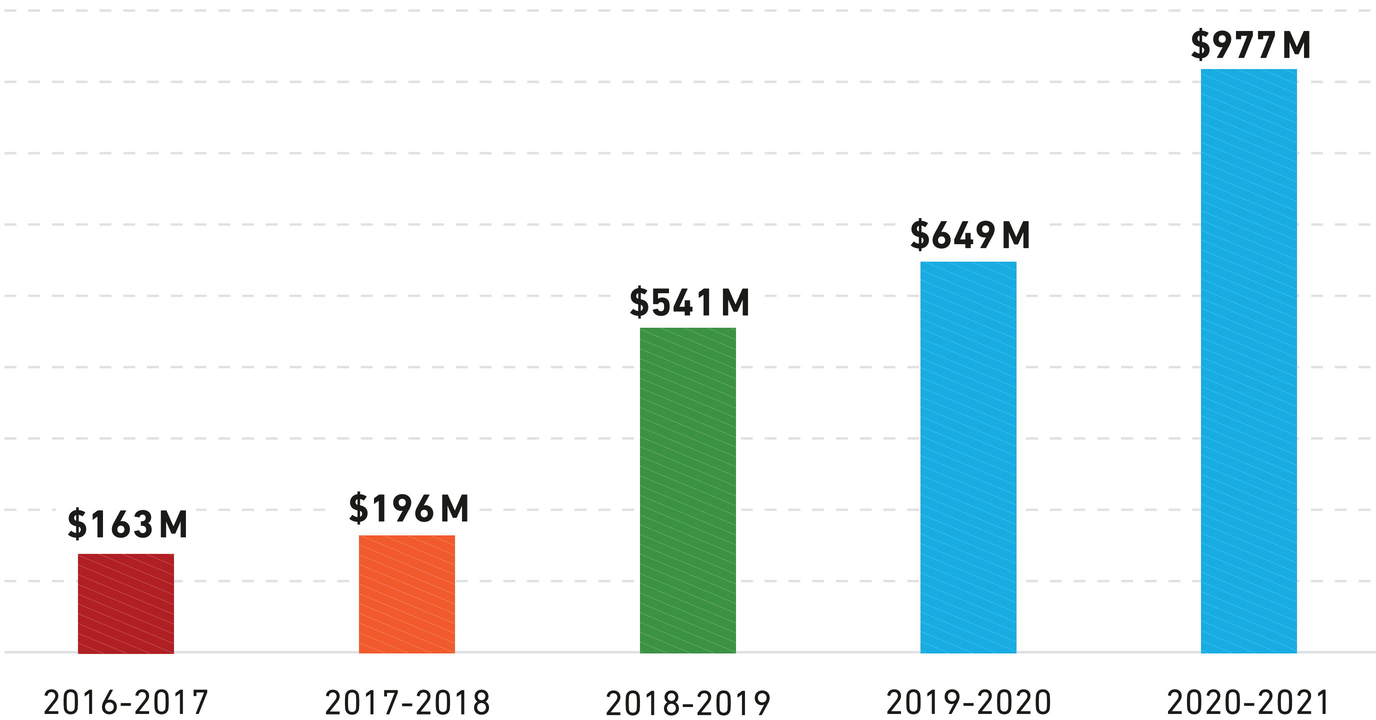
GHG credit allocation options, per barrel produced, 2015



Source: Sarah Dobson *et al.*, *The Ground Rules for Effective OBAs: Principles for Addressing Carbon-Pricing Competitiveness Concerns through the Use of Output-Based Allocations*, School of Public Policy Research Paper, Vol. 10:17, University of Calgary, June 2017, p. 13.

Figure 2-2

Carbon tax revenues from Alberta's Climate Change Emissions Management Fund, 2016-2017 to 2020-2021 (Millions of $)



Note: The figure for 2018-2019 is an estimate, and the figures for 2019-2020 and 2020-2021 are targets.
Source: Government of Alberta, *Fiscal Plan - Budget 2018: A recovery built to last*, p. 144.

Change (UNFCCC) and to the 1997 Kyoto Protocol (which came into force in 2005 and which Canada left in 2011).[96]

The carbon tax regimes now in force across Canada ignore that carbon emissions are first and foremost a consumption problem.

Carbon taxes can be set up in many ways. The World Bank wrote a whole book about the different ways to establish a carbon tax.

1. Carbon taxes can be raised at the *production level*, or at the *consumption level*, in which case the tax is paid by the party consuming carbon-containing goods (either directly, or indirectly if fossil energies were used during the manufacturing process).
2. A jurisdiction which imposes carbon taxes on its constituents can attempt—or not—to protect itself from the phenomenon of carbon intensive industries leaving for a less stringent jurisdiction (carbon leakage) and/or attempt to block the importation of goods from other jurisdictions with less severe carbon taxes.
3. There are two types of carbon taxes: Plain carbon taxes—or levies—and auctioned or traded carbon emissions permits. Auctions or carbon emissions trading can be done at the local (i.e., within a province), national, or international level.
4. The emissions level (i.e., the baseline or benchmark) above which an emitter must pay the tax or acquire emissions permits can vary.[97]

At first glance, the difference between the various options listed above may appear limited, but the system

96. "Canada pulls out of Kyoto Protocol," *CBC News*, December 12, 2011.

97. World Bank Group, *Carbon Tax Guide: A Handbook for Policy Makers*, March 2017, pp. 29-40.

chosen can have a major impact on the economy of a jurisdiction.

Production Level vs. Consumption Level

When the government of Brian Mulroney introduced the Goods and Services Tax in 1991, the tax replaced the former Manufacturer's Sales Tax, which was perceived as hindering manufacturers' capacity to export competitively. This consideration is absent from all of Canada's carbon taxes. Taxing exported products will result in our exports being less competitive. Also, allowing imports from jurisdictions not subject to a carbon tax gives them an unfair advantage over our local industries. That is why, prior to the introduction of the federal carbon tax in 2018, the federal government announced reduced carbon limits for large emitters facing competition.[98] These firms—or facilities—known as Energy-Intensive, Trade-Exposed (EITE) firms, or sometimes Carbon-Intensive Trade-Exposed (CITE) firms, often targeted for their large CO_2 emissions, are the most vulnerable to a production-based carbon tax.[99]

Essentially, the UK, and Europe in general, are exporting their CO_2 emissions to the BRIC and other developing countries, as well as to resource-rich countries.

The carbon tax regimes now in force across Canada ignore a few realities: A paramount consideration that they ignore is that carbon emissions are first and foremost a consumption problem. Second, while companies don't vote, they may move to another jurisdiction, which is known as carbon leakage.[100] Third, Canada is a trading nation and does not live in isolation.

Production-based accounting of carbon emissions was enshrined in the Kyoto protocol.[101] Under the protocol, industrialized countries committed to reducing their carbon emissions.[102] The production-based carbon accounting scheme adopted applied essentially to industrialized countries, which were favoured by it. Over 100 developing countries, including China and India, were exempted from the treaty.[103] These countries would have been penalized by production-based carbon accounting. However, since they were not covered by the protocol, they had nothing to complain about. For most developing countries, including BRIC countries (Brazil, Russia, India and China), an accounting framework based on consumption would be advantageous.[104] The same logic applies to resourced-based economies, such as Canada's, and can explain why Canada withdrew from the Kyoto protocol in 2011. Conversely, production-based accounting leads to carbon leakage and favours countries, such as most European countries,[105] which are de-industrializing. Different authors have measured the impact of this de-industrialization: One author estimates that Europe's CO_2 consumption exceeded it production by 20% to 25% at the end of the 2000s.[106] The late David MacKay from the University of Cambridge, in his book *Sustainable Energy – Without the Hot Air*, demonstrated that once CO_2 embedded in imports is considered, average emissions per capita in the UK were far higher than indicated by governmental statistics.[107] Professor Dieter Helm of Oxford University and his colleagues found that in 2003, if emissions were calculated on a consumption basis, they would jump by over 72% compared to the UNFCCC method.[108]

The impact that over-regulating local production has had on the United Kingdom economy is illustrated by the case of the former Alcan Aluminium, now part of Rio Tinto, which used to operate an aluminum smelter at Lynemouth, England. The smelter had been commissioned in 1974 and used power from a coal-fired plant located nearby which, over the years, burned local and imported coal.[109] In 2010, the European Court of Justice ruled that the Lynemouth plant was contravening the European Large Combustion Plant Directive. This is one

98. Greg Quinn, "Canada Loosens Carbon Limit for Big Emitters Facing Competition," Bloomberg, August 1st, 2018.

99. The Conference Board of Canada, *The Cost of a Cleaner Future: Examining the Economic Impacts of Reducing GHG Emissions*, Report, September 2017, pp. v and 15.

100. Germain Belzile and Mark Milke, *op. cit.*, footnote 79.

101. Baptiste Boitier, "CO_2 emissions production-based accounting vs. consumption: Insights from the WIOD databases," Paper presented at the Final WIOD Conference: Causes and Consequences of Globalization, Groningen, The Netherlands, April 24-26, 2012.

102. United Nations Framework Convention on Climate Change, "Fact Sheet: The Kyoto Protocol," February 2011.

103. CNN, "Kyoto Protocol Fast Facts," March 21, 2018.

104. Baptiste Boitier, *op. cit.*, footnote 101, p. 8.

105. *Ibid.*

106. *Ibid.*, p. 8.

107. David MacKay, *Sustainable Energy – Without the Hot Air*, UIT Cambridge Ltd, 2009, section III, technical chapters, H Stuff II, pp. 322-326.

108. Dieter Helm, Robin Smale, and Jonathan Philipps, *Too Good to Be True? The UK's Climate Change Record*, New College, Oxford, December 10, 2007, p. 24.

109. David Merlin-Jones, "The closure of the Lynemouth aluminium smelter: An analysis," Civitas, April 2012, pp. 3-4.

of the main factors that led to the plant being shut down in 2012.[110] But this has not solved any problem. Today, China produces more than half of the world's aluminum, and coal is the country's dominant power source.[111] Except for the output of a tiny smelter located in Scotland, all aluminum used in the United Kingdom is imported.[112]

Essentially, the UK, and Europe in general, are exporting their CO_2 emissions to the BRIC and other developing countries, as well as to resource-rich countries. This allows their governments to claim that they are reducing their CO_2 emissions.

A 2015 report on Australia, which has an economy similar in size to Canada's,[113] states:

> By failing to explicitly recognise emissions associated with international trade, production-based emissions measures provide an incomplete picture of the drivers of emissions and the effectiveness of action to reduce emissions. A production-based emissions target which does not encompass all centres of production creates a risk of 'carbon leakage'. Carbon leakage is defined by the Intergovernmental Panel on Climate Change (IPCC) as "the increase in CO_2 emissions outside the countries taking domestic mitigation action…" More broadly, carbon leakage can refer to the shifting of productive activity from countries with emissions reduction targets to those without targets. To the extent that production moves to countries with more emissions-intensive economies, carbon leakage may lead to a net increase in global emissions.[114]

This is exactly the situation which Canada faces. The report also shows that Canada is neither a net carbon exporter nor an importer, as can be seen in Figure 2-3. What this leaves out is that on the one hand, we export carbon in our energy products and natural resources, and on the other hand, we import carbon embedded in finished goods.

The same mismatch between carbon producing and carbon consuming jurisdictions can also be observed between Canadian provinces. Sarah Dobson and G. Kent Fellows from the University of Calgary's School of Public Policy measured the relative level of carbon production vs. carbon consumption for each province. As might be expected, Alberta and Saskatchewan produce more carbon than they consume, and are therefore penalized by the carbon tax methodology followed in Canada (see Figure 2-4). Conversely, British Columbia, Ontario, and Quebec all consume more carbon than they produce, and are favoured by Canada's carbon tax methodology.[115]

Carbon Border Taxes

The authors do not propose that Canada impose a carbon border tax. However, in the debate about taxing carbon emissions, the problem of taxes making Canada's exports uncompetitive and encouraging non-taxed imports has to be addressed.

To the extent that production moves to countries with more emissions-intensive economies, carbon leakage may lead to a net increase in global emissions.

If all countries were implementing similar carbon tax schemes simultaneously, they would be easier to administer. In reality, a carbon tax must take borders into account: When your neighbour and principal trading partner (the United States),[116] as well as one of your main providers of finished goods (China), do not have similar carbon tax schemes, you must adjust your policy. In order to work properly, a Canadian carbon scheme would have to include adjustments for imports and exports: Imported goods would have to be taxed at the same level charged to local producers, and exported goods would have to be exempted in order to allow local companies to compete on a level playing field. When dealing with imports from a jurisdiction which imposes similar taxes, these border adjustments could be

110. *Ibid.*, pp. 6-7.

111. T. J. Brown *et al.*, *World Mineral Production: 2012-2016*, British Geological Survey, 2018, p. 3; Jude Clemente, "Coal Isn't Dead. China Proves It," *Forbes*, January 23, 2019.

112. Wikipedia, List of Aluminium Smelters.

113. Australia's GDP was US$1,323.42 billion in 2017, while Canada's was US$1,653.04 billion. Trading Economics, Canada GDP; Trading Economics, Australia GDP.

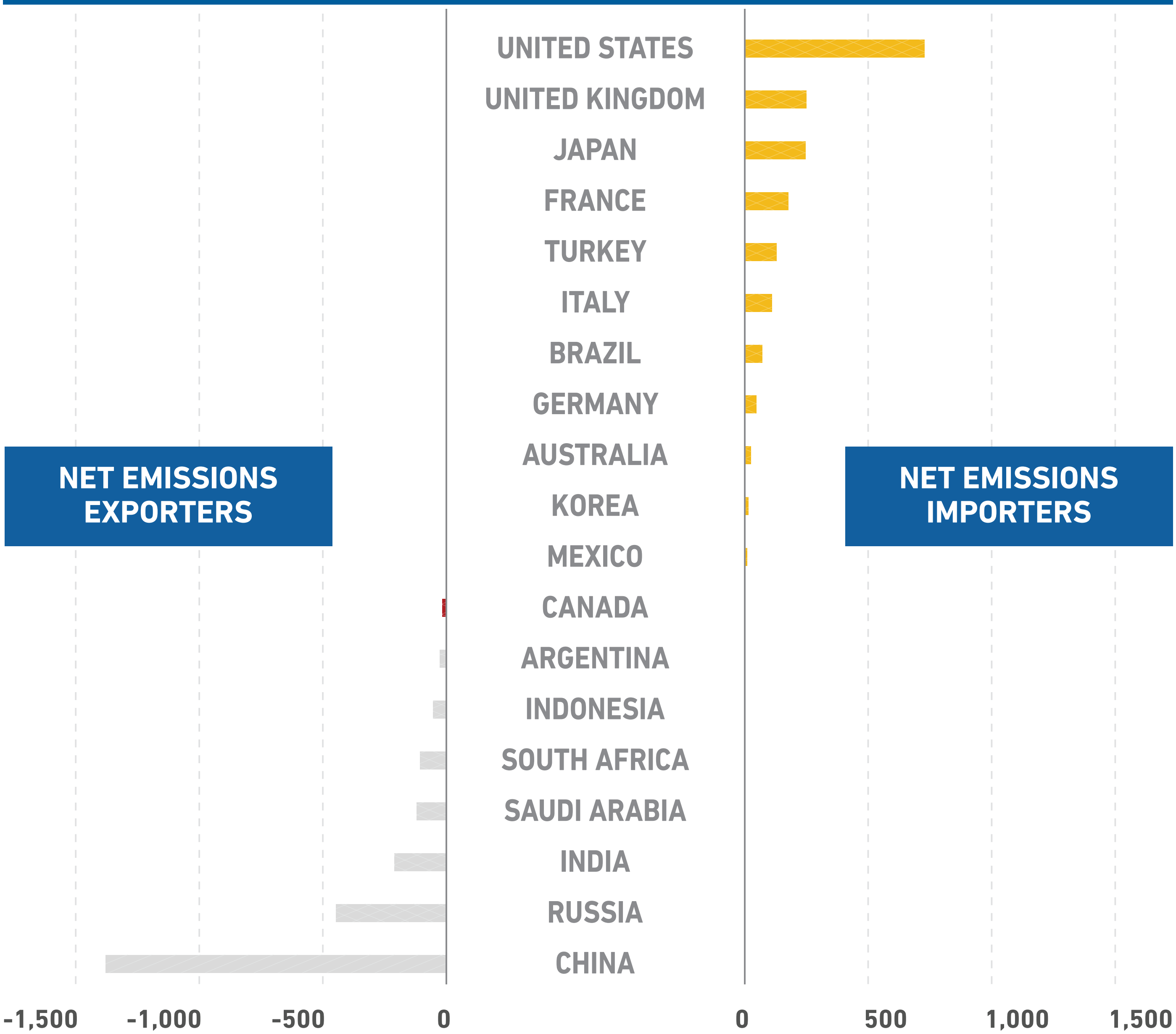
114. Deloitte, *Consumption-based carbon emissions*, *Carbon analytics: Australia's performance in the G20*, Deloitte Access Economics, August 2015, pp. 9-10.

115. Sarah Dobson and G. Kent Fellows, "Big and Little Feet Provincial Profiles: Alberta," SPP Communiqué, Volume 9:4, September 2017; Sarah Dobson and G. Kent Fellows, "Big and Little Feet Provincial Profiles: British Columbia," SPP Communiqué, Volume 9:3, September 2017; Sarah Dobson and G. Kent Fellows, "Big and Little Feet Provincial Profiles: Saskatchewan," SPP Communiqué, Volume 9:5, September 2017; Sarah Dobson and G. Kent Fellows, "Big and Little Feet Provincial Profiles: Ontario," SPP Communiqué, Volume 9:7, September 2017; Sarah Dobson and G. Kent Fellows, "Big and Little Feet Provincial Profiles: Quebec," SPP Communiqué, Volume 9:8, September 2017.

116. Statistics Canada, Table: 12-10-0011-01, International merchandise trade for all countries and by Principal Trading Partners, monthly (x 1,000,000).

Figure 2-3

G20 countries' net energy emissions balance, 2011, $MtCO_2$



Source: Deloitte, *Consumption-based carbon emissions, Carbon analytics: Australia's performance in the G20*, Deloitte Access Economics, August 2015, p. 13.

lifted. Introducing border adjustments is a policy option put forward after the Paris Agreement, since the difference in carbon legislation leads to carbon leakage as carbon-intensive industries are incentivized to move to other jurisdictions which do not play by the same rules.[117]

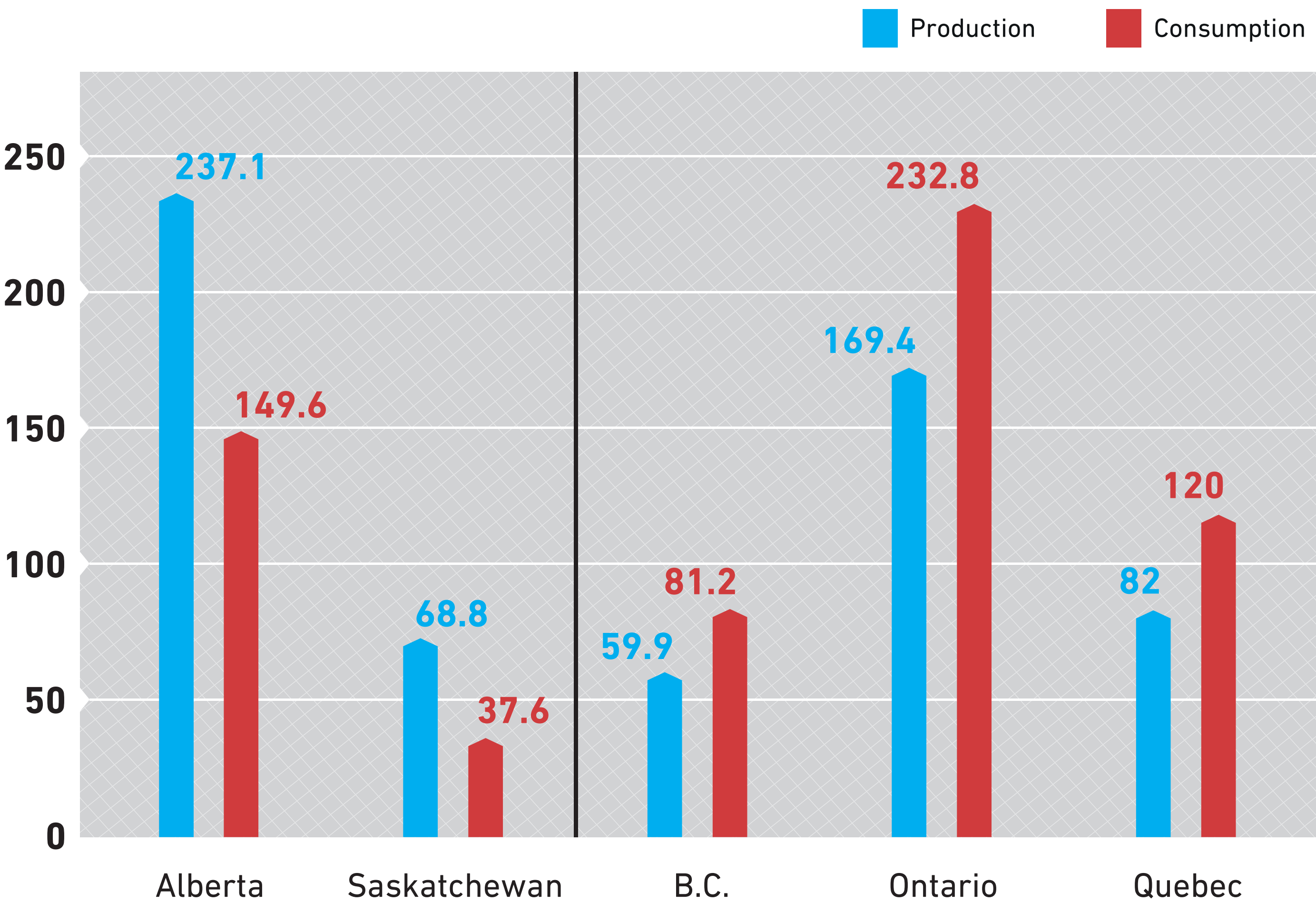
The notion of carbon border adjustments was brought up by the Conference Board of Canada in their report entitled *The Cost of a Cleaner Future: Examining the Economic Impacts of Reducing GHG Emissions.*[118] The report states: "Given that Canada's most important trading partner—the United States— is unlikely to adopt

117. Aaron Cosbey, "The Paris Climate Agreement: What Implications for Trade?" *Trade Hot Topics*, The Commonwealth, No. 129, 2016, p. 3.

118. The Conference Board of Canada, *op. cit.*, footnote 99, pp. 12-13.

Figure 2-4

Total production and consumption emissions, by province, megatonnes (Mt) of CO_2e ($MtCO_2e$), 2011



Sources: Sarah Dobson and G. Kent Fellows, "Big and Little Feet Provincial Profiles: Alberta," SPP Communiqué, Volume 9:4, September 2017, p. 2; Sarah Dobson and G. Kent Fellows, "Big and Little Feet Provincial Profiles: British Columbia," SPP Communiqué, Volume 9:3, September 2017, p. 2; Sarah Dobson and G. Kent Fellows, "Big and Little Feet Provincial Profiles: Saskatchewan," SPP Communiqué, Volume 9:5, September 2017, p. 2; Sarah Dobson and G. Kent Fellows, "Big and Little Feet Provincial Profiles: Ontario," SPP Communiqué, Volume 9:7, September 2017, p. 2; Sarah Dobson and G. Kent Fellows, "Big and Little Feet Provincial Profiles: Quebec," SPP Communiqué, Volume 9:8, September 2017, p. 2.

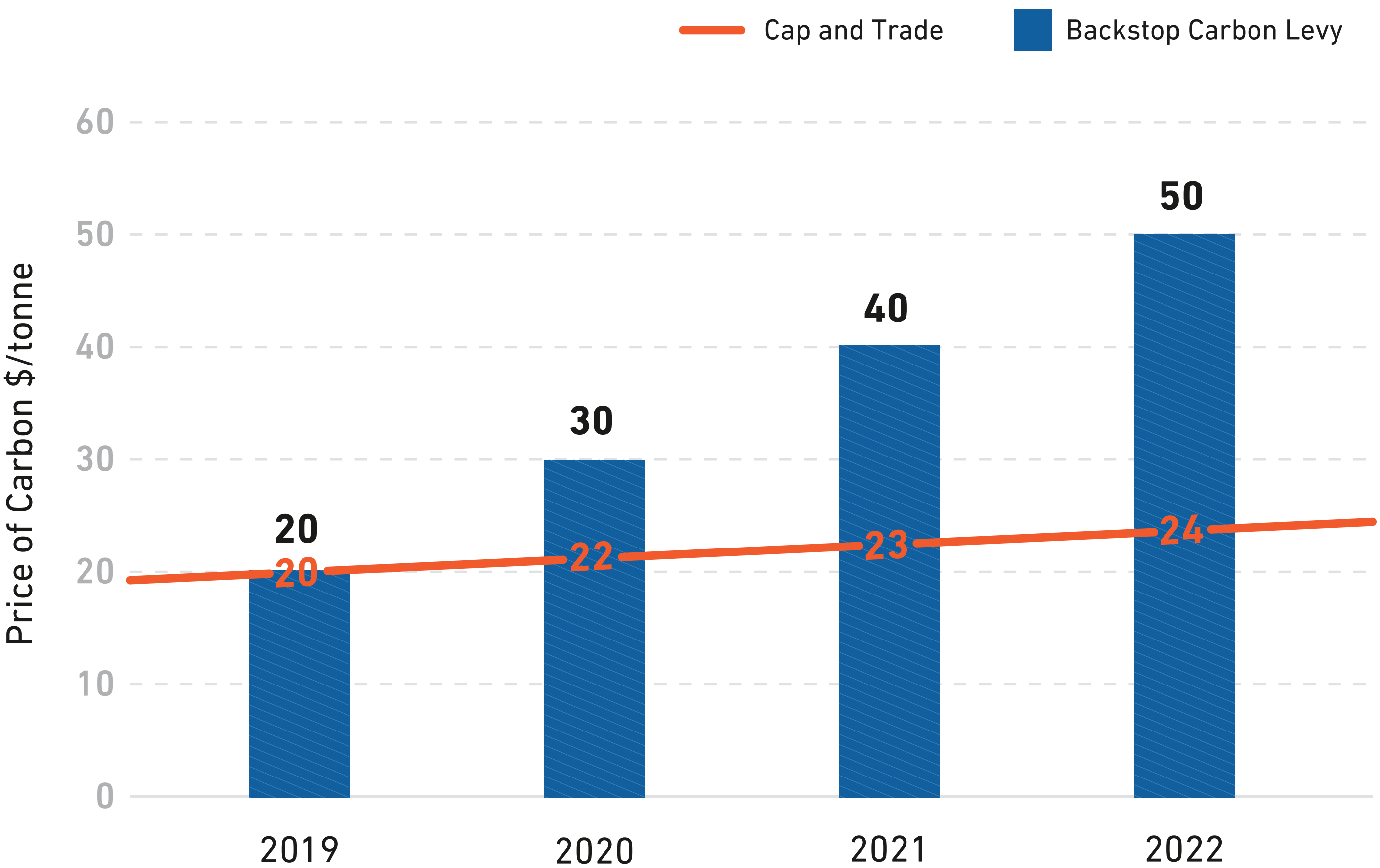
carbon taxes any time soon, and because carbon emissions are embedded in virtually all goods that are imported, the Canadian government might consider applying tariffs to imported goods so as not to favour those over domestic products that are taxed for their use of GHGs. In the carbon leakage literature, these are referred to as 'border adjustments.'" A carbon tax could be structured in a similar way to the Goods and Services Tax (GST), on the one hand taking the form of a carbon-added tax on end users instead of the proposed \$50 carbon tax on production, and on the other hand having imported goods face a levy at the border and exported goods be tax-exempt.[119]

In the above-mentioned Conference Board report, it is assumed that hydrocarbon producers would be exempted from a potential carbon tax on their exported goods: "[B]ecause we assume that the tax will be levied when fuels are combusted within our borders, energy producers who export their goods will not be subject to

119. Luc Vallée and Jean Michaud, "The right way to tax carbon: Follow the GST model," *Financial Post*, December 19, 2016; Luc Vallée and Jean Michaud, "When it comes to taxing carbon, Canada has it exactly backward," *Financial Post*, June 14, 2017.

Figure 2-5

Comparison of cap-and-trade price and federal carbon tax, $ per tonne



Source: Financial Accountability Office of Ontario, *Cap and Trade: A Financial Review of the Decision to Cancel the Cap and Trade Program*, Fall 2018, p. 16.

the carbon tax, since combustion will occur in another jurisdiction."[120] In fact, even if the best policy were a full border-adjustment system, a politically easier one could be to implement one half of it, by de-taxing exports, as the GST does, without, however, taxing GHG emissions contained in imported goods.

In February 2017, a group of U.S. intellectuals close to the Republican Party introduced, under the supervision of the Climate Leadership Council, "The Conservative Case for Carbon Dividends."[121] Among the main promoters of the scheme are James A. Baker III, Henry M. Paulson Jr., and George P. Shultz—all former Secretaries of the Treasury—as well as Martin Feldstein and N. Gregory Mankiw—well-known economists.

Their proposal includes:

1. A gradually increasing carbon tax
2. Carbon dividends (returning 100% of carbon tax proceeds to households)
3. Border carbon adjustments
4. Significant regulatory simplification

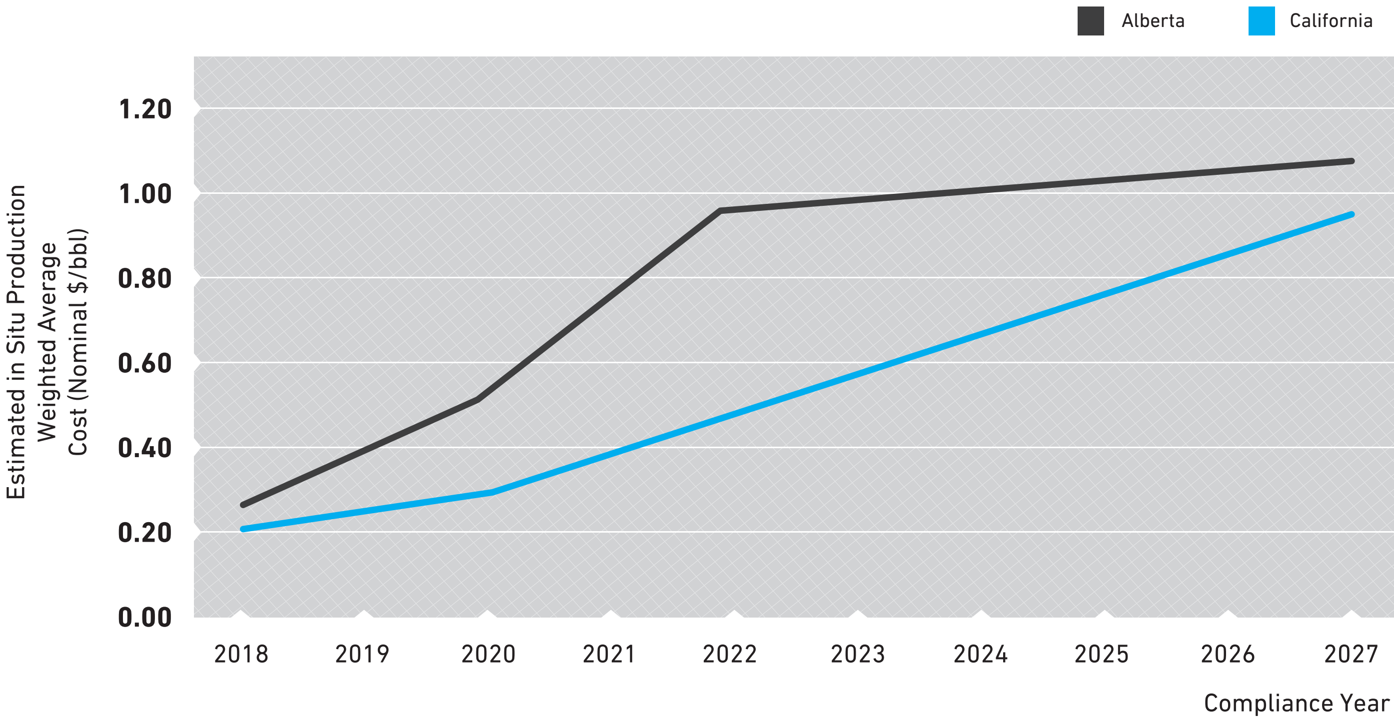
As might be expected, Alberta and Saskatchewan produce more carbon than they consume, and are therefore penalized by the carbon tax methodology followed in Canada.

120. The Conference Board of Canada, *op. cit.*, footnote 99, p. 13.

121. James A. Baker, "The Conservative Case for Carbon Dividends," Climate Leadership Council, February 2017.

Figure 2-6

Alberta vs. California/Quebec climate policies comparison



ASSUMPTIONS:

ALBERTA
- CO_2 price = $30/t 2018-2020, $40/t in 2021, $50/t thereafter

CALIFORNIA
- Analyzed California policy with Alberta in situ facility data for establishing benchmark
- CO_2 price starting at $19.40 CAD and increasing by $1.50 per year thereafter (auction floor price)

Source: (2.36 page 5) CAPP, *2018 Economic Report Series: Competitive Climate policy, Supporting Investment and Innovation*, 2018, p. 5.

While the carbon tax systems now in effect in Canada generally include items 1 and 2, they lack items 3 and 4 which would protect local industries and simplify their operation.

As was shown earlier, it is pointless to shut down a CO_2 emitting facility if the goods it produces are to be later imported or produced in another jurisdiction which does not have as strict pollution-control measures. Reduced carbon limits for large emitters facing competition are a patch on a flawed system. If we really want to reduce carbon emissions, we need to consider the whole life cycle of all energy sources and of goods consumed, from cradle to grave, and what the available alternatives are.

Imposing border adjustments on imported goods, as mentioned by the Conference Board, would not be easy.[122] Some goods, such as hydrocarbons, cement, steel, and aluminium, which are highly carbon intensive, would be easier to identify and tax. For complex fabricated products, simple estimates could be used, as suggested

When your neighbour and principal trading partner (the United States), as well as one of your main providers of finished goods (China), do not have similar carbon tax schemes, you must adjust your policy.

122. The Conference Board of Canada, *op. cit.*, footnote 99, p. 13.

Table 2-1

Carbon emissions by jurisdiction, megatonnes of CO_2-equivalent emissions						
Jurisdiction	**1990 Emissions**	**2005 Emissions**	**2012 Emissions**	**2017 Emissions**	**2020 Target Emissions**	**Stated Emissions-Reduction Target, 2020**
California	437	486	450	429*	437	At 1990 levels
Quebec	86	86	80	78	69	20% below 1990 levels
Ontario	180	204	169	159	153	15% below 1990 levels
British Columbia	52	63	60	62	43	33% below 2007 levels (≈17% below 1990 levels)
Alberta	173	231	261	273		

Note: The 2017 figure for California is in fact for 2016.
Source: Government of Canada, "Greenhouse gas sources and sinks: executive summary 2019," April 18, 2019; California Air Resource Board, 2018 Edition California Greenhouse Gas Inventory for 2000-2016 — by IPCC Category," 2018; California Air Resources Board, California Greenhouse Gas Inventory for 1990-2004 — By IPCC Category, November 19, 2007; for the stated or inferred emission targets, see C.D. Howe, "Carbon Copies: The Prospects for an Economy-wide Carbon Price in Canada," Energy and Natural Resources Policy, E-Brief, September 15, 2016, p. 5.

by David Mackay for the United Kingdom.[123] It is better to be approximately right than exactly wrong.

Yet there is a strong argument against carbon border taxes in that they impinge upon free trade. It is believed that a well-designed border adjustment system could comply with international trade regulations and be accepted by the WTO.[124] That being said, a unilateral border-adjustment system, even if good in theory, could create a backlash, and might even lead to a trade war with our trading partners. Ideally, such a system would have to be implemented internationally in order to work without running the risk of damaging international trade.

Finally, a carbon tax should not be the pretext for a cash grab by the government. This means that any carbon tax should be compensated by an equivalent reduction of other taxes, preferably the ones that are the most destructive in economic terms: corporate taxes on profits and personal income taxes, for example.

Carbon Tax vs. Cap and Trade

The federal government and all Canadian provinces except Quebec have opted for plain carbon taxes or levies, by which an emitter must pay a certain sum of money for each tonne of carbon dioxide it produces. Some governments, such as Alberta, allow a producing entity to buy carbon credits from another *local* entity that has earlier reduced its emissions. The Quebec cap-and-trade system—an international scheme also involving California, which Ontario briefly joined—allows an entity to purchase carbon credits outside Quebec borders, in this case from Californian entities having reduced their carbon emissions below their benchmark.[125]

Any carbon tax should be compensated by an equivalent reduction of other taxes, preferably the ones that are the most destructive in economic terms.

The size of the market where an entity can purchases carbon credits—either outright or through auctions or a

123. David MacKay, op. cit., footnote 107, pp. 322-323.

124. Stavros Afionis *et al.*, "Consumption-based carbon accounting: Does it have a future?" *WIREs Climate Change*, 2017, pp. 11-13.

125. Germain Belzile and Mark Milke, *op. cit.*, footnote 79.

carbon emissions trading scheme—matters. This can be done at the local (that is, within a province), national, or international level.

As can be seen in Figure 2-5, drawn from the Financial Accountability Office of Ontario, the price of carbon credits under the Quebec-California cap-and-trade program is expected to remain below the Canadian federal backstop price for many years. Indeed, by 2022, the federal carbon tax is expected to be roughly double the price of credits in Quebec and California.

The same observation holds when comparing the cost of Alberta's climate policies with those of California and Quebec, (see Figure 2-6). By 2022, the projected cost in Alberta is about double what it is in the carbon market between Quebec and California. Again, it is worth noting that Alberta, with its current climate policies, has the highest carbon taxes in North America, and this is projected to continue, unless there is a radical change in policies.

These governments may not want to forego the carbon tax proceeds, but a tonne of carbon dioxide not emitted in Canada or elsewhere in the world has the same impact on the climate.

It makes perfect sense for carbon credits to be cheaper when obtained from a broader market. Table 21 comparing actual and targeted carbon emissions for Alberta, California, Quebec, and a few others shows that emissions in California were—and have remained—much higher than those of Canadian provinces.

California, which used to get a large share of its power from coal,[126] can now sell carbon credits arising from the shutdown of these coal-fired powerhouses to Quebec entities at a much lower price than what would be available should Quebec emitters have to buy them from local sources.

The same logic also applies when acquiring carbon credits on a worldwide scale: We are often told that Scandinavian countries have extremely high carbon taxes. However, while in Norway and Sweden, the carbon tax on gasoline is approximately C$79.70 per tonne (500 Norwegian Crowns)[127] and C$170 per tonne (1,180 Swedish Crowns)[128] respectively, companies do not pay these prices for their emissions. They buy (or sell) carbon credits, whose price has ranged between 5€ and 25€ per tonne the past few years (approximately C$7.51 to C$37.57),[129] through an international scheme approved under the UN Framework Convention on Climate Change (UNFCCC).[130] According to the UNFCCC and the World Bank, "using carbon pricing approaches on a large scale to meet the emission reduction targets […] could reduce the cost of climate change mitigation by 32% by 2030."[131] The UNFCCC was enshrined in the Paris Agreement as Article 6.[132] As a signatory of the Paris Agreement, Canada has de facto endorsed it.

Since Canada has approved a worldwide carbon trading mechanism, which is expected to reduce the cost of carbon credits by nearly a third, our governments—both at the federal and provincial levels—could allow its use. These governments may not want to forego the carbon tax proceeds, but a tonne of carbon dioxide not emitted in Canada or elsewhere in the world has the same impact on the climate. The purpose of a carbon tax should be to reduce carbon emissions, not to raise tax revenues from individuals and companies. Therefore, allowing emitters to use all the tools available to them to achieve the stated goal, at the lowest possible cost, would reduce the adverse economic impact of these policies on the Canadian economy.

126. California Energy Commission –Tracking Progress, "California's Declining Reliance on Coal – Overview," October 2018.

127. UNFCC, "Talanoa-dialogue. Norway," April 2, 2018, p. 4; Bank of Canada, Annual Exchange Rates, 2018.

128. Government Offices of Sweden, Government Policy, Taxes and Tariffs, Sweden's Carbon Tax; Bank of Canada, Monthly Exchange Rates, March 2019.

129. Markets Insider, Commodities, CO_2 European Emission Allowances; Government of Norway, Climate and environment, Climate, Norwegian Carbon Credit Procurement Program; Reuters, "Update 1- Norway plans to sell 46.8 mln EU carbon allowances in 2019 – budget," October 8, 2018.

130. UNFCCC, Regional Collaboration Centres, The CI-ACA Initiative, About Carbon Pricing.

131. *Ibid.*

132. United Nations, *Paris Agreement*, Article 6, 2015, pp. 7-8.

CHAPTER 3

Regulations and Permitting Delays

The Alberta Energy Regulator (AER), which oversees all energy-related activities in Alberta including crude oil, natural gas, and oil sands, as well as coal and pipelines not overseen by the National Energy Board, is generally perceived as a first-class entity. Yet companies operating in the province point to the permitting delays observed as a serious problem; compared to oil and gas producing American states, Alberta is not competitive in this regard.

In light of recent developments affecting the oil and gas industry both directly (lack of pipelines) and indirectly (carbon tax), the government of Alberta should update its vision on the future of the industry. The government of Newfoundland and Labrador issued such an updated plan in early 2018, spelling out a number of realistic objectives to be implemented during the next decade.[133] Since oil sands projects in Alberta are massive long-term projects, the Alberta government should state where it sees the province's oil and gas industry a decade from now.

The next step would be for the government to revisit the responsibilities of its departments with regard to oil and gas operations, namely which ministry is responsible for what and how it affects the industry. Among these are the Ministry of Energy, which includes the department of energy as well as the Alberta Energy Regulator (AER) and the Alberta Petroleum Marketing Commission (APMC) overseeing value added activities in Alberta's petroleum sector; the Ministry of Environment (Alberta Environment and Parks – AEP); and the Ministry of Indigenous Relations (IR).[134] In addition to these ministries, which have a direct say in oil and gas operations, the activities of other ministries, such as the Ministry of Municipal Affairs—via municipal property taxes—may also impact the competitiveness of the province's oil and gas sector. Alberta should adopt a holistic approach in order to streamline its vision and regulations regarding the oil and gas industry.

133. Government of Newfoundland and Labrador, *The Way Forward: Advance 2030 – A Plan for Growth in the Newfoundland and Labrador Oil and Gas Industry*, February 2018.

134. The AER was created in 2013 by the *Responsible Energy Act*. It is 100% funded by industry and is authorized to collect funds through an administrative fee levied on energy development projects and activities. See Alberta Energy, About; Alberta Energy Regulator, Providing Information, About the AER, Who we are.

Regulatory Efficiency and Effectiveness

Needless to say that given their complexity and potential environmental impact, oil and gas operations must be regulated. However, for an industrial sector to be competitive, it is necessary, from time to time, to benchmark its performance and procedures with those of its main competitors.

That is just what the Canadian Association of Petroleum Producers (CAPP) did in a September 2018 report.[135] Its evaluation of the Alberta Energy Regulator is quite harsh: "The province's current regulatory environment has contributed to the erosion of investor confidence in the oil and natural gas industry. Alberta's regulatory framework is fraught with process inefficiencies, lengthy approval timelines, and escalating regulatory costs that, combined, increase costs and generate investor uncertainty in Alberta's regulatory system."[136]

Companies operating in the province point to the permitting delays observed as a serious problem; compared to oil and gas producing American states, Alberta is not competitive in this regard.

Long approval timelines for projects are a particular headache. The report compares Target Approval Timelines for well drilling permitting in Alberta versus neighbouring Canadian provinces and some U.S. jurisdictions (see Table 3-1).

The first thing to note is that in no case does a firm operating under a full Alberta non-routine well-licensing process (and in particular in the event that statements of concern (SOCs) are filed) have an advantage versus other jurisdictions. In the best of cases (routine), timelines are similar to those in other Canadian provinces and on U.S. federal land. When applying to drill on U.S. freehold land, permitting is always months faster—Texas being the friendliest state.

Table 3-2, showing the number of applications submitted in Alberta for wells and facilities in recent years, is

135. Canadian Association of Petroleum Producers, *UPDATE: A Competitive Policy and Regulatory Framework for Alberta's Upstream Oil and Natural Gas Industry*, September 2018.

136. *Ibid.*, p. 26.

Table 3-1

Target approval timelines, 2017

Alberta	B.C.	Saskatchewan	U.S. Federal	U.S. Freehold – Texas	U.S. Freehold – Other
Non-Routine with SOC*: 198-220+ days Non-Routine: 116-144 days Routine: 79-119 days	90-128 days (up to 130-day advantage)	72-120 days (up to 148-day advantage)	120 days (up to 100-day advantage)	< 30-60 days (up to 190-day advantage)	90 days (up to 130-day advantage)

Note: While these timelines provide estimates based on recent operator data with respect to applications involving Statements of Concern (SOCs), in some cases SOCs may result in even more protracted timelines. An SOC is a request to be consulted submitted by an individual with regard to a company's proposed energy development. See Alberta Energy Regulator, Protecting What Matters, Giving Albertans a Voice, Statement of Concern.
Source: Canadian Association of Petroleum Producers, *UPDATE: A Competitive Policy and Regulatory Framework for Alberta's Upstream Oil and Natural Gas Industry*, September 2018, p. 28.

In no case does a firm operating under a full Alberta non-routine well-licensing process have an advantage versus other jurisdictions. When applying to drill on U.S. freehold land, permitting is always months faster.

also telling. Between 2014 and 2017, the proportion of facilities and wells characterized as non-routine due to participant involvement (PI) has doubled. This means that during this period, requests by stakeholders (local residents, municipalities, and indigenous communities) to be heard before a project is approved have doubled in relative terms (and also increased in absolute terms). At the same time, the total numbers of applications for both wells and facilities fell by over 40%. In a nutshell, the pitfalls of social licence, by giving too much room to various groups, seem to have affected applications for facilities and wells, and are likely to be fuelling a loss of confidence in the existing process due to its unpredictability.[137]

Extraordinary timelines also affect oil sands projects. As the CAPP report notes, "a typical in situ development in Alberta has a best-case approval timeline from the start of consultation through to the start of construction of four to six years, and could require more than 560 separate, and potentially sequential, regulatory approvals, authorizations or permits under more than 15 distinct regulations or acts."[138]

Late in 2017, the Alberta Energy Regulator introduced the new "Integrated Decision Approach" (IDA) for oil and gas projects, which makes use of OneStop, a digital platform designed to ease the processing of applications.[139] The new approach covers all activities over the life of an oil and gas project from construction and operation through to abandonment and reclamation. It is still in its infancy. It has been road-tested on a few projects and is being gradually implemented, but it will not be fully implemented before 2021.[140]

The Way Forward

Regulatory requirements generally drive the critical path for oil and natural gas project development. Long or uncertain timelines for approvals and permitting compound the inherent risk and uncertainty of any project. Streamlining project approvals and regulatory timelines is first and foremost a task for the province's legislature. Given the multiple other challenges facing the Albertan

137. Youri Chassin and Germain Belzile, "The Three Pitfalls of Social Licence," Economic Note, MEI, March 2017.

138. Canadian Association of Petroleum Producers, *op. cit.*, footnote 135, pp. 26-27.

139. Alberta Energy Regulator, Regulating Development, Project Application, Integrated Decision Approach; Esri Canada, "Alberta Energy Regulator Lauded for Streamlining Regulatory Process with GIS," News Release, September 19, 2018.

140. James Wood, "One-stop software tool for oilpatch to cut approval time, costs: NDP," *Calgary Herald*, August 22, 2018; "Alberta's streamlined regulatory regime saves energy industry $140M, minister says," *CBC News*, August 21, 2018.

Table 3-2

Well and facility applications submitted in Alberta, % of total (closed and pending)								
	FACILITIES				**WELLS**			
Application Year	**Routine**	**Non-Routine Technical**	**Non-Routine PI**	**Total**	**Routine**	**Non-Routine Technical**	**Non-Routine PI**	**Total**
2014	57%	35%	8%	**2,980**	94%	3%	4%	**10,498**
2015	55%	36%	9%	**1,721**	92%	2%	6%	**5,833**
2016	61%	26%	13%	**1,231**	93%	2%	5%	**5,153**
2017	54%	31%	15%	**1,697**	90%	2%	8%	**6,298**

Note: PI = participant involvement, i.e., a consultation with stakeholders (local residents, municipalities, and indigenous communities) about proposed energy developments. See Alberta Energy Regulator, "Participant Involvement Initiative: Shaping Future Conversations," pp. 4-6.
Source: Canadian Association of Petroleum Producers, *UPDATE: A Competitive Policy and Regulatory Framework for Alberta's Upstream Oil and Natural Gas Industry*, September 2018, p. 29.

oil and gas industry over which the province's legislature has little to no power, it would make plain sense to attempt to *cut by half* the timeline for major projects, in order to be as attractive as American producing states. It is an existential question, and would help maintain investor confidence and keep Alberta competitive.

While it is imperative to protect the environment, it would be advisable to remove those requirements which do not serve a purpose anymore, given the evolution of the industry, and to rationalise municipal taxes across the province. The current system generates uncertainty and complexity for energy projects.

Requests by stakeholders to be heard before a project is approved have doubled in relative terms (and also increased in absolute terms). At the same time, the total numbers of applications for both wells and facilities fell by over 40%.

CHAPTER 4

Energy Corridors and First Nations Partnerships

In a book published posthumously in 2017, Jim Prentice (with co-author Jean-Sébastien Rioux, now at the University of Calgary) proposes the idea of energy corridors.[141] The concept had also been brought up in a presentation to the Senate of Canada on September 21, 2016 by Michael Priaro, a professional engineer, member of the Association of Professional Engineers and Geoscientists of Alberta.[142]

An earlier example of such a corridor had been proposed in the 1970s in the form of a pipeline corridor from the Mackenzie River delta to Alberta and onward to the United States. The project was later revived in the early 2000s as a joint venture between Imperial Oil, ConocoPhillips Canada, ExxonMobil Canada, and the Aboriginal Pipeline Group, and was called the Mackenzie Gas Project. This project was later cancelled following the price drop for natural gas across North America due to fracking.[143]

Both Prentice and Priaro insist that pipeline projects to Canada's West Coast be carried out in coordination with the First Nations whose territories would be crossed by the pipeline. While Priaro insists on bunching oil and gas pipelines in the same corridor, Prentice states that coastal First Nations be financial partners in these projects: "Canada will never be able to export its oil or natural gas into the Asia Pacific Basin unless it is by way of pipelines and port facilities that are owned, at least in part, by First Nation partners."[144]

As Prentice and Rioux mentioned, "West coast access, for both oil and natural gas, is a national imperative for our country. Canada will remain a satellite supplier of energy to the United states unless we can sell our oil and gas into the global market place at global prices."[145]

In a report presented in 2015 to the Honorable Bernard Valcourt, Douglas R. Eyford, who had been appointed by the federal government, encouraged the formation of tripartite energy groups involving both levels of government and First Nations.[146] The Canadian Energy Pipeline Association was mentioned as an interested stakeholder.[147]

The presence of First Nations in the development of energy resources and energy corridors is now a fact of life.[148] Founded in 1987 by First Nations whose territories are located in oil and gas producing regions, the Indian Resource Council (IRC) now represents over 200 First Nations across the country. In 1996, the IRC and Indian Affairs and Northern Development Canada (now Crown-Indigenous Relations and Northern Affairs) were signatories to a Memorandum of Understanding to create and manage the Indian Oil and Gas Canada Co-Management Board (IOGC Board).[149]

Founded in 1987 by First Nations whose territories are located in oil and gas producing regions, the Indian Resource Council (IRC) now represents over 200 First Nations across the country.

The IRC is promoting the Linear Project Valuation Methodology, a procedure to help with evaluation and avoid having to reinvent the wheel each time a new project surfaces.[150] The IRC and its President and CEO, Stephen Buffalo, support, under certain conditions, oil and gas production[151] and the construction of pipelines as a tool for improving the livelihood of all First Nations. The organization has been quite vocal lately in its interest in the Trans Mountain pipeline.[152]

141. Jim Prentice and Jean-Sébastien Rioux, *Triple Crown: Winning Canada's Energy Future*, HarperCollins Publishers, 2017.

142. Senate of Canada, "The Standing Senate Committee on Transport and Communications: Evidence," 42nd Parliament, 1st Session, Calgary, September 21, 2016.

143. James H. Marsh and Nathan Baker, "Mackenzie Valley Pipeline Proposals," *The Canadian Encyclopedia*, March 21, 2018; Germain Belzile and Alexandre Moreau, *The First Entrepreneurs: Natural Resource Development and First Nations*, Research Paper, MEI, November 2018, pp. 26-27.

144. Jim Prentice and Jean-Sébastien Rioux, *op. cit.*, footnote 141, p. 213.

145. *Ibid.*, p. 226.

146. Douglas R. Eyford, *A New Direction: Advancing Aboriginal and Treaty Rights*, Government of Canada, Aboriginal Affairs and Northern Development Canada, 2015, pp. 42-43.

147. *Ibid.*, p. 83.

148. Germain Belzile and Alexandre Moreau, *op. cit.*, footnote 143.

149. Indian Resource Council, About, Indian Resource Council, Membership; Indian Resource Council, Organization, IOGC Co-Management Board.

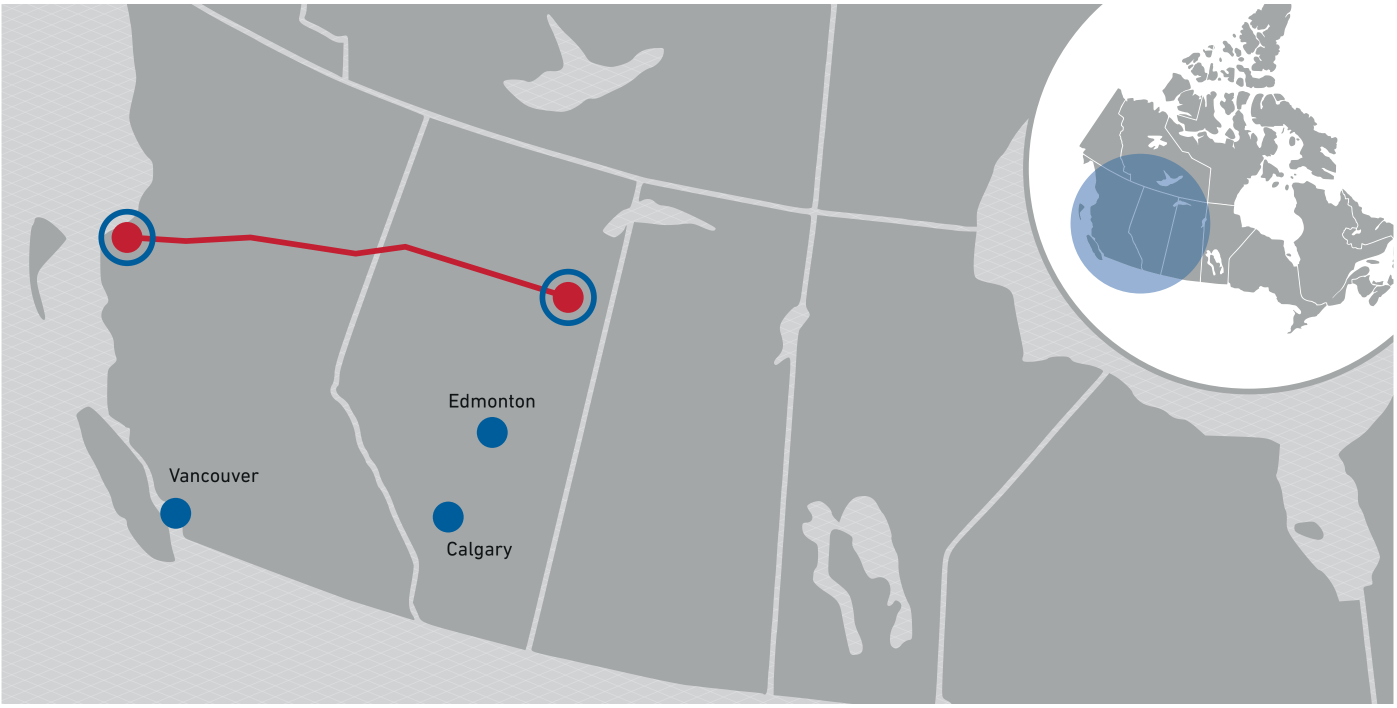
150. Indian Resource Council, Organization, IRC Staff, Mr. Stephen Buffalo.

151. Germain Belzile and Alexandre Moreau, *op. cit.*, footnote 143, pp. 9 and 23.

152. Stephen Buffalo, "We are First Nations that support pipelines, when pipelines support First Nations," *Financial Post*, September 13, 2018.

Figure 4-1

Working survey map, Eagle Spirit energy pipeline



Source: John Paul Tasker, "Pro-pipeline First Nations spar with environmental activists over 'devastating' tanker ban bill," *CBC News*, December 11, 2018.

It is worth noting that after the dismissal of the Northern Gateway pipeline project and the legal quagmire around the twinning of the Trans Mountain project (where, in both cases, the Federal Court of Appeals quashed projects previously approved by the National Energy Board), some of the main opposition to Bill C-48, the Oil Tanker Moratorium, is coming from First Nations-led groups promoting their own pipeline project, Eagle Spirit,[153] at the same time as the IRC is asking the federal government to put Bill C-69 on hold because of the difficult situation in which the oil and gas sector finds itself.[154]

Two examples of such potential corridors deserve short-term attention: the corridor where the above-mentioned Eagle Spirit pipeline would be located, and the corridor where the newly suggested Gazoduq pipeline in Quebec would be located.

Some of the main opposition to Bill C-48, the Oil Tanker Moratorium, is coming from First Nations-led groups promoting their own pipeline project, Eagle Spirit.

The proposed Eagle Spirit pipeline would run between northern Alberta and the northwestern shore of British Columbia. It would follow a much more northerly course than the earlier-proposed Northern Gateway project, as shown in Figure 4-1.[155]

Given the logic of energy corridors described above, it would make sense, at least for the coastal part of the pipeline, to pre-negotiate with all stakeholders the potential laying of a gas pipeline—as well as other installations—along the same corridor.

The second location for the pre-establishment of such a corridor would be the potential Gazoduq gas pipeline

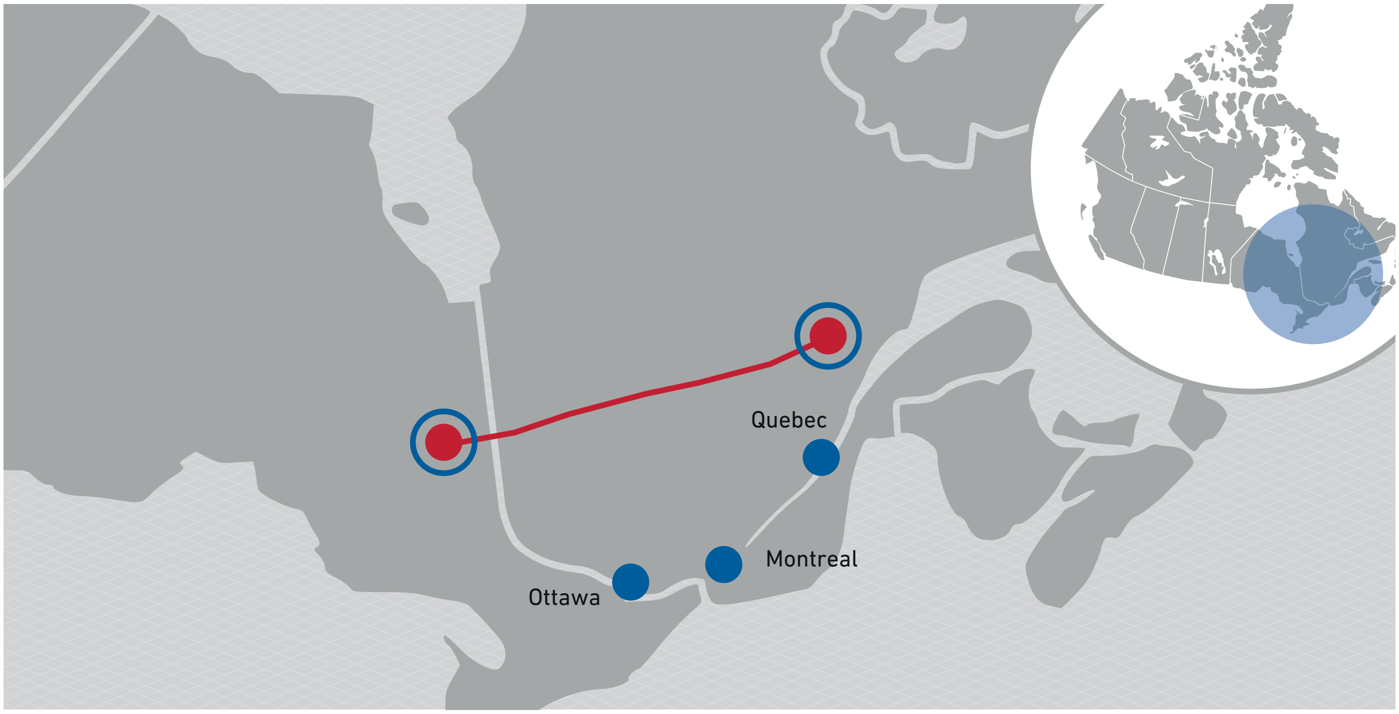
153. Jesse Snyder, "First Nations coalition calls for rejection of Trudeau tanker ban; one group plans to file UN complaint," *National Post*, December 11, 2018; John Paul Tasker, "Pro-pipeline First Nations spar with environmental activists over 'devastating' tanker ban bill," *CBC News*, December 11, 2018.

154. Stephen Buffalo and Ken Coates, "Bill C-69, it's also contentious within Indigenous communities," *Toronto Sun*, December 3, 2018.

155. John Paul Tasker, *op. cit.*, footnote 153.

Figure 4-2

Gazoduq pipeline between Quebec-Ontario border and the Saguenay River



Source: Gazoduq, Documentation, Maps.

between the Quebec-Ontario border and the Saguenay River, shown in Figure 4-2, which provides deep-tide-water access.

The promotors of Gazoduq have already begun consulting with local First Nations.[156] When compared to the previous Energy East project—an oil pipeline—the new Gazoduq project follows a path located hundreds of kilometers further north. Energy East was to cross the Ottawa River near Montreal and hugged the northern shore of the Saint Lawrence River all the way to Quebec City, where it was to cross the Saint Lawrence.[157] This path, within a short distance from much of the population of Quebec, might have been expected to create an uproar, which it did.[158]

Two examples of potential corridors deserve short-term attention: the corridor where the Eagle Spirit pipeline would be located, and the corridor where the Gazoduq pipeline in Quebec would be located.

The Gazoduq path is located away from dense population clusters and roughly follows the watershed divide between southerly and northerly flowing rivers, which means that it would cross few rivers and creeks. While negotiations are taking place with the various stakeholders, it would make sense to keep in mind that this proposed path could eventually also be used for an oil pipeline. The above-mentioned Indian Resource Council could potentially be the entity overseeing this process.

156. Gazoduq, *Projet Gazoduq, Avis de projet* déposé au Ministère de l'Environnement et de la Lutte contre les changements climatiques, November 2018, pp. 16-19.

157. Government of Canada, National Energy Board, Applications & Filings, Major Applications and Projects, Energy East and Eastern Mainline Projects.

158. The Canadian Press, "TransCanada cancels $15.7B Energy East pipeline project," *Calgary Herald*, October 5, 2017.

CHAPTER 5

Other Issues

In addition to the issues raised in the preceding chapters, there are several others which are less important to the health of the industry, but which are significant enough to merit at least a brief mention. These are fugitive methane emissions, the Federal Clean Fuel Standard, and the matter of orphan wells.

Fugitive Methane Emissions

In June 2016, during a meeting in Ottawa, Prime Minister Trudeau, U.S. President Obama, and Mexican President Peña Nieto announced a North America-wide goal to reduce methane emissions from the oil and gas industry by 40% to 45%.[159] The Trump administration later reversed President Obama's decision.[160] However, major oil producers around the world, including ExxonMobil, Royal Dutch Shell, Total, and BP, have announced their commitment to reduce methane emissions as part of their efforts to promote natural gas as a substitute for coal.[161]

Methane is a much more potent greenhouse gas than carbon dioxide. Alberta's Carbon Offset Emission Factors Handbook[162] assesses that it is 25 times more potent than CO_2. Other more recent evaluations estimate that it is over 80 times more potent.[163] Flaring is therefore preferable to venting, since burning methane produces carbon dioxide, and thus reduces GHGs by the same factor.[164]

Methane emissions are not caused only by oil and gas production, but also by numerous other human activities, including farming. In the oil and gas sector, methane emissions are mainly associated with natural gas operations, including drilling, production, and consumption. Alberta and British Columbia—the main gas producing provinces—are committed to reducing methane emissions by 45% by 2025, compared to 2012 levels.[165] However, measuring leaks is not an easy task.

Alberta and British Columbia—the main gas producing provinces—are committed to reducing methane emissions by 45% by 2025.

Reducing fugitive methane emissions is broadly perceived as the right thing to do, and does not generate major complaints from the oil and gas sector.

Federal Clean Fuel Standard

In addition to the carbon tax, in 2017, the federal government introduced another policy aiming to reduce the carbon intensity of fuels by 2030 via incentives to reduce methane emissions. For instance, the blending of hydrocarbon fuels with alternative products such as ethanol and renewable diesel, vegetable oil, natural gas from municipal waste, forestry residues, biomass, etc. It is alleged that the Clean Fuel Standard will assess whole lifecycle gas emissions.[166]

From its inception early in 2017, the proposed Federal Clean Fuel Standard has been identified as duplicating existing provincial and federal emission reduction policies.[167] It is essentially another carbon tax under a different name. Assessing the lifecycle gas emissions of blended products would be complex at the very least, and next to impossible in some cases, since oil and gas, being fungible, lose their identity as they are mixed, loaded in a pipeline, or processed by various facilities.[168]

159. Prime Minister of Canada, Leaders' Statement on a North American Climate, Clean Energy, and Environment Partnership, Ottawa, Ontario, June 29, 2016.

160. Timothy Gardner, "Trump administration eases rule on methane leaks on public land," *Reuters*, September 18, 2018; Andrew Ward and Ed Crooks, "Oil majors move to cut methane emissions," *Financial Times*, November 22, 2017.

161. Andrew Ward and Ed Crooks, *ibid.*; Ed Crooks, "ExxonMobil moves to cut its methane emissions," *Financial Times*, September 25, 2017; Climate and Clean Air Coalition (CCAC), "Reducing methane emissions across the natural gas value chain – Guiding principles," November 22, 2017.

162. Government of Alberta, "Carbon Offset Emission Factors Handbook: Specified Gas Emitters Regulation," March 2015, p. 5.

163. Emily Macintosh, "Methane, the greenhouse gas 86 times worse than CO_2, finally targeted by meps," Meta (from the European Environmental Bureau), December 7, 2017; Jennifer A. Dlouhy, "White House Backed Big Oil Over EPA on Finding Methane Leaks," *Bloomberg*, October 19, 2018; Timothy Gardner, *op. cit.*, footnote 160.

164. Eniscuola (Eni's School of Energy and Environment), Energy, Natural Gas, Environment and territory, Gas flaring and gas venting.

165. BC Oil and Gas Commission, Public Zone, Reducing Methane Emissions; Government of Alberta, Environment, Climate change, Climate Leadership Plan, Reducing methane emissions.

166. Environment and natural resources, Pollution and waste management, Pollution sources and prevention, Managing pollution, Fuel regulations: regulatory text, guidance, reporting; Environment and Climate Change Canada, "Clean Fuel Standard: Regulatory Design Paper," December 2018.

167. Chemistry Industry Association of Canada, "Natural gas costs to double for chemistry industry under the proposed Clean Fuel Standard," Press Release, April 9, 2019; Canada's Oil & Natural Gas Producers, "Re: CAPP Comments on Clean Fuel Standard Discussion Paper," April 25, 2017, pp. 3-4.

168. Canada's Oil & Natural Gas Producers, *ibid.*

Other research groups have negatively assessed the proposed policy. For example, the C.D. Howe Institute published, in July 2018, a report which thoroughly analyzes the proposed Clean Fuel Standard. The report summarized the proposal as too murky, and stressed the need to examine how it will interact with existing provincial regulations and standards.[169]

The draft Clean Fuel Standard methodology uses an incomplete lifecycle assessment, which ignores indirect land-use changes.[170] A complete lifecycle assessment would attempt to calculate the environmental impact of every step, including extraction, refining, transportation to market, and combustion of different fuels. To compare apples with apples—in our case the amount of carbon being produced by different fuels or fuel from different origins—one would have to calculate CO_2 emissions from a fuel produced by a Canadian operation and compare them with the emissions arising from imported fuel. However, how can one reasonably assess the quantity of CO_2 produced by oil and gas wells in OPEC countries? What about their fugitive emissions, flaring, and venting policies? As the C.D. Howe report mentions: "One [problem] is to determine conclusively the total amount of emissions created during the production of the fuel, which cannot be done simply by burning the fuel in a test facility."[171]

The proposed methodology, which ignores indirect land-use changes, would *de facto* affect the relative GHG intensity of biofuels vs. gasoline and diesel, in favour of biofuels.

While exploiting the fuel capabilities of all types of waste (municipal, farm) makes sense, attempting to increase the usage of fuels like ethanol, renewable diesel, and forestry residues is another story. These fuels are not a sustainable option because the ratio between the amount of fuel produced and the amount of fuel necessary for their production, known as the Energy Returned on Energy Invested Ratio (EROEI or EROI) is far too low.[172] The most likely outcome from this misguided policy would be to force fuel suppliers to rely on corn-based ethanol and oil seed-based biofuels. Some research comparing different types of policies has shown that implementing renewable fuel standards led to an increase in food prices and a smaller reduction in global GHG emissions compared to other policy options (such as a carbon tax).[173]

The proposed Federal Clean Fuel Standard has been identified as duplicating existing provincial and federal emission reduction policies. It is essentially another carbon tax under a different name.

The Clean Fuel Standard is clearly a duplicative policy which finds its source in existing fuel standards, both at the federal and provincial levels. It is unclear if the proposed policy would replace the existing Renewable Fuels Regulations (or "RFS" for renewable fuels standard).[174] It is also unknown if provinces would keep in place their own clean fuels regulations, adding another layer of complexity.[175] The Alberta government has opposed to the Clean Fuel Standard, stating that it could undermine efforts the province undertook to reduce carbon emissions and would be a burden for individuals and trade-exposed industries.[176]

It appears that the federal government has not published the economic cost of this proposed policy, and has not presented arguments supporting it.[177]

The Clean Fuel Standard is a perfect case of the left hand not knowing what the right hand is doing. It is an attempt to recycle a flawed existing policy without considering the combined impact with other policies targeting the same problem.

Orphan Wells

There are over 120,000 inactive oil and gas wells in Western Canada, around three quarters of which are in Alberta and the remainder mainly in Saskatchewan, but

169. Benjamin Dachis, "Speed Bump Ahead: Ottawa Should Drive Slowly on Clean Fuel Standards," C.D. Howe Institute, E-Brief, July 19, 2018.

170. Environment and Climate Change Canada, *op. cit.*, footnote 166, p. 3.

171. Benjamin Dachis, *op. cit.*, footnote 169, pp. 4-5.

172. David J. Murphy and Charles A. S. Hall, "Year in review—EROI or energy return on (energy) invested," *Annals of the New York Academy of Sciences*, Vol. 1185, No. 1, pp. 102-118; David J. Murphy *et al.*, "New perspectives on the energy return on (energy) investment (EROI) of corn ethanol," *Environment, Development and Sustainability*, Vol. 13, No. 1, February 2011, pp. 179-202; Gianfranco Pergher, "Biomass Energy-Introduction to a Technology Analysis (Summary)," Smart Energy – Network of Excellence, No. 5403, Interreg IV Program Italy – Austria 2007-2013, p. 9.

173. Xiaoguang Chen *et al.*, "Alternative transportation fuel standards: Welfare effects and climate benefits," *Journal of Environmental Economics and Management*, Vol. 67, No. 3, May 2014, pp. 241-257.

174. W. Scott Thurlow, "A better way to expand the renewable fuel industry," *Policy Options*, October 5, 2017.

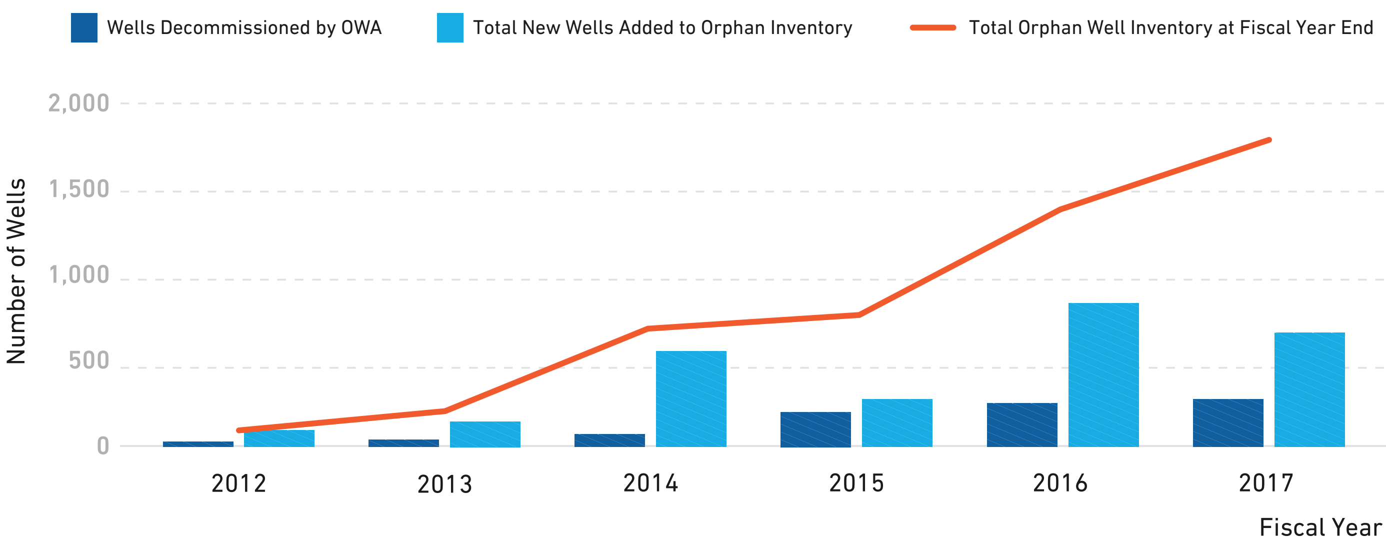
175. Benjamin Dachis, *op. cit.*, footnote 169, p. 9.

176. Kyle Bakx, "Alberta, oilpatch begin public fight with federal government over new fuel regulation," *CBC News*, August 29, 2018.

177. Benjamin Dachis, *op. cit.*, footnote 169, pp. 8-9.

Figure 5-1

Orphan well inventory and wells decommissioned, 2012-2017



Source: Orphan Well Association, 2017 Annual Report, 2017, p. 1.

also in British Columbia.[178] The life of an oil or gas well can be divided into four steps: active, inactive, plugged, and reclaimed. A plugged well means that the borehole has been filled with concrete. Reclaiming a well requires, in addition to this, returning the surface land to its original state. Orphan wells are wells whose owners were unable or unwilling to plug the borehole and/or reclaim the site.

On January 31, 2019, the Supreme Court of Canada ruled that responsibility for wells disowned by Redwater, a bankrupt Alberta oil and gas company, was a duty, and not a debt, which duty could not be erased by going bankrupt. This means that assets owned by a bankrupt company must first be used to reclaim its wells before any distribution to creditors can take place. This is an important milestone, but does not solve the issue.[179]

In a report dated September 2017, the C.D. Howe assesses that in Alberta alone, the number of wells no longer producing but not yet fully remediated was much greater, and closer to 155,000, which is one third of all wells ever drilled in the province.[180]

Research has shown that implementing renewable fuel standards led to an increase in food prices and a smaller reduction in global GHG emissions compared to other policy options.

Management of orphan wells in Alberta is partly covered by the Orphan Well Association (OWA), an independent non-profit organization that operates under the authority of the Alberta Energy Regulator (AER). OWA funding comes primarily from the upstream oil and gas industry through annual levies administered by the AER.[181] The OWA system is a form of pooled insurance.[182]

The AER also employs a second well-liability tool, the Liability Management Rating (LMR). Under LMR, a

178. Jeff Lewis *et al.*, "Hustle in the oil patch: Inside a looming financial and environmental crisis," *The Globe and Mail*, November 23, 2018.

179. Supreme Court of Canada, Cases, Cases in Brief, Case in Brief: Orphan Well Association v. Grant Thornton Ltd.

180. Benjamin Dachis, Blake Shaffer, and Vincent Thivierge, *All's Well that Ends Well: Addressing End-of-Life Liabilities for Oil and Gas Wells*, Commentary No. 492, C.D. Howe Institute, September 2017.

181. Orphan Well Association, About.

182. Benjamin Dachis, Blake Shaffer, and Vincent Thivierge, *op. cit.*, footnote 180, p. 9.

Table 5-1

Changes in Alberta's Orphan Well Inventory for 2017	
DESCRIPTION	**NUMBER OF WELLS**
Reported as of March 31, 2017	1,391
New wells received	666
Completed well abandonments	-259
Other well closures	-20
As of March 31, 2018	**1,778**

Source: Orphan Well Association, 2017 Annual Report, 2017, p. 10.

company is expected to maintain a certain level of financial strength; otherwise, the regulator requires "a security deposit to be made to cover abandonment, remediation, and reclamation costs if a company cannot meet its obligations."[183]

The latest OWA annual report includes some striking graphs. Figure 5-1, from its 2017 report, compares the number of wells decommissioned to the number of new wells added to the orphan wells inventory on a yearly basis. The number of new orphan wells significantly exceeded the number of wells decommissioned every single year since at least 2012. Moreover, Table 5-1 provides detailed information for the year 2017. It shows that during that year, the number of new orphan wells was twice the number of decommissioned and reclaimed wells.

Reclaiming a well requires returning the surface land to its original state. Orphan wells are wells whose owners were unable or unwilling to plug the borehole and/or reclaim the site.

The main issue is that a large number of oil and gas wells (over 140,000) changed hands in all of Western Canada since 2015, and while most sellers were large, financially fit companies, the buyers often were, according to AER, small firms with subpar financial status.[184]

In its report, the C.D. Howe Institute estimates that the full lifecycle cost of decommissioning a well is roughly $100,000, and that the cost associated with orphan wells across Western Canada could reach $8.6 billion.[185] The recent Redwater ruling by the Supreme Court, which essentially gives priority to well decommissioning before paying any money to creditors,[186] should somewhat reduce the problem by forcing operators to use their residential assets to decommission wells. This is a step in the right direction. However, it does not solve the problem, and additional actions must be taken.

183. Alberta Energy Regulator, Regulating Development, Project Closure, Liability Management Programs and Processes, Liability Management Rating and Reporting.

184. Jeff Lewis *et al.*, *op. cit.*, footnote 178.

185. Benjamin Dachis, Blake Shaffer, and Vincent Thivierge, *op. cit.*, footnote 180, p. 15.

186. Supreme Court of Canada, *op. cit.*, footnote 179.

CONCLUSION

Cumulative Impact

As the MEI has stated in previous studies, as the recovery from the fall of the price of oil has been stronger in the US than in Canada—attracting more investment, whereas investment in the Canadian sector has decreased since 2014—Canada is attracting uncertainty, not investment.[187]

As demonstrated above, the biggest challenge facing Canada's crude oil industry is the lack of pipelines. Kinder Morgan originally filed its request for the proposed Trans Mountain expansion late in 2013. The Government of Canada approved it three years later, late in 2016. In order to keep the project alive, the federal government decided to buy the existing pipeline in May 2018 and became the promoter of the proposed expansion. However, later in 2018, the Federal Court of Appeal ruled that some earlier consultations were insufficient and that the regulator should also consider the potential impact of the project on coastal waters. This decision added even more delay, with 84 months now elapsed since the project was first announced in May 2012.[188]

In 2013, the expected benefits of the Trans Mountain expansion for the *whole industry* were estimated to be from US$5 to US$6 per barrel, or US$140 billion for a 20-year period. In subsequent hearings (2015), Kinder Morgan increased this estimate to from US$10 to US$11 per barrel, and approximately US$325 billion for the same period. Based on these two estimates, we can expect the extra revenues to the industry to be between $7 billion and $16 billion per year. These numbers stand. This means that the project, with an estimated cost of over $7 billion, would pay for itself in less than a year.[189]

As we know, in 2018, Alberta imposed a production cap on oil producers in order to minimize the impact caused earlier that year by the lack of pipeline capacity. An alternative to this production cap could be to exempt from the cap additional production for which the producer would commit to rail shipment.

The second largest issue is carbon taxes. As mentioned earlier, this report neither endorses nor opposes the principle of carbon taxes. However, should carbon taxes be enacted, their structure should respect the basic principles of economics.

The basic principle by which carbon taxes are levied in Canada—and in most countries—is wrong. Canada, and Alberta, are taxing carbon at the production level, which penalizes extractive industries and prevents them from competing on an equal footing with their foreign competitors. To make such a system fairer, if governments are to tax "Energy-Intensive, Trade-Exposed" (EITE) firms, the said governments would need to insulate them from untaxed imported goods. This would mean taxing imported carbon-heavy goods and exempting exported goods from the tax, i.e., using the same logic which underlies the Goods and Services Tax (GST). Under this logic, Alberta could exempt exported oil and gas to the U.S.—or elsewhere overseas—from the carbon tax. However, as mentioned in Chapter 2, a unilateral border-adjustment system could create a backlash, and might even lead to a trade war with our trading partners. Ideally, such a system would have to be implemented internationally in order to work without running the risk of damaging international trade.

The biggest challenge facing Canada's crude oil industry is the lack of pipelines. Kinder Morgan originally filed its request for the proposed Trans Mountain expansion late in 2013.

Another issue with Alberta's existing carbon tax for large emitters is the level above which oil and gas producers must pay for their emissions. If the emissions benchmark, i.e., the neutral point, was the mid-point of the distribution—instead of the top-quartile—the impact of the tax would be neutral, with as many winners as losers. That said, the firms whose carbon emissions are below the benchmark do not have to receive carbons credits. However, firms whose emissions exceed the benchmark would still have an incentive to reduce their footprint.

Government may also widen the available tools for acquiring required carbon credits. Alberta-based heavy emitters presently are paying a higher price than emitters in other provinces, such as Quebec. For example, instead of setting a fixed price, government could legislate

187. Germain Belzile, *Canada's Oil and Gas Sector at Risk? How Excessive Taxes and Regulations Undermine Our Competitiveness*, Research Paper, MEI, October 2017, pp. 11-21; Alexandre Moreau and Germain Belzile, *op. cit.*, footnote 14.

188. Alexandre Moreau and Germain Belzile, *ibid.*

189. Trans Mountain, *Trans Mountain Pipeline ULC Trans Mountain Expansion Project NEB Hearing Order OH-001-2014 Responses to Information Request from National Energy Board*, February 3, 2015, p. 11.

a target price, but in such a way that it should not exceed the lowest of:

- The price of carbon credits under the Quebec-California market; or
- The price of carbon credits under an approved UN Framework Convention on Climate Change (UNFCCC) carbon credit trading mechanism.

The third most important issue affecting Alberta's oil and gas industry is the regulatory issue. Late in 2017, the Alberta Energy Regulator introduced the new "Integrated Decision Approach" (IDA) for oil and gas projects, which makes use of OneStop, a digital platform designed to ease the processing of applications.[190] The new approach covers all activities over the life of an oil and gas project from construction and operation through to abandonment and reclamation. It is still in its infancy. It has been road-tested on a few projects and is being gradually implemented, but it will not be fully implemented before 2021.[191]

As was mentioned before, Alberta ought to benchmark its regulations to the best practices seen in other jurisdictions. This is an area which is fully under the province's control, and again, it is an existential question for Alberta's oil and gas industry.

In addition to these three prominent issues, another one, mainly under the federal government's control, has arisen over the past few years: the proposed Federal Clean Fuel Standard. Simply put, the Clean Fuel Standard is a misguided and duplicative policy which should be scrapped. The mandatory introduction of ethanol and the like into the fuel stream was initiated at a time when North Americans believed they were about to run out of oil. The policy was later recycled as an attempt to reduce carbon emissions. It is simply not sustainable, and clearly duplicates carbon taxes. The federal government should kill it.

Finally, there are two remaining points: fugitive methane emissions and orphan wells. The Canadian oil and gas industry, like many international oil and gas producers, has begun to address methane emissions. The industry is fully aware that, for gas to be promoted as an environmentally friendlier fuel than coal, methane leaks ought to be minimized. The industry should also take appropriate action to solve the orphan wells issue. Large firms must stop the sale or transfer of old, non-reclaimed wells to less financially solid companies, and the whole industry must increase the plugging and reclamation rate of wells—failing which, the provincial regulators will sooner or later impose more stringent conditions.

The cumulative impact of the lack of market access, of carbon taxes at the production level without border protection, of sprawling regulations, and of some other issues, has already resulted in a sharp reduction of investment in Alberta's oil and gas sector. Investment has fallen by half, from $81 billion in 2014 to $40 billion in 2018.[192] The oil sands, requiring longer lead-times, have been more heavily impacted by this uncertainty: The sector experienced an even sharper drop in investment, from $34 billion to $11 billion over the same period.[193]

Global oil demand is expected to continue growing. The question facing Canadians is thus whether to continue, responsibly but proactively, to supply some of that demand, or leave our resources in the ground.

As noted at the outset of this paper, global oil demand is expected to continue growing through to at least 2040, according to the IEA's most likely New Policies Scenario. The question facing Canadians is thus whether to continue, responsibly but proactively, to supply some of that demand, or leave our resources in the ground and let others supply it. As the oil and gas sector is a vital part of our economy, we should strive to eliminate the unnecessary hurdles and misguided policies that reduce the well-being of Canadians while providing little to no benefit for the natural environment.

190. Alberta Energy Regulator, Regulating Development, Project Application, Integrated Decision Approach; Esri Canada, "Alberta Energy Regulator Lauded for Streamlining Regulatory Process with GIS," News Release, September 19, 2018.

191. James Wood, "One-stop software tool for oilpatch to cut approval time, costs: NDP," *Calgary Herald*, August 22, 2018; "Alberta's streamlined regulatory regime saves energy industry $140M, minister says," *CBC News*, August 21, 2018.

192. National Energy Board, "Market Snapshot: Investment in Canada's oil and gas sector declined from 2014 high," August 1st, 2018.

193. *Ibid.*

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