RECENT LEGISLATIVE AND REGULATORY DEVELOPMENTS OF INTEREST TO ENERGY PRACTITIONERS

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This article discusses recent developments in the regulatory and legislative spheres that are of interest to energy practitioners. The authors reviewed regulatory initiatives, decisions, related case law, and legislation from provincial, territorial, and federal authorities. Topics of note include: recent climate change policy updates, renewable energy policy initiatives, oil and gas regulatory developments, pipeline project updates, and Aboriginal case law developments. The period covered is May 2016 to June 2017, inclusive.

TABLE OF CONTENTS

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I. INTRODUCTION

As the Canadian energy policy and regulatory landscape continues to evolve, the concepts of "sustainable resource development" and "decarbonization" are becoming increasingly prominent as two key drivers of Canadian energy policy. In 2016, federal and provincial governments sought to establish a road map for a path towards a sustainable, less carbon-intensive economy. Guided by the *Vancouver Declaration on Clean Growth and Climate Change*,[1] federal, provincial, and territorial governments focused their policy efforts in 2016 on four priority areas — clean technology, carbon pricing, climate change mitigation, and adaptation measures.[2] This culminated in the "Pan-Canadian Framework on Clean Growth and Climate Change,"[3] which was released in December 2016. The principles set out in the "Pan-Canadian Framework" are driving energy policies at the federal, provincial, and territorial levels. From the implementation of carbon pricing and the development of a clean fuel standard, to investments in clean technology and green infrastructure, efforts are now focused on implementing the "Pan-Canadian Framework." At the same time, the economic imperative for creating jobs, maintaining competitiveness, and boosting access to global commodity markets is driving federal and provincial approvals of energy projects, which in turn need to be supported by robust and transparent regulatory review processes. As the public clamours for greater accountability in the development of resource projects, companies are increasingly aware of the need for social licence in order to maintain productive relations with a range of stakeholders. This public need for accountability is reflected in legal challenges by landowners, Aboriginal groups, and industry stakeholders to a host of regulatory processes and to resource projects themselves. With all of these issues at play, Canada's energy sector continues to be a dynamic environment for governments, industry, and stakeholders to operate in.

This article is intended to highlight key policy, regulatory, and case law developments of interest to energy practitioners, and covers developments that have taken place since the last review. This article is organized into eight topics under relevant headings where the respective legislative and policy developments, as well as judicial and administrative decisions, are discussed with reference to the topical heading.

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1 See online: Inuit Tapiriit Kanatami <www.itk.ca/wp-content/uploads/2016/04/Vancouver_Declaration_clean_Growth_Climate_Change.pdf>.

2 Office of the Prime Minister, "Communiqué of Canada's First Ministers" (Ottawa: PMO, 3 March 2016), online: <pm.gc.ca/eng/news/2016/03/03/communique-canadas-first-ministers>.

3 Government of Canada, "Pan-Canadian Framework on Clean Growth and Climate Change: Canada's Plan to Address Climate Change and Grow the Economy" (2016), online: <https://www.canada.ca/content/dam/themes/environment/documents/weather1/20170125-en.pdf> ["Pan-Canadian Framework"].

II. CLIMATE CHANGE

A. FEDERAL

1. "PAN-CANADIAN FRAMEWORK ON CLEAN GROWTH AND CLIMATE CHANGE"

The "Pan-Canadian Framework" was released at the First Ministers meeting on 9 December 2016.[4] It followed the 3 October 2016 announcement by the federal government that it will establish a minimum price on carbon starting at $10 per tonne of carbon dioxide equivalent (CO_2e) in 2018, which will increase by $10 per year until it reaches $50 per tonne of CO_2e by 2022.[5] Under the federal carbon pricing plan, each province and territory will be required to implement carbon pricing in its jurisdiction by 2018, whether in the form of a carbon tax or a cap-and-trade system. If the carbon price in a jurisdiction does not meet the federal minimum price, the federal government will step in and impose a carbon price that makes up the difference and return the revenue to the province or territory.[6] Ontario, Quebec, Alberta, and British Columbia currently have carbon pricing regimes in place. The federal government has also said that provincial and territorial goals for reducing emissions must be at least as stringent as the federal reduction target of 30 percent from 2005 levels by 2030.[7] The "Pan-Canadian Framework" outlines critical actions for growing the economy while reducing greenhouse gas (GHG) emissions, including:

- developing new building codes to ensure more energy efficient buildings;
- deploying more electric charging stations to support zero emission vehicles;
- expanding clean electricity systems, promoting inter-ties, and using smart-grid technologies to phase out the reliance on coal, make more efficient use of existing power supplies, and ensuring a greater use of renewable energy;
- reducing methane emissions from the oil and gas sector;

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4 Saskatchewan has decided not to adopt the "Pan-Canadian Framework": see Office of the Prime Minister, "Communiqué of Canada's First Ministers" (Ottawa: PMO, 9 December 2016) [December Communiqué], online: <pm.gc.ca/eng/news/2016/12/09/communique-canadas-first-ministers>. While Manitoba has not signed on to the "Pan-Canadian Framework," it is in the process of developing a "Made-in-Manitoba Climate Action Plan" that will fulfil federal obligations. See online: Government of Manitoba <www.gov.mb.ca/sd/climate>.

5 Kathleen Harris, "Justin Trudeau Gives Provinces Until 2018 to Adopt Carbon Price Plan," *CBC News* (3 October 2016), online: <www.cbc.ca/news/politics/canada-trudeau-climate-change-1.3788825>.

6 *Ibid*.

7 In May 2015, the federal government submitted this target (also referred to as its intended nationally determined contribution) to the *United Nations Framework Convention on Climate Change* Secretariat: see *Canada's INDC Submission to the UNFCCC*, online: <www4.unfccc.int/submissions/INDC/Published%20Documents/Canada/1/INDC%20-%20Canada%20-%20English.pdf>. Meeting Canada's 2030 target will require a reduction from the 2005 level of 747 megatonnes (Mt) to 523 Mt of CO_2e; in the absence of additional actions, Environment and Climate Change Canada projects that Canada's emissions will be 742 Mt of CO_2e in 2030 (see "Canada's 2016 Greenhouse Gas Emissions Reference Case" (Ottawa: ECCC, 2017), online: <https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=1F24D9EE-1>.

- protecting and enhancing carbon stored in forested lands, wetlands and agricultural lands; and

- achieving significant reductions in emissions from government operations.[8]

Provincial and territorial officials have been tasked with implementing the "Pan-Canadian Framework" and reporting back to the First Ministers on their progress by December 2017 (and annually thereafter). Federal, provincial, and territorial governments will undertake a review of carbon pricing (including expert assessment of the stringency and effectiveness of carbon pricing systems across Canada) by early 2022 to provide direction on the path forward.[9] An interim report will be completed in 2020, which will be reviewed and assessed by the First Ministers. As an early deliverable, the review will assess approaches and best practices to address the competitiveness of emissions-intensive and trade-exposed sectors.[10]

2. FEDERAL GOVERNMENT LAUNCHES PROCESS TO DEVELOP A CLEAN FUEL STANDARD

Environment and Climate Change Canada (ECCC) has launched a process to develop a clean fuel standard (CFS) to help Canada meet its GHG emissions reduction target of 30 percent below 2005 levels by 2030. ECCC released a discussion paper on 24 February 2016 to facilitate public consultation on the proposed new CFS.[11] The CFS will be developed under the authority of the *Canadian Environmental Protection Act, 1999*[12] and will be based on a performance-based approach that will incentivize the use of a broad range of lower carbon fuels and alternative energy sources including electricity, natural gas, hydrogen, and renewable fuels. ECCC has indicated that the CFS will go beyond transportation to include fuels used in industry, homes, and buildings. Further, the CFS will build on the existing foundation established under the federal *Renewable Fuels Regulations*.[13] The public comment period for the discussion paper closed on 25 April 2017, and ECCC is now working on a draft regulatory framework for the CFS. ECCC is expected to release draft regulations in mid-2018, with final regulations to be published in 2019.

B. BRITISH COLUMBIA

1. CLIMATE LEADERSHIP PLAN

In August 2016, the British Columbia government released its *Climate Leadership Plan*,[14] which updates the province's 2008 "Climate Action Plan."[15] The 2016 Plan contains 21 new

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8 See December Communiqué, *supra* note 4.
9 See *ibid*.
10 *Ibid*.
11 Environment and Climate Change Canada, "Clean Fuel Standard: Discussion Paper" (Ottawa: ECCC, 2017), online: <https://www.ec.gc.ca/lcpe-cepa/D7C913BB-13D0-42AF-9BC7-FBC1580C2F4B/CFS_discussion_paper_2017-02-24-eng.pdf>.
12 SC 1999, c 33.
13 SOR/2010-189.
14 British Columbia, *Climate Leadership Plan* (Victoria: Government of British Columbia, 2016), online: <https://climate.gov.bc.ca/app/uploads/sites/13/2016/10/4030_CLP_Booklet_web.pdf> [*Climate Leadership Plan*].
15 British Columbia, *Climate Action Plan* (Victoria: Government of British Columbia, 2008), online: <www.gov.bc.ca/premier/attachments/climate_action_plan.pdf>.

actions to reduce emissions across the following sectors: (1) natural gas, (2) transportation, (3) forestry and agriculture, (4) communities and built environment, and (5) public sector leadership. It is anticipated that British Columbia will fall short of achieving its 2020 emission reduction target of 33 percent below 2007 levels by 2020.[16] As a result, the *Climate Leadership Plan* bypasses British Columbia's 2020 target and instead charts a path for British Columbia to reach its 2050 target of 80 percent below 2007 levels.[17] Of interest to the energy sector is the British Columbia government's planned action for the natural gas industry, which includes initiatives in three key areas: (1) launching a strategy to reduce upstream methane emissions by 45 percent by 2025 from legacy extraction and processing infrastructure built before January 2015; (2) developing regulations to enable carbon capture and storage of emissions from industrial facilities; and (3) electrification of upstream natural gas production activities. These actions are expected to reduce annual emissions by up to 5 million tonnes by 2050.[18] While the fate of the *Climate Leadership Plan* is uncertain following the results of the British Columbia election in May 2017, it is expected that the incoming minority NDP-Green government will take more aggressive action on climate change. In the *2017 Confidence and Supply Agreement Between the BC Green Caucus and the BC New Democrat Caucus*,[19] both parties have agreed to implement an increase of the carbon tax by $5.00 per tonne per year,[20] beginning on 1 April 2018,[21] and to expand the tax to fugitive emissions and to slash-pile burning. Further, both parties have committed to implementing a climate action strategy to meet the province's emission reduction targets.[22]

C. ALBERTA

1. *CLIMATE LEADERSHIP IMPLEMENTATION ACT*

The Alberta legislature passed the *Climate Leadership Act* on 23 June 2016.[23] The *CLA*, which came into force on 1 January 2017, furthers the implementation of the Alberta Climate Leadership Plan. Details of Alberta's carbon pricing model were provided in its April 2016 budget, which earmarked funds for building and modernizing infrastructure (approximately

16 According to British Columbia, Ministry of Environment, *Greenhouse Gas Inventory Report 2007* (Victoria: Ministry of Environment, 2009) at 7, online: <www2.gov.bc.ca/assets/gov/environment/climate-change/data/provincial-inventory/2007/pir-2007-full-report.pdf>), total GHG emissions in British Columbia in 2007 were 67.3 Mt CO_2e (*ibid* at 13). ECCC projects that British Columbia's GHG emissions will be 69 Mt CO_2e in 2020 (see Environment and Climate Change Canada, "Canada's Emissions Trends 2014," online: <https://www.ec.gc.ca/GES-GHG/default.asp?lang=En&n=E0533893-1&offset=5&toc=show#toc56>).

17 *Climate Leadership Plan*, *supra* note 14 at 12.

18 *Ibid* at 5. Following the legacy phase, the *Climate Leadership Plan* says that methane emissions will be followed by two additional phases: transition phase and future phase. The transition phase will offer incentives to drive methane emissions reductions for all applications built between 2015 and 2018, and to help tackle legacy infrastructure retrofitting. Incentives will include an offset protocol and a Clean Infrastructure Royalty Credit Program to help stimulate investments in new technology to convert current infrastructure to less carbon-intensive machinery. The future phase will establish standards to guide the development of projects after the transition phase. According to the *Climate Leadership Plan*, oil and gas production accounts for approximately 11 million tonnes of annual GHG emissions in British Columbia, 2.2 million tonnes of which are attributable to fugitive and vented methane emissions released during the production process (*ibid* at 15–17).

19 See online: British Columbia New Democratic Party <https://www.bcndp.ca/latest/its-time-new-kind-government-british-columbia>.

20 *Ibid* at 4.

21 Under the previous British Columbia Liberal Government, Premier Christy Clark had indicated that British Columbia would not increase its carbon price until other jurisdictions caught up.

22 See *supra* note 19 at 4–6.

23 SA 2016, c C-16.9 [*CLA*].

$8.5 billion) and climate change initiatives (approximately $634 million).[24] The *CLA* also provides the legislative authority for the Alberta government to impose a carbon levy in the province. As of 1 January 2017, a $20 per tonne carbon levy is being applied to fuels that emit GHG when combusted.[25] The carbon levy will increase to $30 per tonne in 2018. Revenues from the carbon levy will be used for initiatives to reduce GHG emissions and to fund carbon rebates, as well as for investments in clean technology and green infrastructure. The carbon levy will also be used for an "adjustment fund" to help individuals, families, and small businesses adjust as the new carbon pricing regime takes effect.[26]

2. *OIL SANDS EMISSIONS LIMIT ACT*

The reduction of emissions from oil sands operations (which represent approximately one quarter of Alberta's GHG emissions) is one of the key GHG emission reduction strategies under the Alberta Climate Leadership Plan. On 1 November 2016, the *Oil Sands Emissions Limit Act* was introduced, which legislates an annual cap of 100 Mt on emissions from oil sands production.[27] The legislation contemplates certain exceptions in respect of co-generation emissions, upgrading emissions, and potential discretionary exemptions by regulation.[28] It came into force on 14 December 2016. The provincial government has not yet released details on how the emissions cap will be implemented, including monitoring and enforcement. There is also uncertainty surrounding the fate of oil sands projects that have already been approved, particularly where the price of oil increases and the economic conditions for such projects improve. However, the provincial government has established an 18-member Oil Sands Advisory Group, which has been mandated to:

- consider how to implement the cap on oil sands emissions;
- develop durable, effective structures and processes to address local and regional environmental issues (including air, land, water, biodiversity, and cumulative effects); and
- provide advice to the government on investing carbon price revenue in innovations to reduce future emissions intensity.[29]

The report of the Oil Sands Advisory Group was released on 16 June 2017, and sets out recommendations on early actions designed to encourage additional emissions reductions, as well as additional actions in the event that emissions begin to approach the limit.[30] These actions are intended to work in concert with the output-based allocation system for carbon

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24 Alberta, *Fiscal Plan: Tax Plan* (Edmonton: Government of Alberta, 2016) at 93–98, online: <finance.alberta.ca/publications/budget/budget2016/fiscal-plan-tax-plan.pdf> [*Fiscal Plan*].

25 A complete list of carbon levy rates, by type of fuel, is set out in Alberta's *Fiscal Plan*, *ibid* at 106.

26 *Ibid* at 97–98.

27 SA 2016, c O-7.5, s 2(1) [*OSELA*]. According to the Alberta government, the oil sands sector currently emits approximately 70 Mt annually: see Alberta, "Capping Oil Sands Emissions," online: <https://www.alberta.ca/climate-oilsands-emissions.aspx>.

28 *OSELA*, *ibid*, s 2(2).

29 For more information on the Oil Sands Advisory Group (including terms of reference, mandate letters, and a list of members), see Alberta, Oilsands Advisory Group, online: <https://www.alberta.ca/oilsands-advisory-group.aspx>.

30 See online: Government of Alberta <https://open.alberta.ca/publications/9781460134740>.

pricing and to encourage GHG efficiency so that aggregate emissions remain under the limit without limiting production.[31]

3. METHANE EMISSIONS CHALLENGE

Another key emission reduction strategy under the Alberta Climate Leadership Plan is the reduction of methane emissions from the oil and gas sector. Alberta is aiming to cut methane emissions by 45 percent from 2014 levels by 2025.[32] In October 2016, Emissions Reduction Alberta (formerly Climate Change and Emissions Management Corporation) launched its $40 Million Methane Challenge program, the objective of which is to develop technologies that address methane detection, methane quantification, and reduction of methane emissions in Alberta.[33]

D. ONTARIO

1. *CLIMATE CHANGE MITIGATION AND LOW-CARBON ECONOMY ACT* AND REGULATIONS

On 18 May 2016, Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016*[34] and *The Cap and Trade Program* regulation[35] under the *Act* (the regulation came into force in May 2016 along with the incorporated *Methodology for the Distribution of Ontario Emission Allowances Free of Charge*).[36] Together, the *Act* and regulation provide the regulatory framework for Ontario's cap-and-trade program, which is the key policy initiative designed for reducing Ontario's GHG emissions. In addition, the new *Quantification, Reporting and Verification of Greenhouse Gas Emission*[37] regulation and incorporated Guideline both came into force on 1 January 2017 and apply to activities carried out by persons on and after that date. The predecessor legislation, the *Greenhouse Gas Emissions Reporting* regulation,[38] will be revoked after all reporting under it is complete.

2. CLIMATE CHANGE ACTION PLAN

The Ontario Government released its 5-year *Climate Change Action Plan* in June 2016, which sets out the province's specific commitments to meet its near-term 2020 emissions reduction targets.[39] The actions identified in the plan will be supported by proceeds from the cap-and-trade program and include a broad range of initiatives:

- establishing a green bank to enable households and businesses to access and finance energy-efficient technologies to reduce GHG emissions from buildings;

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31 *Ibid*.
32 These details, and a list of shortlisted projects (as of March 2017) is available on the Emissions Reduction Alberta website, online: <www.eralberta.ca/40-million-era-methane-challenge>.
33 *Ibid*.
34 SO 2016, c 7.
35 O Reg 144/16.
36 See online: Ontario Ministry of the Environment and Climate Change <www.downloads.ene.gov.on.ca/envision/env_reg/er/documents/2016/012-6837_Final%20Methodology.pdf>.
37 O Reg 143/16.
38 O Reg 452/09.
39 Government of Ontario, *Ontario's Five Year Climate Change Action Plan: 2016–2020* (Ontario: Queen's Printer, 2016), online: <www.applications.ene.gov.on.ca/ccap/products/CCAP_ENGLISH.pdf>.

- enhancing opportunities for homeowners and businesses to install or retrofit clean-energy systems such as solar, battery storage, and advanced insulation and heat pumps, while helping to protect and support low-income households and vulnerable communities from the cost impacts of carbon pricing; and

- partnering with First Nations and Metis communities to build capacity to address climate change (with actions guided by Traditional Ecological Knowledge) and participate in related economic opportunities.

Other initiatives include fuel switching to low-carbon fuel, low carbon fuel standards, and electric vehicle incentives.[40]

E. QUEBEC

1. *ENERGY POLICY 2030*

Climate change remains a top priority for the Quebec government. While it did not introduce any new climate change policies in late 2016 or early 2017, in April 2016 it unveiled its energy plans for 2016 to 2030. In its new energy policy, Quebec states its goal of becoming a North American leader in renewable energy and energy efficiency by 2030.[41] The *2030 Energy Policy* succeeds the previous 2006–2015 policy, and was developed following two public consultation periods that took place in 2013 and 2015.[42] While the 2030 Energy Policy does not announce any concrete actions for the procurement of additional renewable energy, it confirms the Quebec government's interest in wind energy, with the caveat that the continued development of wind energy is desirable only to the extent that the impact on consumers is limited and that the additional supply of energy is required in order to meet any fluctuations in Quebec's annual electricity needs. Opportunities for exporting electricity generated from existing wind farms will also be considered.[43]

In other sectors, small hydroelectric projects have been identified as sources of economic development for local and Aboriginal communities.[44] Also, the Quebec government will continue to support bioenergy generation, including biomass cogeneration plants operated by entities in the pulp and paper sector.[45] Natural gas is acknowledged as an important source of transition energy for the province and will play a key role in supporting the future economic development of Quebec, particularly in the north. To that end, the Quebec government will look to expand the current natural gas network, develop a supply network for liquefied natural gas, and increase the production of renewable natural gas.[46] The 2030 Energy Policy also contemplates an overhaul of the current regulatory framework for the

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40 *Ibid* at 8.
41 *The 2030 Energy Policy: Energy in Québec — A Source of Growth* (Quebec: Government of Quebec, 2016) at 11, online: <mern.gouv.qc.ca/english/energy/strategy/pdf/The-2030-Energy-Policy.pdf> [*2030 Energy Policy*].
42 *Ibid*.
43 *Ibid* at 48–51.
44 *Ibid* at 51.
45 *Ibid* at 53.
46 *Ibid* at 54.

development and production of hydrocarbons in Quebec (discussed in further detail below). In addition, *An Act to implement the 2030 Energy Policy and to amend various legislative provisions* was introduced in June 2016 and, following a series of contentious debates, was passed on 10 December 2016.[47]

F. NEW BRUNSWICK

1. TRANSITIONING TO A LOW-CARBON ECONOMY

In December 2016, New Brunswick released a new action plan to address climate change. Entitled *Transitioning to a Low-Carbon Economy: New Brunswick's Climate Change Action Plan*,[48] the plan sets out more than 100 action items to combat climate change including energy efficiency programs, phase-out of coal as a source of electricity, plans to make government carbon neutral by 2030, and establishing a made-in-New Brunswick price on carbon that will meet federal requirements.[49] The New Brunswick government has indicated that proceeds from the province's carbon pricing regime will be directed to a dedicated climate change fund.[50]

G. NOVA SCOTIA

1. CAP AND TRADE PROGRAM DESIGN OPTIONS DISCUSSION PAPER

In order to facilitate the development of the province's cap-and-trade program, Nova Scotia Environment has released a discussion paper entitled "Nova Scotia Cap and Trade Program Design Options."[51] The purpose of the paper is to obtain feedback from stakeholders on the key design elements of the cap-and-trade program. Since 44 percent of Nova Scotia's GHG emissions come from electricity generation, the province's emission reduction strategy has focused primarily on the electricity sector.[52] To support the transition away from coal, Nova Scotia placed hard caps on GHG from the electricity sector in 2009, when the province imposed a GHG reduction requirement of 25 percent by 2020.[53] Following the province's endorsement of the "Pan-Canadian Framework" in December 2016, the Nova Scotia government has chosen to implement a cap-and-trade program which will cover approximately 90 percent of Nova Scotia's GHG emissions.[54] Nova Scotia is proposing that there be no transfers of emissions in or out of the province. As a result, Nova Scotia does not plan to link with a cap-and-trade program in any other jurisdiction at this time.[55] The public comment period ended on 31 March 2017.

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47 CQLR c 35.
48 See online: Government of New Brunswick <www2.gnb.ca/content/dam/gnb/Departments/env/pdf/Climate-Climatiques/TransitioningToALowCarbonEconomy.pdf>.
49 *Ibid*.
50 *Ibid* at 11.
51 See online: Government of Nova Scotia <https://climatechange.novascotia.ca/sites/default/files/Cap-and-Trade-Document.pdf>.
52 *Ibid* at 2.
53 *Ibid* at 3.
54 *Ibid* at 1.
55 *Ibid* at 5.

H. PRINCE EDWARD ISLAND

1. RECOMMENDATIONS FOR CLIMATE CHANGE MITIGATION STRATEGY

Prince Edward Island is taking a two-pronged approach to addressing climate change, which will provide for both mitigation and adaptation strategies. In 2016, Prince Edward Island launched a process to develop a Provincial Climate Change Mitigation Strategy. For this purpose a discussion document was released in July 2016, followed by the release of a draft recommendations report in October 2016.[56] The recommendations include the development of fuel switching programs by the provincial government or a new energy efficiency utility for residents and businesses, a reduction in non-electric energy use in buildings by 2 percent by 2020, development of incentives for electric vehicles, and the introduction of regular emissions testing for all vehicles fueled by diesel and gasoline.[57] On carbon pricing, the recommendations report does not specify the type of carbon pricing mechanism that Prince Edward Island will implement, but it does note that a vast majority of respondents in the consultation process indicated their support for a carbon pricing model that was revenue neutral.[58] The draft recommendations report is a work in progress and will be further refined. Separate but complementary mitigation and adaptation strategies will be developed in 2017. In particular, a mitigation strategy is being developed first, in parallel with a new energy strategy.

2. DRAFT ENERGY STRATEGY

As noted above, Prince Edward Island is in the process of developing a new energy strategy in concert with its climate change mitigation strategy. The province is focused on implementing sustainable energy policies that support energy efficiency and conservation, renewable and alternative energy, and economic development. The *2016 Provincial Energy Strategy: Second Draft* was released in June 2016 and includes specific action items to be pursued over the next five to ten years.[59] In particular, the draft strategy sets out recommended action items in the following areas: (1) energy efficiency and conservation, (2) electricity generation and management, (3) energy storage, (4) biomass, (5) transportation, and (6) cross-sectoral initiatives.[60] Once the strategy is finalized, an implementation plan will be released.

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56 Government of Prince Edward Island, "Prince Edward Island Climate Change Mitigation Strategy Discussion Document" (2016), online: <https://www.princeedwardisland.ca/sites/default/files/publications/climate_change_mitigation_strategy_discussion_document.pdf>; Government of Prince Edward Island, *Recommendations for the Development of a 2016 Climate Change Mitigation Strategy* (2016), online: <https://www.princeedwardisland.ca/sites/default/files/publications/dunsky_-_pei_climate_change_mitigation_draft_recommendations2016.10.21.pdf> [*PEI Recommendations*].

57 *PEI Recommendations*, *ibid.*

58 *Ibid* at 3.

59 Government of Prince Edward Island, *Provincial Energy Strategy: 2016/17*, online: <www.peiec.ca/the-strategy.html>.

60 *Ibid.*

I. NEWFOUNDLAND AND LABRADOR

1. *Management of Greenhouse Gas Act*

The *Management of Greenhouse Gas Act*[61] was passed in June 2016 to establish a legislative framework for reducing greenhouse gas emissions by industrial emitters in the province (defined as those industrial facilities emitting 15,000 tonnes of CO_2e per year).[62] The legislation provides for two years of emissions monitoring to help establish reduction targets that will apply to large industrial facilities that emit 25,000 tonnes of CO_2e per year. In addition, the *Act* requires facilities meeting the 15,000 tonne threshold to submit annual GHG reports and establishes a fund to support emissions reduction technology,[63] which will be 100 percent industry-funded. The intent of the fund is to provide companies with flexibility in achieving emissions reductions at lower cost, while supporting projects that will help the province meet its GHG target. To support this framework, the provincial government has contracted a third party to help develop Newfoundland and Labrador's first carbon offset protocols which will focus on energy efficiency, fuel switching, and renewable energy projects. Also, it was announced in February 2017 that the Office of Climate Change had been placed within the Executive Council following the adoption of the "Pan-Canadian Framework."[64] This move was undertaken to recognize that climate change impacts programs and services across all departments and agencies.[65]

III. ENVIRONMENTAL

A. FEDERAL

1. REVIEW OF CANADIAN ENVIRONMENTAL ASSESSMENT AND REGULATORY PROCESSES

In 2012, omnibus budget legislation[66] introduced by the previous federal government included changes to various federal environmental assessment (EA) review and regulatory processes in respect of projects, including changes to processes under the: (1) *Canadian Environmental Assessment Act, 2012*;[67] (2) *Fisheries Act*;[68] (3) *Navigation Protection Act*;[69] and (4) National Energy Board (NEB) (discussed in further detail below). Following the October 2015 election, the federal Liberals promised to review the changes made in the omnibus legislation in 2012. To that end, the Minister of Environment and Climate Change established an Expert Panel (the Panel) to review processes under the *CEAA, 2012* with a view to making recommendations for the development of "new, fair processes that are robust, incorporate scientific evidence, protect our environment, respect the rights of

61 SNL 2016, c M-1.001.
62 *Ibid*, s 4(1).
63 *Ibid*, ss 6, 10.
64 Executive Council of Newfoundland and Labrador, News Release, "Achieving a More Efficient Public Sector" (22 February 2017), online: <www.releases.gov.nl.ca/releases/2017/exec/0222n03.aspx>.
65 *Ibid*.
66 Bill C-38, *An Act to implement certain provisions of the budget tabled in Parliament on March 29, 2012 and other measures*, 1st Sess, 41st Parl, 2012 (assented to 29 June 2012).
67 SC 2012, c 19, s 52 [*CEAA, 2012*].
68 RSC 1985, c F-14.
69 RSC 1985, c N-22 [*NPA*].

Indigenous peoples, and support economic growth."[70] Public consultations took place between September and December 2016, and recommendations from the Panel were released on 5 April 2017.[71] The Panel's report (the Report) contains numerous recommendations which, if implemented, would result in significant changes to the federal EA process that is currently in place.[72] These recommendations include:

- *Impact Assessments*: The Panel recommends that EAs be replaced by "Impact Assessments" (IAs), which would move beyond an assessment of environmental impacts to an all-encompassing assessment where sustainability is the central focus.[73]

- *Impact Assessment Commission*: The Panel recommends that IAs should be managed by a single, quasi-judicial tribunal, referred to as the Impact Assessment Commission (Commission). The role of the Commission would be significantly broader than the role of current responsible authorities, with the Commission assuming many of the responsibilities now undertaken by proponents in EAs. In particular, the Commission would lead all phases of the IA and have the power to develop policies and procedures for the conduct of an IA, be responsible for preparing the IA document based on studies conducted by various parties (including the proponent and Indigenous groups), have powers to address disputes that arise in the course of an IA, have powers to retain scientists to provide technical expertise, and be responsible for a decision on the IA. A project committee would also be established for each project along with a government expert committee, which would be involved in most phases of the IA.[74]

- *Projects Triggering IA Process*: A new list of projects that trigger a federal IA should be prepared (Project List), which the Panel anticipates would increase the number of assessments from dozens of projects annually to hundreds of projects annually (compared to thousands of projects annually under the predecessor to *CEAA, 2012*). The Panel has left the development of this list to the federal government, but states that federal IAs should be conducted for projects, plans, or policies with clear links to matters of federal interest, which include fish, migratory birds, species at risk, navigation and shipping, nuclear energy, cross-border activities, and Indigenous peoples and lands. The likelihood of consequential impacts on matters of federal interest should determine whether an IA is required, and projects requiring an IA would be set out in the Project List. Projects that are not on the list could still require an IA if they met prescribed criteria or if a request was made and accepted by the Commission.[75]

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70 Government of Canada, "Environmental Assessment Processes," online: <https://www.canada.ca/en/services/environment/conservation/assessments/environmental-reviews/environmental-assessment-processes.html>.

71 *Ibid*.

72 Minister of Environment and Climate Change, Expert Panel, *Building Common Ground: A New Vision for Impact Assessment in Canada*, online: <https://www.canada.ca/en/services/environment/conservation/assessments/environmental-reviews/environmental-assessment-processes/building-common-ground.html>.

73 *Ibid*, s 1.2.

74 *Ibid*, ss 3.1.2–3.1.3.

75 *Ibid*, ss 2.1.1, 3.2.1.

- *Participation of Indigenous Groups*: The role of Indigenous peoples in a federal IA would be significantly increased from the current EA process to ensure that Indigenous peoples are included in decision-making at all stages of IA. This would include greater integration of Indigenous knowledge in all phases of an IA, Indigenous representation on project and government expert committees, and enhanced capacity funding programs to ensure that Indigenous groups can meaningfully participate in IAs. The Commission would also take a leading role on consultation with Indigenous groups, which would reduce the Crown's current degree of reliance on proponents for consultation. The Panel's discussions of Indigenous issues makes reference to incorporating principles from the United Nations Declaration of the Rights of Indigenous Peoples, including free, prior, and informed consent. While it is not a formal recommendation, the Panel states that the new IA regime should be based on "collaborative consent" with dispute resolution processes available at various stages of decision-making. The Panel states that Indigenous groups should have the right to withhold consent on the IA at the Decision Phase (discussed further below) and, if they do, any party could request the Commission to refer the matter to a review panel to determine whether the withholding of consent is reasonable.[76]

- *Impact Assessment Process*: The IA process would start earlier than the current EA process, with a detailed Planning Phase led by the Commission that defines the scope of the IA, followed by a Study Phase during which all required studies are completed. This would be followed by a Decision Phase during which a decision would be based on the overall net benefit of a project for present and future generations, taking into account all gathered information and with a focus on sustainability. After applying a sustainability test, the Commission would request that Indigenous groups provide their consent on the decision. If consent was not provided, the Commission would ask a Review Panel to determine whether the withholding of consent was reasonable. The new process would incentivize consensus decision-making, as a Review Panel would also be appointed to make the IA decision if there were "important issues of non-consensus" after the Commission-led process. The Commission's decisions should also be subject to an appeal to the Governor in Council.[77]

- *Federal-Provincial Cooperation*: The Panel proposes that the federal and provincial governments should coordinate IAs where the project impacts areas beyond federal authority. This recommended approach would require significant government resources and could result in increased assessment costs for proponents, as well as longer assessment processes and greater uncertainty around the outcomes.[78]

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76 *Ibid*, s 2.3.
77 *Ibid*, s 3.
78 *Ibid*, s 2.2.

2. RECOMMENDATIONS OF THE STANDING COMMITTEE ON FISHERIES AND OCEANS, AND OF THE STANDING COMMITTEE ON TRANSPORTATION, INFRASTRUCTURE AND COMMUNITIES

The review of the *Fisheries Act* and the *NPA* began in October 2016, the purpose of which is to restore any lost protections and introduce modern safeguards.[79] The Minister of Fisheries, Oceans and the Canadian Coast Guard, along with the Minister of Transport, asked the House of Commons Standing Committee on Fisheries and Oceans (the Fisheries and Oceans Committee) and the Standing Committee on Transport, Infrastructure and Communities (the Transport Committee) to examine changes to the *Fisheries Act* and the *NPA*, respectively, that were made in 2012. The Report of the Fisheries and Oceans Committee on the *Fisheries Act* was released on 24 February 2017.[80] The Transport Committee released its report on 23 March 2017.[81]

The *Fisheries Act* is the primary federal statute governing fisheries resources in Canada and includes provisions for conserving and protecting fish and fish habitats. The *Fisheries Report* sets out 32 recommendations to the federal government following its review of the 2012 changes to the *Fisheries Act*. Among the key recommendations of the Fisheries and Oceans Committee are:

- That the concept of "serious harm" to fish be removed from the *Act*, and that section 35(1) of the *Fisheries Act* return to its wording as of 29 June 2012 which reads: "No person shall carry on any work, undertaking or activity that results in the harmful alteration or disruption, or the destruction, of fish habitat."[82]

- That Fisheries and Oceans Canada (DFO) take an ecosystem approach to protection and restoration of fish habitats so that the entire food web is preserved for fish by adopting key sustainability principles, and by protecting the ecological integrity and key areas of fish habitats.[83]

- That any revision of the *Fisheries Act* should review and refine the previous definition of the "the harmful alteration, disruption or destruction of fish habitat" — or "HADD" — due to its vulnerability to being applied in an inconsistent manner and the limiting effect it had on government agencies in their management of fisheries and habitats in the interest of fish productivity.[84]

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79 Government of Canada, "Review of Environmental and Regulatory Processes," online: <https://www.canada.ca/en/services/environment/conservation/assessments/environmental-reviews.html>.

80 House of Commons, Standing Committee on Fisheries and Oceans, *Review of Changes Made in 2012 to the* Fisheries Act*: Enhancing the Protection of Fish and Fish Habitat and the Management of Canadian Fisheries* (February 2017) (Chair: Scott Simms), online: <www.ourcommons.ca/DocumentViewer/en/42-1/FOPO/report-6> [*Fisheries Report*].

81 House of Commons, Standing Committee on Transport, Infrastructure and Communities, *A Study of the* Navigation Protection Act (March 2017) (Chair: Judy Sgro), online: <www.ourcommons.ca/DocumentViewer/en/42-1/TRAN/report-11> [*NPA* Report].

82 *Fisheries Report*, *supra* note 80 at 13.

83 *Ibid*.

84 *Ibid*.

- That protection from harmful alteration, disruption, or destruction of fish habitat "be extended to all ocean and natural freshwater habitats to ensure healthy biodiversity."[85]

- That fish habitat be protected from key activities that can damage them, such as destructive fishing practices, and the cumulative effects of multiple activities.[86]

- That the *Fisheries Act* include a clear definition of what constitutes a fish habitat.[87]

- That DFO clearly define the parameters of what is considered a violation of the *Fisheries Act*.[88]

- That the Minister's mandate be broadened to "consider long-term conservation and protection of fish and fish habitat when evaluating projects that contravene the *Fisheries Act*."[89]

- That DFO provide the Committee with a report within two years after the revision to the *Fisheries Act* detailing authorization requests and decisions timelines.[90]

- That any changes to habitat protection in the *Fisheries Act* must be supported by a reduced reliance on project proponent self-assessment.[91]

- That DFO make investments into a public and accessible database system that will identify:

    1. The location and status of projects that have been flagged by [DFO] as having a potential to cause harm to fish and fish habitat (authorizations, monitoring results and convictions) and their cumulative effects;

    2. The location of different aquatic species;

    3. Up-to-date monitoring of aquatic species at risk and their status; and

    4. The status of authorizations.[92]

- That DFO re-establish the Habitat Protection Branch, and provide it with adequate resources to provide advice to proponents of projects that may impact marine and freshwater habitats, and to enforce compliance.[93]

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85 *Ibid* at 14.
86 *Ibid*.
87 *Ibid* at 15.
88 *Ibid* at 16.
89 *Ibid* at 17.
90 *Ibid* at 18.
91 *Ibid* at 20.
92 *Ibid* at 21–22.
93 *Ibid* at 24.

- That the section 32, 35, and 36 *Fisheries Act* authorizations be re-examined as environmental assessment triggers.[94]

- That the Minister, in the exercise of his or her discretionary power over licensing, "may specify conditions of licence respecting and in support of social and economic objectives, in addition to the conservation objectives currently identified."[95]

- That DFO renew its commitment to the "No Net Loss" and "Net Gain" policies with renewed focus, effort, and resources on restoration and enhancement of fish habitat, and fish productivity, and that the department allow project proponents flexibility to fulfil this requirement.[96]

The *Fisheries Report* also calls for DFO to provide additional resources for monitoring, compliance, and enforcement purposes, as well as improved communications between fisheries stakeholders and DFO upper management and decision-makers. At this time, there is no indication of which recommendations will be adopted by the federal government, however the federal government has proposed in its June 2017 discussion paper (see below) that lost protections be restored in the *Fisheries Act* and *NPA*.

The Transport Committee undertook a study of the changes made to the *NPA* in 2009 and 2012, with a focus on the environmental and sector impact of the changes, as well as the cost and practicality of the changes within the context of the environmental, business and recreational functions of Canada's waterways. The *NPA* Report sets out 11 recommendations including, among other things, maintaining the current Schedule to the *NPA* and establishing user-friendly mechanisms to add waterways to the Schedule, including Transport Canada in the EA decision-making process for pipelines and electrical transmission lines that cross navigable waters, establishing more clearly articulated criteria for the aqueous highway test, requiring project proponents to adequately inform stakeholders before commencing work, and establishing an efficient administrative complaint mechanism to resolve possible impediments to navigation.[97]

3. NATIONAL ENERGY BOARD MODERNIZATION AND REVIEW

On 15 May 2017, the expert panel on the modernization of the NEB released its report to the federal government.[98] The review process was started in June 2016 to help restore public

94 *Ibid* at 25.
95 *Ibid* at 33.
96 *Ibid* at 37. For a complete list of the Committee's recommendations, see the *Fisheries Report*, *supra* note 80 at 41–45.
97 *NPA* Report, *supra* note 81.
98 Expert Panel on the Modernization of the National Energy Board, *Forward, Together: Enabling Canada's Clean, Safe, and Secure Energy Future*, online: <https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/pdf/NEB-Modernization-Report-EN-WebReady.pdf>.

confidence in NEB processes.[99] The expert panel was tasked with reviewing and providing recommendations on the NEB's governance and structure, mandate and future opportunities, decision-making roles, enforcement powers, engagement with Indigenous groups, and public participation. As articulated by the expert panel in its report, the key elements of the modernization of the NEB include the following:

- A regulatory system that aligns with a clearly defined and coherent national strategy.
- A new, independent Canadian Energy Information Agency that is separate from both policy and regulatory functions.
- Replacement of the NEB with a modern Canadian Energy Transmission Commission.
- A one year process to determine alignment with national interest for all major projects, followed by detailed project review or licensing decisions.
- A full environmental assessment and licensing by a two-year Joint Canadian Energy Transmission Commission and *CEAA* Hearing Panel process.
- Real and substantive participation of Indigenous peoples.
- An increased scope of stakeholder engagement, as well as better relationships with landowners.[100]

The public comment period for the expert panel's report on the NEB closed on 14 June 2017.

4. FEDERAL GOVERNMENT RELEASES DISCUSSION PAPER ON REVIEW OF ENVIRONMENTAL AND REGULATORY PROCESSES

On 29 June 2017, the federal government released a discussion paper which outlines potential reforms being considered to rebuild confidence and to modernize Canada's environmental and regulatory processes.[101] Key measures being considered include:

- Establishing a single government agency responsible for assessments of federally designated projects. The review would go beyond environmental impacts to also consider social, health, and economic aspects of a project and require a gender-

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[99] One of the main concerns that was raised when the review of the NEB was announced was how projects currently being assessed would be affected. To address this, the federal government announced in January 2016 that an interim set of five principles would apply to these projects to help transition the NEB to its new mandate. See Government of Canada, "Government of Canada Moves to Restore Trust in Environmental Assessment" (27 January 2016), online: <https://www.canada.ca/en/natural-resources-canada/news/2016/01/government-of-canada-moves-to-restore-trust-in-environmental-assessment.html>.

[100] See *supra* note 98 at 4.

[101] Government of Canada, *Environmental and Regulatory Reviews Discussion Paper* (Ottawa: Government of Canada, 2017), online: <https://www.canada.ca/content/dam/themes/environment/conservation/environmental-reviews/share-your-views/proposed-approach/discussion-paper-june-2017-eng.pdf>.

based analysis. Joint assessments will be undertaken with the life cycle regulator for major energy transmission, nuclear, and offshore oil and gas projects.[102]

- Requiring an early planning phase to foster greater collaboration and engagement between proponents, Indigenous peoples, stakeholders, the public, and federal and provincial governments.[103]

- Early and regular engagement and partnership with Indigenous peoples based on recognition of Indigenous rights and interests from the outset, seeking to achieve free, prior, and informed consent through processes based on mutual respect and dialogue.[104]

- Restoring lost protections and incorporating modern safeguards to the *Fisheries Act* and the *NPA*.[105]

The public comment period on the discussion paper closed on 28 August 2017. The federal government has indicated that this discussion will inform proposed changes to Canada's environmental assessment and regulatory processes in the fall of 2017 or early 2018.

B. QUEBEC

1. *MODERNIZATION OF ENVIRONMENT QUALITY ACT*

The Quebec government introduced Bill 102[106] into the National Assembly on 7 June 2016, which looks to modernize the environmental authorization scheme established under the Quebec *Environment Quality Act*.[107] In particular, Bill 102 contains provisions to streamline the provincial environmental authorization process, including the environmental impact assessment (EIA) and review process for major energy projects. Bill 102 would also allow the Quebec government to subject any project to the EIA process if it: (1) raises major environmental issues and public concern warrants it; (2) involves a new technology or new type of activity in Quebec whose anticipated impacts on the environment are significant; or (3) involves major climate change issues.[108] Furthermore, Bill 102 seeks to facilitate public access to various environmental and permitting documents. Bill 102 was adopted on 23 March 2017 and is scheduled to come into force on 23 March 2018.

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102 *Ibid* at 13.
103 *Ibid* at 18.
104 *Ibid* at 15.
105 *Ibid* at 4.
106 *An Act to amend the Environment Quality Act to modernize the environmental authorization scheme and to amend other legislative provisions, in particular to reform the governance of the Green Fund*, 1st Sess, 41st Leg, Quebec, 2016.
107 CQLR c Q-2 [*EQA*].
108 *Supra* note 106, s 19.

IV. OIL AND GAS

A. FEDERAL

1. PROPOSED MORATORIUM ON OIL TANKERS ON THE NORTHERN BRITISH COLUMBIA COAST

On 29 November 2016, the federal government announced that it will implement a moratorium on crude oil tankers on the northern part of British Columbia's coast to supplement the current voluntary Tanker Exclusion Zone (TEZ).[109] The government plans to introduce legislation in spring 2017 to formally implement the moratorium. While details of the moratorium are still pending, the federal government has stated that the moratorium will:

- extend from the border between British Columbia and Alaska to the location on British Columbia's mainland adjacent to the northern tip of Vancouver Island, inclusive of Haida Gwaii, but will not extend as far away from the coast as the TEZ;

- apply to the shipment of crude oils and related oil products that dissipate slowly when spilled;

- not apply to vessels carrying less than 12,500 tonnes of crude oil or persistent oil products as cargo; and

- be enforced by penalty provisions of up to $5 million.[110]

The government intends to list the substances subject to the moratorium in the enacting legislation. Indications from the federal government are that the moratorium will apply to crude oil as defined in the *International Convention for the Prevention of Pollution from Ships*, namely:

> "Crude oil" means any liquid hydrocarbon mixture occurring naturally in the earth whether or not treated to render it suitable for transportation and includes:

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109 In 1985, Canada created a voluntary TEZ along the entire coast of British Columbia to reduce the likelihood that an oil spill would affect British Columbia's shoreline. The TEZ is designed to prevent loaded oil tankers travelling between Alaska and the continental United States from travelling close to British Columbia's shoreline. The size of the TEZ was designed to ensure that any ship would receive assistance before any oil spilled by that ship reached British Columbia's shoreline. The TEZ typically extends about 70 nautical miles off of British Columbia's coast, but narrows to about 25 nautical miles at the southern end of Vancouver Island. The TEZ does not apply to tankers travelling to or from Canadian ports or tankers in ballast. For more information, see Transport Canada, "Safe Routing, Reporting and Restrictions for Vessels," online: <https://www.tc.gc.ca/eng/marinesafety/safe-routing-reporting-vessels-4516.html>.

110 Transport Canada, News Release, "Crude Oil Tanker Moratorium on British Columbia's North Coast" (12 May 2017), online: <https://www.canada.ca/en/transport-canada/news/2017/05/crude_oil_tankermoratoriumonbritishcolumbiasnorthcoast.html>.

(1) crude oil from which certain distillate fractions may have been removed; and

(2) crude oil to which certain distillate fractions may have been added.[111]

B. BRITISH COLUMBIA

1. UPDATE ON LIQUIFIED NATURAL GAS

Given the continuing challenges faced by the global energy industry, proposed liquefied natural gas (LNG) projects in British Columbia are also facing continued uncertainty as a result. While the British Columbia government has established the foundation for a regulatory framework for the development of their LNG industry, only one project proponent — Woodfibre LNG Limited — has announced that it will move forward with its proposed facility in Squamish, British Columbia.[112] As of October 2017, there were 17 LNG export proposals in British Columbia at various stages of development.[113] To date, four LNG project proponents have received both provincial and federal environmental assessment approvals including Woodfibre LNG, Kitimat LNG, LNG Canada, and Pacific Northwest LNG. In July 2017, Pacific NorthWest LNG announced that it will not be proceeding with the development of its LNG project in the District of Port Edward.[114] A final investment decisions on LNG Canada's proposed LNG facility in Kitimat[115] may be announced in 2018.

C. ALBERTA

1. REGULATORY IMPACTS OF *REDWATER ENERGY CORPORATION (RE); ORPHAN WELL ASSOCIATION V. GRANT THORNTON LIMITED*

On 24 April 2017, the Alberta Court of Appeal released its decision on the matter of *Orphan Well Association v. Grant Thornton Limited*,[116] affirming the reasoning of the Court of Queen's Bench,[117] which was likely the most significant decision in 2016 for the oil and gas sector. *Redwater* brought bankruptcy and insolvency issues to the fore, and led to the issuance of two bulletins by the Alberta Energy Regulator (AER) in response to the trial decision. The key issue in *Redwater* relates to the allocation of environmental responsibilities during bankruptcy proceedings. Although the AER has endeavoured to contain these issues

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111 *International Convention for the Prevention of Pollution from Ships, 1973, as amended by the Protocol of 1978*, 17 February 1978, online: <https://treaties.un.org/doc/Publication/UNTS/Volume%201340/volume-1340-I-22484-English.pdf> [MARPOL 73/78]. Most aspects of the MARPOL 73/78 have been adopted under the *Canada Shipping Act, 2001*, SC 2001, c 26.

112 Woodfibre LNG Limited's Squamish facility, which announced its positive final investment decision in November 2016, has received a licence to export approximately 2.1 million tonnes of LNG per year for 40 years. See online: Woodfibre LNG <https://www.woodfibrelng.ca/the-project/about-the-project/>.

113 See Government of British Columbia, "LNG in BC," online: <https://lnginbc.gov.bc.ca/tile/bc-lng-projects/>.

114 See Pacific NorthWest LN, Media Release, "Pacific NorthWest LNG Project Not Proceeding" (25 July 2017), online: <https://www.pacificnorthwestlng.com/media/NewsRelease-Backgrounder-PNWLNG-July25-2017.pdf>.

115 The proposed LNG Canada facility in Kitimat will initially consist of two LNG processing units (referred to as trains), each with the capacity to produce 6.5 million tonnes of LNG annually; there is potential to expand the project to four trains in the future. See online: LNG Canada <https://www.lngcanada.ca/about-lng-canada/about-the-facility>.

116 2017 ABCA 124, [2017] 6 WWR 301 [*Redwater*] (known as *Redwater Energy Corporation (Re)* at the trial level).

117 2016 ABQB 278, [2016] 11 WWR 716.

by instituting stricter financial requirements on licensees under its regime, and to mandate its own priority as a creditor with respect to environmental obligations, the Court of Appeal in *Redwater* has overridden the AER by upholding the ability of trustees to disclaim assets and their attendant environmental duties, thereby preserving the primacy of secured creditors under the *Bankruptcy and Insolvency Act*.[118]

a. AER Rules Pre-*Redwater*

Prior to the *Redwater* decision, the AER instituted a series of new rules starting in 2013, with the intention of promoting greater financial health amongst the licensees governed by its regime. The AER broadened the definition of deemed costs, narrowed the scope of deemed revenues, and shortened the period for averaging industry setbacks, in order to give itself a clearer indication as to whether a given licensee had the resources to obtain new licences without entering financial hardship and risking stranding its assets.[119] These factors helped the AER assign each operator a Liability Management Rating (LMR), which demonstrates an operator's ratio of deemed assets to deemed liabilities. Prior to *Redwater,* licensees were required to have an LMR of 1.0 or greater when transferring a licensed asset to another party, and the transferee was not allowed to have their LMR drop below 1.0 as a result of the transaction. If this outcome could not be avoided, the licensee could post security to guarantee its own financial viability during the transaction.[120]

On 8 April 2016, the AER issued "Bulletin 2016-10," which reaffirmed the obligations of directors and officers of licensees, including their duty to ensure continuing care of the licensed properties, respond to incidents or complaints, maintain records, obtain AER approval for the transfer of licences, and to abandon and reclaim properties licensed under the regime to standards prescribed by the AER.[121] The Bulletin also reminded directors and officers of the enforcement mechanism available to the AER in respect of those duties, as set out by section 106 of the *Oil and Gas Conservation Act*,[122] namely that the AER may investigate and pursue available enforcement (including fines, imprisonment or both) against the licensee and its directors and officers, under sections 223 and 232 of Alberta's *Environmental Protection and Enhancement Act*.[123] Notably, the expanded reach of section 106 of the *OGCA* beyond the *EPEA* means that directors and officers may be prevented from being able to hold licences in the future, and companies with any individuals who are subject to section 106 declarations in a majority shareholder, director, or officer position may also be prevented from being able to hold or acquire new licences.[124]

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118 RSC 1985, c B-3 [*BIA*].

119 Nigel Bankes, "The Power of a Trustee in Bankruptcy to Disclaim Unproductive Oil and Gas Properties and the Implications for the AER's Liability Management Program" (17 June 2016), *ABlawg* (blog), online: <https://ablawg.ca/2016/06/17/the-power-of-a-trustee-in-bankruptcy-to-disclaim-unproductive-oil-and-gas-properties-and-the-implications-for-the-aers-liability-management-program> [Bankes, "Power of a Trustee"].

120 *Ibid.*

121 Alberta Energy Regulator, "Bulletin 2016-10" (Calgary: AER, 2016), online: <https://www.aer.ca/documents/bulletins/Bulletin-2016-10.pdf> [AER, "Bulletin 2016-10"].

122 RSA 2000, c O-6 [*OGCA*].

123 RSA 2000, c E-12 [*EPEA*]; AER, "Bulletin 2016-10," *supra* note 121.

124 The AER may make a declaration pursuant to section 106 of the *OGCA* where: (1) an AER order has been contravened or there is an outstanding debt to the AER; (2) the individual has, or had, direct or indirect control over the company at the time of contravention; and (3) it is in the public interest to do so (*OGCA*, *supra* note 122, s 106(1)). In issuing a section 106 declaration, the AER may impose a number of terms and conditions, ranging from prohibiting the named director or officer from acting as

Bulletin 2016-10 reinforced previous AER decisions, including *Re Karl*,[125] and *Re Dame*[126] which held that "[f]inancial issues are not an excuse for noncompliance with Board orders."[127] The *Karl* decision set out the test for section 106:

- Were there contraventions of or failures to comply with AER orders?
- If there was a contravention or failure, was [the] director, officer, or other person in direct or indirect control of the relevant company at the relevant time?
- If there was a contravention or failure, and [such person] was in control, is the requested declaration and order in the public interest?[128]

The public interest was defined as protection of the public and the environment, ensuring confidence in the regulatory scheme, deterring like-minded individuals from engaging in similar conduct, and serving as a warning to others who may engage in business with the named individuals.[129] Consequently, prior to *Redwater,* licensees and their directors and officers clearly owed a duty to comply with AER Board orders (particularly abandonment and reclamation orders), and were obligated to prioritize these duties over the claims of other creditors.[130]

b. The *Redwater* Decisions

The crux of the debate at both the trial and appeal levels in *Redwater* was whether abandonment and environmental liability should be considered a claim to be prioritized against an estate, or whether they should be seen not as debts but public duties existing outside of the insolvency regime. While the majority opinion on appeal decided in favour of the receiver and trustee, Grant Thornton Limited, the matter is not completely settled. Justice Martin wrote a strong and lengthy dissent, focusing on the policy implications for the province's ability to protect and manage the environment.[131] The AER has announced that it intends to file an appeal with the Supreme Court of Canada, so the debate continues.[132]

The majority opinion of the Court of Appeal confirmed that a receiver or trustee is entitled to disclaim uneconomic assets of a debtor's interest in select AER licensed properties, even though certain environmental obligations to abandon and reclaim those properties still exist. In consequence, the Court confirmed that the AER is not entitled to prohibit the transfer of licences or require the posting of security for receivers or trustees in this situation. The Court stated that under the federal *Act*, a trustee has broad power to disclaim assets, and is able to

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a director or officer in any other AER-regulated entity, to requiring the posting of additional security for any debts outstanding to the AER (including reclamation costs).

125 2015 ABAER 5, 2015 CarswellAlta 1666 [*Karl*].

126 2011 ABERCB 37, 2011 CarswellAlta 2604 [*Dame*].

127 *Ibid* at para 158.

128 *Karl*, *supra* note 125 at para 16.

129 *Ibid* at paras 128–29.

130 *OGCA*, *supra* note 122, s 103.

131 *Redwater*, *supra* note 116 at paras 107–245.

132 Alberta Energy Regulator, News Release, NR2017-06, "AER to Appeal Redwater Decision to Supreme Court of Canada" (28 April 2017), online: <www.aer.ca/about-aer/media-centre/news-releases/news-release-2017-04-28>.

"simply ignore valueless assets in the estate and turn them back to the bankrupt at the end of the insolvency process."[133]

The Court confirmed that abandonment and reclamation orders (and in effect, directives that impose security requirements on licence transfers) are provable claims in bankruptcy that enjoy no special priority under the *BIA*. It came to this conclusion by applying the three part test from *Newfoundland and Labrador v. AbitibiBowater Inc.*,[134] where the Supreme Court of Canada established the circumstances in which environmental reclamation or abandonment orders will qualify as "claims" under bankruptcy and insolvency laws: (1) there must be a debt, liability, or obligation to a creditor; (2) the debt, liability, or obligation must be incurred at the relevant time in relation to the insolvency; and (3) it must be possible to attach a monetary value to the debt, liability, or obligation.[135] Moreover, "the claim may be contingent, as long as it is not too remote or speculative to be included with the other claims. That depends on whether there is 'sufficient certainty' that the regulatory body will ultimately perform remediation and crystallize the claim."[136] On the latter point, the Court in *Redwater* found that environmental orders of the AER were provable claims either because the obligation to remediate "arises directly from a cleanup order, or indirectly from a Directive which imposes financial consequences on the transfer of assets. The [AER's] policy on transfers essentially strips away from the bankrupt estate enough value to meet the outstanding environmental obligations."[137]

Justice Martin, dissenting, took a very different approach from the majority by considering all three parts of the *AbitibiBowater* test. Even though the AER had already conceded on appeal that it was a creditor for the purposes of the test, Justice Martin disagreed, finding that provincial regulatory regimes governing abandonment and reclamation obligations and licence transfers constitute an ongoing obligation that persists throughout a bankruptcy and is not intrinsically "monetary" in nature.[138] Justice Martin's analysis was organized on the principle of "co-operative federalism,"[139] which means that federal and provincial laws should be interpreted, whenever possible, as harmonious with one another "so that each level of government may act as freely as possible within its respective sphere of authority."[140] On this basis, even though compliance with the provincial regime would have the effect of reducing recovery for creditors, in her view, there would be no reordering of claims under the federal legislation because "[t]he end of life obligations associated with licensed assets, being compliance costs to generally applicable laws, are factored in to the lender's risk assessment and its decision to lend on the strength of the debtor's collateral."[141]

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133 *Redwater*, *supra* note 116 at para 70.
134 2012 SCC 67, [2012] 3 SCR 443 [*AbitibiBowater*].
135 *Ibid* at para 26.
136 *Redwater*, *supra* note 116 at para 60. See also Nigel Bankes, "Majority of the Court of Appeal Confirms Chief Justice Wittmann's *Redwater* Decision" (3 May 2017), *ABlawg* (blog), online: <https://ablawg.ca/2017/05/03/majority-of-the-court-of-appeal-confirms-chief-justice-wittmanns-redwater-decision>.
137 *Redwater*, *ibid* at para 77.
138 *Ibid* at paras 166–88.
139 *Ibid* at paras 114, 150.
140 *Alberta (Attorney General) v Moloney*, 2015 SCC 51, [2015] 3 SCR 327 at para 27, cited in *Redwater*, *ibid* at para 150.
141 *Redwater*, *ibid* at para 239.

c. AER Rules Post-*Redwater* Trial Decision

Since the Alberta Court of Queen's Bench decision on *Redwater,* the AER has issued two bulletins. Issued on 20 June 2016, Bulletin 2016-16 declared that all transferees of licences must henceforth maintain an LMR of 2.0 or greater in order to effect the transfer.[142] This was a response to the expected outcomes of the *Redwater* decision, namely that a greater number of assets were likely to be renounced by trustees during bankruptcy, resulting in an increase in orphan wells. The AER felt that by imposing more stringent requirements on licensees, they were less likely to undertake transfers that would risk their solvency. The Bulletin also increased the AER's discretion to determine eligibility under *Directive 067: Applying for Approval to Hold EUB Licences*,[143] including giving it an expanded ability to either refuse an application or impose terms and conditions on the licence. Additionally, it gave the AER the power to require evidence that there has been no material change for holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications). Applicants may now be compelled to produce evidence that they hold adequate insurance and that the directors, officers, and shareholders are substantially the same as when licence eligibility was originally granted.[144] Bulletin 2016-21[145] was issued on 8 July 2016 and substantially upheld the interim measures of Bulletin 2016-16, but with the modification that the AER is now allowed to consider evidence provided by the applicant demonstrating that "they are able to satisfy the AER by other means that they will be able to meet their obligations throughout the life cycle of energy development with an LMR of less than 2.0."[146]

In light of the *Redwater* decision, there is uncertainty about how the revised AER policy will play out in terms of economic imperatives. On the one hand, there are several benefits for creditors that are apparent. In particular there is greater certainty in how their claims will be prioritized vis à vis the AER and the Orphan Well Association (OWA), and so producers' access to credit is accordingly more assured. However, there are some potential negative repercussions from *Redwater* from the view point of smaller operators, the AER, and the public. First, in response to the potential for an increased number of orphaned wells as a result of the *Redwater* decision,[147] expensive levies in the form of two $15 million tranches in the 2017–2018 year will add additional financial pressure to operators, thereby increasing the risk that more companies will become insolvent.[148]

Second, it does not seem readily apparent that the AER's new policy of imposing an LMR of 2.0 on transferees will avoid a *Redwater* scenario. The theory behind the LMR scheme is

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142 Alberta Energy Regulator, "Bulletin 2016-16" (Calgary: AER, 2016), online: <https://www.aer.ca/documents/bulletins/Bulletin-2016-16.pdf>.

143 Alberta Energy and Utilities Board, *Directive 067: Applying for Approval to Hold EUB Licences* (Calgary: AEUB, 2005), online: <https://www.aer.ca/documents/directives/Directive067.pdf>.

144 *Supra* note 142.

145 Alberta Energy Regulator, "Bulletin 2016-21" (Calgary: AER, 2016), online: <https://www.aer.ca/documents/bulletins/Bulletin-2016-21.pdf>.

146 *Ibid* at 2.

147 It is impossible to say how the dramatic increase in orphaned wells in Alberta caused by the downturn in commodity prices has been aggravated by the *Redwater* decision; see Reid Southwick, "Inventory of Abandoned Oil and Gas Wells Doubles in 2016," *Calgary Herald* (28 December 2016), online: <calgaryherald.com/business/energy/inventory-of-abandoned-oil-and-gas-wells-doubles-in-2016>.

148 Alberta Energy Regulator, "Bulletin 2017-04" (Calgary: AER, 2017), online: <https://www.aer.ca/rules-and-regulations/bulletins/bulletin-2017-04> .

that assets will be available if a certain ratio of assets to debts is maintained, if and when abandonment or reclamation activities need to be carried out. However, if a bankruptcy occurs, by definition the asset to liability ratio no longer provides for funds that can carry out these activities. All the program may do is encourage licensees to be fiscally prudent in taking on debt if they hope to acquire any new licences.[149] There is also the risk that transfers of AER licensed assets will slow, driving down the value of properties held by companies with an LMR below 2.0, as well as reduce the number of potential buyers of assets, deterred by the obligation to provide increased security deposits.[150] That said, the AER has taken a pragmatic approach, and is considering applications to approve transfers where the transferee will have an LMR less than 2.0 on a case by case basis where the transferee has been able to provide assurances to the AER that it will honour its abandonment and reclamation obligations.

Third, and most importantly, the debate on who should bear the environmental burdens left behind by bankrupt oil and gas companies has been settled, at least for now, in favour of banks and other creditors. Rather than take on special or superior status as a creditor in light of the public nature of unremediated oil and gas facilities, the AER and the OWA have a simple provable claim like any other against the estate of the company in receivership. Funds available to these entities are likely to be quite limited.[151] Furthermore, the finding of the Court contradicts the "polluter pays" principle, which has been adopted as a guiding principle in Canadian environmental law and enshrined in many pieces of legislation.

2. *ERNST V. ALBERTA ENERGY REGULATOR*

A potentially high stakes case for regulators was addressed in January 2017 by the Supreme Court of Canada in *Ernst v. Alberta Energy Regulator*,[152] which considered whether a judicial or quasi-judicial decision-maker such as the AER could be sued for violating an individual's freedom of expression rights in section 2(b) of the *Canadian Charter of Rights and Freedoms*.[153] Unfortunately, the Supreme Court was not able to agree on an answer to this question and split 4-4-1 in its decision, ultimately denying the plaintiff's claim for damages.

a. Background

Jessica Ernst was warned not to communicate with the press while she participated in a complaint process over the AER's decision to allow hydraulic fracturing near her property. Ultimately, the AER ceased communications with her for a 16-month period from 2005 to 2007. She commenced proceedings against the AER, alleging that its actions violated her section 2(b) rights by disqualifying her from lodging complaints, registering concerns, or participating in the compliance and enforcement process, thereby qualifying her for damages under section 24 of the *Charter*.[154]

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149 Bankes, "Power of a Trustee," *supra* note 119.
150 *Ibid*.
151 *Ibid*.
152 2017 SCC 1, 405 DLR (4th) 244 [*Ernst*].
153 Part I of the *Constitution Act, 1982*, being Schedule B to the *Canada Act 1982* (UK), 1982, c 11 [*Charter*].
154 *Ernst*, *supra* note 152 at para 6.

The main issue before the Supreme Court was whether *Charter* damages could be awarded to Ernst, however, the Justices of the Supreme Court variously engaged with several sub-issues, including (1) whether the decision of the Board to cease communications with Ernst violated her section 2(b) rights;[155] (2) whether section 43 of the *Energy Resources Conservation Act*[156] barred her claim to damages under the *Charter*; (3) whether *Charter* damages could be a just and appropriate remedy in the circumstances; (4) whether section 43 of the *ERCA* was constitutional for purporting to bar Ernst's right to *Charter* damages; and (5) whether her failure to provide proper notice of her constitutional challenge to section 43 could be a bar to her claim.

b. Decision

Justices Cromwell, Karakatsanis, Wagner, and Gascon concluded that section 43 was an absolute bar to Ernst's claims, while Justice Abella decided that failure to provide full notice of the constitutional claim was an insurmountable obstacle. The Chief Justice, along with Justices Moldaver, Brown, and Côté, dissented in the result. On the issue of whether Ernst was barred from bringing her claim by section 43 of the *ERCA*, Justices Cromwell and Abella took it as fact that section 43 barred Ernst's claim, mainly on the basis that she herself had admitted it to be so.[157] Justice Cromwell did acknowledge that he was not bound by Ernst's declaration, although he noted there was no authority to support taking a contrary position. He decided that to hold otherwise would have been unfair to the AER as it had not made submissions on this point.[158]

Another matter under consideration was whether section 43 was in and of itself unconstitutional for purporting to bar an otherwise genuine claim to *Charter* damages. To answer the question on *Charter* damages, the Supreme Court relied on *Vancouver (City) v. Ward*[159] and concluded that they could never be an appropriate remedy in this case, or any other.[160] Even though the first stage of the *Ward* test asks whether *Charter* damages could be appropriate for vindication and deterrence purposes, Justice Cromwell proceeded directly to the second stage of the test, which was to consider any countervailing factors that weighed in favour of barring access to *Charter* damages. On this point, Justice Cromwell dwelled on how opening up the AER to damages claims would "distract it from its statutory duties, potentially have a chilling effect on its decision making … and open up new and undesirable modes of collateral attack on its decisions."[161] Furthermore, immunity from civil claims allows decision-makers to "fairly and effectively make decisions by ensuring freedom from

155 Only Chief Justice McLachlin dealt with the substance of Ernst's *Charter* claim, finding that the facts supported the finding that Ernst had an admittedly novel but arguable section 2(b) claim (*ibid* at para 159).

156 RSA 2000, c E-10 (repealed) [*ERCA*]. Note that the *Responsible Energy Development Act*, SA 2012, c R-17.3, which replaces it, contains a very similar provision to the immunity clause described at section 43.

157 *Ernst*, *supra* note 152 at paras 10–11.

158 *Ibid* at para 16. Chief Justice McLachlin did not find this to be the case, holding that the court can, in exceptional circumstances, be compelled to consider "an issue not raised by the parties" (*ibid* at para 183). She found that those exceptional circumstances existed in Ernst's case, citing the complexity of the interaction between section 43 of the *ERCA* and section 24 of the *Charter*, the significant public importance of the issues, and the potential consequences for other cases (*ibid* at paras 183–84).

159 2010 SCC 27, [2010] 2 SCR 28 [*Ward*].

160 *Ernst*, *supra* note 152 at paras 21–23. Indeed, to conclude otherwise "largely undermines the purpose of conferring immunity in the first place" (*ibid* at para 56).

161 *Ibid* at para 55.

interference, which is necessary for their independence and impartiality."[162] The test from *Ward* also requires consideration as to whether any other remedy would be more appropriate in the circumstances. On this point, Justice Cromwell argued that Ernst's access to judicial review precluded a claim to *Charter* damages, by being a more appropriate avenue for redress of her concerns.[163] By finding that *Charter* damages could never be an appropriate or just remedy in these circumstances, Justice Cromwell concluded section 43 could not be unconstitutional if it barred access to a remedy that was not available in any event.[164]

On the issue of alternative remedies, Chief Justice McLachlin held that judicial review was not a satisfactory replacement for damages because the AER had failed to show that it would meet the same objectives as damages, specifically, vindicating Ernst's *Charter* right and deterring future breaches. She noted that under the Alberta *Rules of Court*,[165] damages are not available through judicial review.[166]

Justice Abella took the opposite approach to Justice Cromwell, in that she decided that a consideration of the constitutionality of section 43 was necessary before considering whether *Charter* damages could be a just and appropriate remedy in this case, although she did comment that she thought *Charter* damages were unlikely to ever be appropriate.[167] Ultimately, Justice Abella left it open as to whether section 43 was constitutional, however she did agree with Justice Cromwell regarding the good governance aspects of immunity provisions, and the fact that judicial review was likely to be a more appropriate remedy in any event, as it would help to clarify the right in question and ensure the breach was not committed again.[168]

On the issue of whether Ernst's failure to provide notice of the constitutional challenge was fatal to her claim, only Justice Abella definitively concluded in the affirmative, whereas Justice Cromwell and Chief Justice McLachlin remarked on the lack of notice as being problematic but not necessarily insurmountable.

The issue of whether immunity provisions are constitutional remains an open question in light of the fact that Justice Abella and Chief Justice McLachlin made no finding on this particular issue; indeed, even Justice Cromwell's decision could arguably be interpreted as leaving the question open based on the fact that he made his finding on Ernst's failure to prove otherwise.[169]

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162 *Ibid* at para 51.
163 *Ibid* at para 32.
164 Chief Justice McLachlin took an entirely different approach on the issue of *Charter* damages and the constitutionality of section 43. For her, it was unnecessary to decide whether section 43 was constitutional before deciding the matter of whether *Charter* damages could ever be an appropriate and just remedy for Ernst's novel yet viable claim (*ibid* at paras 158–60).
165 Alta Reg 124/2010.
166 *Ernst*, *supra* note 152 at para 167.
167 *Ibid* at para 123.
168 *Ibid* at paras 61–130.
169 See Jennifer Koshan, "Die Another Day: The Supreme Court's Decision in *Ernst v Alberta Energy Regulator* and the Future of Statutory Immunity Clauses for *Charter* Damages" (16 January 2017), *ABlawg* (blog), online: <https://ablawg.ca/wp-content/uploads/2017/01/Blog_JK_Ernst.pdf>.

3. INCENTIVIZING EFFICIENCY WITH ROYALTY REGIMES IN ALBERTA

While the royalty review in 2015 fostered anxiety among oil and gas stakeholders in Alberta during a period of economic uncertainty, a year later the same topic proved to be quite reassuring. Fears that a total overhaul of the royalty schemes administered by the Alberta government during the downturn in commodity prices would only further devastate the industry were allayed by the release of the Royalty Review Report (the Report) at the beginning of 2016.[170] The recommendations of the Report were adopted by the Alberta government and have been implemented in phases throughout the last twelve months. The two major changes suggested by the Report and implemented by the Alberta government were the adoption of reduced royalty rates prior to a deemed "payout," and application of the same royalty scheme to both oil and gas to avoid the difficulties associated with categorizing some wells as one or the other.[171]

The Modernized Royalty Framework (MRF), which became effective on 1 January 2017, creates a Drilling and Completion Cost Allowance (called the C*) which is calculated for each well based on its vertical and horizontal dimensions. Drilling and completion costs per metre are then aggregated across the industry, to produce an average C* for wells of the same specifications. This is referred to as the Alberta Capital Cost Index, and is determined by the AER. The purpose of a C* is to estimate the date a producer is likely to have recovered capital costs for drilling and completion of a well, based on an industry wide average. Prior to that date, a producer is only obligated to pay a reduced 5 percent flat rate royalty on the gross revenue produced by the well. Following the well's deemed payout under C*, royalty rates will increase to up to 40 percent.[172]

Consequently, operators who can reach actual payout prior to deemed payout have the opportunity to pay minimal royalties on net revenue until deemed payout occurs. The intended result was to incentivize efficiency in the industry and penalize high-cost producers, even though this will include those who face cost overruns or other unexpected obstacles. Any producer that reaches actual payout after deemed payout will experience a period of time during which they must pay a premium royalty rate before they have paid off the operating costs and maintenance capital. The consequence will be that profitability of that well will be further delayed than under the prior regime. There was a mixed response from legal practitioners in the oil and gas industry to the MRF, with some suggestions that this regime would disproportionately affect smaller operators, causing them to abandon a well rather than risk developing it and not reach actual payout prior to deemed payout.

In July 2016, the Alberta government launched two new royalty programs under the MRF, which added nuance to the current regime by providing specialized incentives to develop areas with large resource potential that are subject to unavoidable high costs. The first was the Emerging Resources Program (ERP) which employs the same scheme based on the C*,

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170 Royalty Review Advisory Panel, *Alberta at a Crossroads: Royalty Review Advisory Panel Report* (Alberta: Wood MacKenzie, 2016), online: <www.energy.alberta.ca/Org/pdfs/RoyaltyReportJan2016.pdf>.

171 *Ibid.*

172 Government of Alberta, "About Royalties," online: <www.energy.alberta.ca/About_Us/Royalty.asp>.

described above. The difference is that wells eligible under the ERP are assigned a far more favourable cost allowance (C*ERP) than an ordinary well, with the effect that the well will enjoy a longer period of growth under the 5 percent royalty rate. The Alberta government has indicated that the C*ERP could be up to 150 percent of a normal C*, and that wells that are spudded earlier on in the new regime will benefit from a larger C*ERP than those brought into production later on in a project. Additionally, the C*ERP for each eligible well in a project is combined to calculate the capital cost allowance for all of those wells in a given project. Deemed payout will not occur until the combined revenue of the eligible wells equals the total project cost allowance, however no more than 15 percent of the wells in a project are eligible to receive this benefit.[173]

To be eligible under the ERP, a well must be at the early stage of development and be otherwise uncommercial without such intervention. When reviewing applications, Alberta Energy considers the technical and economic specifications of the project, as well as the time estimated until commerciality is reached, resource potential of the project and ultimately, what the net royalty benefit will be.[174] Proposed projects are required to have between 18 and 144 sections in surface area and peak production capacity needs to be forecasted at a minimum of 5,000 barrels of oil per day.

The other regime announced in July was the Enhanced Hydrocarbon Recovery Program (EHRP), which also came into effect on 1 January 2017. Similar to the ERP, the EHRP provides an answer to projects and wells that would not otherwise be developed due to high costs: in this case, those associated with enhanced recovery methods. The EHRP underpins the MRF's overall drive toward increased efficiency by generating incremental hydrocarbon production from existing wells. Unlike the Enhanced Oil Recovery Program which it replaced, the EHRP applies to all types of hydrocarbons, including crude oil, natural gas and natural gas liquids. Under the EHRP, companies are only required to pay a 5 percent flat royalty on hydrocarbons for a specified period. After the expiry of the initial period, they are required to pay the standard royalty rates. The EHRP parses out wells subject to tertiary recovery methods versus secondary, allocating up to 90 months for the benefit period for tertiary methods including the injection of carbon dioxide, nitrogen, and other specified chemicals into an oil or gas pool to facilitate recovery. The initial benefit period for wells subject to secondary enhancement techniques, including the injection of water or gas, are established on a case by case basis. Enrollment under the EHRP is available for two years initially, after which its terms will be subject to review in order to bring it into closer alignment with the royalty rights under the general scheme.[175]

To be eligible for participation, an applicant must receive technical approval of a scheme from the AER, the project must be an enhanced recovery scheme relying on either secondary or tertiary recovery methods, the project must produce more hydrocarbons from the pool than could be produced from the base recovery scheme for that pool, costs must be significantly greater than what would be incurred operating the base recovery scheme, there must be a net

[173] Government of Alberta, "Emerging Resources Program," online: <www.energy.alberta.ca/About_Us/4233.asp>.
[174] *Ibid*.
[175] Government of Alberta, "Enhanced Hydrocarbon Recovery Program," online: <www.energy.alberta.ca/About_Us/4232.asp>.

royalty benefit to the Crown throughout the life of the project, new schemes involving water flooding, gas cycling, or gas flooding must be located in a pool or part of a pool where these activities have not already occurred, and finally, the hydrocarbons in question must be subject to Crown title.[176]

In light of these new schemes, the Alberta government approved 158 new wells and received applications from more than 40 companies during the early opt in phase of the MRF. Fifty-five percent of western Canada's drilling fleet was active as of January 2017, as compared with 30 percent in January 2016. Rather than create added burdens on operators in a depressed economic environment, the royalty regimes in Alberta appear to have fostered efficiency and have provided a means of access to market for wells that might not otherwise have had the chance.

D. QUEBEC

1. *PETROLEUM RESOURCES ACT*

Bill 106 (*An Act to implement the 2030 Energy Policy and to amend various legislative provisions*) enacted the province's new *Petroleum Resources Act*, which will replace the existing provisions of the oil and gas regulatory regime in Quebec.[177] The *Act*, which is not yet in force, will significantly change the regulatory framework for the exploration, development, and production of oil and gas in Quebec, and marks the first time that Quebec has enacted legislation that relates solely to petroleum resource exploration and production. In particular, the *Act* is aimed at ensuring that oil and gas activities are performed in accordance with the GHG emission reduction targets established by the Quebec government. Further details of the regime will be set out in regulations.

The *Act* introduces significant regulatory changes to the oil and gas regime in Quebec, including an auction process for the award of oil and gas exploration rights. Licence holders will be required to inform the Minister of Energy and Natural Resources of any significant discovery and of any commercial discovery of oil and gas resources. The holder will also be required to submit a petroleum production project to the Quebec energy regulator (Régie de l'énergie) and apply to the Minister for a production licence within four years after any discovery, in the absence of which the Minister may revoke the exploration licence without compensation. Prior to undertaking the production or storage of petroleum, a licence holder will be required to (1) submit its project for review by, and to obtain a favourable decision from the Régie de l'énergie; (2) obtain an authorization under the *Environment Quality Act*[178] following the completion of the environmental impact assessment and review process; and (3) obtain a production or storage licence from the Minister. Any significant change to a petroleum production project will be subject to prior review and approval of the Régie de l'énergie. Under the *Act*, the Régie de l'énergie is given a key regulatory role in respect of petroleum production and storage projects in Quebec. The *Act* also provides additional permitting requirements applicable to various oil and gas-related activities, including

[176] *Ibid*.
[177] Bill 106, 1st Sess, 41st Leg, Quebec, 2016.
[178] *Supra* note 107.

geophysical or geochemical surveys, stratigraphic surveys, as well as drilling, completion, re-entry, and major maintenance work on wells. Further, the *Act* provides that licence and junction pipeline authorization holders will be subject to a strict no-fault liability regime requiring operators to indemnify any person for damages caused as a result of their work or activities, up to a liability cap to be determined by regulation.[179]

V. RENEWABLE ENERGY

A. WIND ENERGY UPDATE

1. UPDATE FROM ONTARIO AND ALBERTA

Ontario and Alberta have been following similar trajectories in the drive toward replacing carbon-intensive energy production with renewable energy. Ontario has been leading the trend on renewables since 2009 with the introduction of the *Green Energy Act, 2009*, which paved the way for a large number of wind power projects, especially in populated rural areas of the province.[180] More recently, Ontario launched its Large Renewable Procurement (LRP) program, which was meant to foster the expansion of renewable energy capacity by setting procurement targets in wind, solar, water power, and bioenergy projects.[181] Even though the second phase of the LRP was suspended in September 2016, the reason for this decision was based on declining renewable energy prices, which disincentivized the Ontario government from committing itself to anything that would shortly become uneconomical. Alberta is also in the process of instituting a renewable electricity program designed to incentivize additional energy capacity to power its grid. As a result, Alberta will likely also see a large increase in wind power projects, especially because of its optimal geographic conditions and the relatively low upfront capital investment required for these types of projects. The two cases discussed below highlight some of the issues arising from wind power approvals in Ontario and Alberta, and help to demonstrate some of the challenges proponents may face as new projects ramp up.

a. *Prince Edward County Field Naturalists v. Ontario (Environment and Climate Change)*

An Ontario Environmental Review Tribunal (ERT) decision delivered on 6 June 2016[182] dealt with the revocation of a Renewable Energy Approval (REA) from wind energy proponent Ostrander Point GP (Ostrander).[183] Under the *Environmental Protection Act*,[184] most renewable energy projects must apply for an REA from the Director appointed by the Ministry of the Environment and Climate Change.[185] A member of the public can appeal the decision to award an REA to the independent and quasi-judicial ERT, but must prove that

179 Bill 106, *supra* note 177.
180 SO 2009, c 12, Schedule A [*GEA, 2009*].
181 See online: Independent Electricity System Operator <www.ieso.ca/sector-participants/energy-procurement-programs-and-contracts/large-renewable-procurement>.
182 *Prince Edward County Field Naturalists v Ontario (Environment and Climate Change)*, 2016 CanLII 35406 (Ont ERT) [*PECFN*].
183 *Ibid*.
184 RSO 1990, c E.19 [*EPA* Ontario].
185 *Renewable Energy Approvals under Part V.0.1 of the Act*, O Reg 359/09.

the approved project would cause serious harm to human health or serious and irreversible harm to plant or animal life, or to the natural environment.[186] If an appeal is successful, the ERT may revoke or alter the decision of the Director.

On 6 June 2016 the ERT revoked Ostrander's REA upon which it relied to build its nine turbine wind farm in Prince Edward County at Ostrander Point. Ostrander had previously had its REA revoked in July 2013 due to the potential for serious harm to the Blanding's Turtle, an endangered species common to the area.[187] On appeal to the Ontario Divisional Court,[188] Ostrander scored a significant victory in overturning the revocation, given the normally high degree of deference displayed by the Divisional Court to the ERT as an expert on environmental matters.[189] The Divisional Court's decision to restore the REA was based on the failure of the opponents to show that harm was both serious and irreversible and that evidence on the size of the turtle population and its geographic distribution was lacking. Notably, the Divisional Court commented on the ERT's failure to sufficiently rely on the fact that Ostrander had successfully obtained a permit under the *Endangered Species Act, 2007* of Ontario,[190] which should have been strong evidence that the impact on the Blanding's Turtle was not serious or irreversible. To find otherwise undermined the presumption of "harmony, coherence, and consistency between statutes dealing with the same subject matter."[191] Finally, the Divisional Court found that the ERT's failure to consider alternative remedies to a revocation of the REA was unreasonable, as it had not heard separate submissions by the parties on what remedy would be appropriate in the circumstances.

Project opponents appealed the Divisional Court's decision to the Ontario Court of Appeal, which found that the opponents of the Ostrander wind farm had proven that serious and irreversible harm would occur to the Blanding's Turtle, but that the failure by the ERT to hear separate submissions on what might be an appropriate remedy was a mistake in law and therefore the matter should be remitted to the ERT for a resolution on remedy.[192] The ERT's 6 June 2016 decision on the appropriate remedy in light of its finding that serious and irreversible harm was likely to occur to the Blanding's Turtle restored its original decision to revoke the REA. In coming to this conclusion, the ERT preferred the submission of the opponents to the project, finding that the tribunal has the power to "step into the shoes" of the Director when considering the remedies available under section 145.2.1(4) of the Ontario *Environmental Protection Act* if the harm test has been met.[193] The ERT held that under this broad approach, encompassing a general consideration of the public interest and the totality of the parties' submissions on the remedy issue (particularly the failure of Ostrander to show

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186 *EPA* Ontario, *supra* note 184, ss 142.1, 145.2.1(2).

187 *PECFN*, *supra* note 182 at para 7. In this case, the ERT's decision represented the first REA appeal where the harm test had been met.

188 *Ostrander Point GP Inc v Prince Edward County Field Naturalists*, 2014 ONSC 974, 82 CELR (3d) 86 [*Ostrander*].

189 Richard J King et al, "Divisional Court Overturns Environmental Review Tribunal Decision and Allows Wind Project to Proceed" (25 February 2014), *Osler* (blog), online: <https://www.osler.com/en/resources/regulations/2014/divisional-court-overturns-environmental-review-tr>.

190 SO 2007, c 6.

191 *Ostrander*, *supra* note 188 at para 59, citing *R v Ulybel Enterprises Ltd*, 2001 SCC 56, [2001] 2 SCR 867 at para 52.

192 *Prince Edward County Field Naturalists v Ostrander Point GP Inc*, 2015 ONCA 269, 90 CELR (3d) 180.

193 *PECFN*, *supra* note 182 at paras 52, 135–44.

that its mitigation measures would be effective in preventing serious and irreversible harm to the Blanding's Turtle), the REA still should be revoked.[194]

b. AUC Decision on Grizzly Bear Creek Wind Power Project

Wind power projects in Alberta have always faced some degree of controversy, and resistance to these types of projects remains strong especially in southwest Alberta where the first wind farms were built.[195] It is likely that resistance will increase in conjunction with the anticipated influx of new wind power projects under the Renewable Electricity Program (REP). The Alberta Utilities Commission (AUC) issues approvals for new power generation projects, including wind farms. The test for approval is whether the proposed project is in the public interest, having regard to its social and economic effects, and the effects of the project on the environment.[196] Similar to the ERT in Ontario, the AUC conducts a thorough review of the potential benefits and burdens of a project with the support of expert witnesses who present their evidence in a panel format on a broad range of issues. There are limited avenues for appeal however, as the Alberta Court of Appeal may only hear matters of law or jurisdiction under section 29 of the *Alberta Utilities Commission Act*.[197]

In May 2016, the AUC approved E.ON Climate & Renewables Canada Ltd.'s Grizzly Bear Creek Project, which involved the construction of 50 wind turbines of 2.4 MW (with a total capacity of 120 MW) located south of Mannville. The application was objected to by the Grizzly Bear Coulee Protection Group (GBCPG), which consisted of 30 landowners residing in the vicinity of the proposed project. This triggered a hearing where the AUC heard from a panel of expert and lay witnesses about what the effects of the project were likely to be.[198]

Unlike its Ontario counterpart, the AUC placed great significance on the fact that the Grizzly Bear Creek project had already obtained an approval from Alberta Environment and Parks (AEP), which had been issued on the basis that the impact to the environment, especially wetlands, was permissible: "The Commission considers that sign-off from AEP is strong evidence that the project's environmental effects would be acceptable."[199]

Similar to the *Ostrander* decision, however, was the outcome of complaints made in relation to human health and noise disturbance. The AUC preferred the evidence of E.ON's noise assessment, which showed that noise caused by the wind farm would comply with the AUC's Rule 012. The Rule sets out the threshold for construction and operation noise from wind turbine facilities, which is assessed cumulatively with other current and approved

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194 *Ibid* at para 144.

195 See e.g. "Shooting Causes 'Extensive' Damage at Wind Farm in Southern Alberta," *CBC News* (9 February 2017), online: <www.cbc.ca/news/canada/calgary/wind-turbine-shooting-fort-macleod-1.3974801>.

196 *EPA* Ontario, *supra* note 184, s 47.5; Ontario, Ministry of the Environment and Climate Change, *Statement of Environmental Values*, online: <https://www.ebr.gov.on.ca/ERS-WEB-External/content/sev.jsp?pageName=sevList&subPageName=10001>.

197 SA 2007, c A-37.2.

198 *E.ON Climate & Renewables Canada Ltd. Grizzly Bear Creek Wind Power Project* (19 May 2016), 3329-D01-2016, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/3329-D01-2016.pdf> (Calgary Applications 1610717-1 and 1610717-2).

199 *Ibid* at para 340.

projects rather than on a stand-alone basis. The AUC decided that the GBCPG had not provided sufficient evidence to show that the project would cause the effects they anticipated, namely sleep disturbance, annoyance, and other health impacts.[200]

If wind projects in Alberta face increasing opposition from local communities, proponents will likely be required to engage in a "battle of experts" on a broad range of public interest issues, and potentially cover not only the costs of experts called on by local interveners, but their legal costs as well. For example, in the Grizzly Bear Creek Project, the proponent had to pay over $171,000 to cover these costs on behalf of GBCPG.[201] Section 7 of Rule 009 and the Scale of Costs found in Appendix A of Rule 009 set the parameters for making a costs decision in a facilities-related application. Section 7 states that the Commission may award costs to a local intervener if the Commission is of the opinion that the costs are reasonable and directly and necessarily related to the hearing or other proceeding, and the local intervener acted responsibly in the hearing or other proceeding and contributed to a better understanding of the issues before the Commission.[202]

That said, the AUC decision in the Grizzly Bear Creek wind power project suggests that proponents may enjoy a greater degree of certainty with regard to the outcome of their project approval if they have already secured other environmental permits or authorizations.

2. ALBERTA'S RENEWABLE ELECTRICITY PROGRAM

In November 2015, the Alberta government released its Climate Leadership Plan (the Plan), which has ushered in a new era in Alberta for renewable energy. The four pillars of the Plan are incentives for renewable generation, the phase-out of coal-fired power generation by 2030, the implementation of an economy-wide carbon price, and the implementation of an energy efficiency program.[203] To help deliver on some of these objectives, the Alberta Electric System Operator (AESO) has been given the mandate to design and implement the REP, while ensuring the electricity supply in Alberta remains reliable, that the proposed new program comports with Alberta's energy market, and that costs of renewable electricity are kept down.[204]

The REP is the framework under which Alberta will incentivize the addition of 5,000 MW of renewable energy capacity to its existing power sources by 2030. The REP will also facilitate the replacement of two-thirds of coal-fired electricity generation with renewable energy. A series of competitions will take place amongst renewable energy generators for the opportunity to provide power to Albertans through the existing price pool mechanism. Successful bidders will have a portion of their operation and maintenance costs set off by the

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200 *Ibid* at para 365.

201 *E.ON Climate & Renewables Canada Ltd. Grizzly Bear Creek Wind Power Project: Cost Award* (21 July 2016), 21513-D01-2016 at para 62, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/21513-D01-2016.pdf>.

202 Alberta Utilities Commission, "Rule 009," online: <www.auc.ab.ca/acts-regulations-and-auc-rules/rules/>.

203 Government of Alberta, *Climate Leadership Plan*, online: <https://www.alberta.ca/climate-leadership-plan.aspx>.

204 Government of Alberta, "Renewable Energy Program," online: <https://www.alberta.ca/renewable-electricity-program.aspx>.

Alberta government, in order to make their brand of energy source competitive with other non-renewable sources.[205]

In order to be eligible to participate in the first round of competition under the REP, generators must have projects that are based in Alberta, the projects must be new or expanded to ensure that currently operating (and presumably profitable) projects do not compete for funding if they do not need it, the generator must have the capacity to produce 5 MW or more, and the energy source must meet the definition of "renewable" according to Natural Resources Canada.[206] Projects must be capable of becoming operational by 2019, and must be able to utilize Alberta's current transmission infrastructure. These requirements will be revisited before subsequent rounds of competition are commenced.

The REP proposes to incentivize the generation of new capacity from renewable sources by utilizing Indexed Renewable Energy Credits or a "Contract for Difference" (IRECs). IRECs are the method by which the Alberta government purchases renewable attributes from generators.[207] Generators will place bids based on what their operation and maintenance costs are for running a project under the REP, plus a reasonable rate of return (the "strike price"). Successful bidders are then compensated by the government for any energy capacity that they sell in the price pool, which is below their strike price. Conversely, any time the pool price exceeds the generator's strike price, the generator pays the surplus amount to the government.[208] The strike price is calculated by linking 20 percent of the generator's operating and maintenance costs to Alberta's Consumer Price Index.[209] The theory is that this process will keep strike prices low due to two factors. Firstly, it is a competitive process and generators will want to bid with low strike prices in order to win a contract under the REP. Secondly, by having the Alberta government assume the risk of price pool fluctuations, more competitors will enter the bidding process, which should further drive down bid prices and maximize efficiencies.

IRECs and the projects they apply to will be governed by Renewable Energy Support Agreements (RESAs), which will be entered into between the AESO and each successful proponent generator for a term of 20 years.[210] Concurrently with the AESO's Request for Expressions of Interest for the first round of competition, the Operator also released an updated term sheet for the RESA. There are a few key terms of note for prospective bidders. For example, the Target Commercial Operation Date (Target COD) has been set at 1 December 2019.[211] The Support Period (the period that begins on commercial operation and ends 20 years after the earlier of commercial operation and the Target COD), wherein the generator may receive support payments, will be shortened accordingly if the generator fails to achieve commercial operation by the Target COD. Furthermore, a generator must achieve

205 *Ibid*.

206 *Ibid*. Natural Resources Canada lists the following as renewable energy sources: hydro energy, bioenergy, wind energy, solar energy, geothermal energy, and ocean energy. See Natural Resources Canada, "About Renewable Energy," online: <www.nrcan.gc.ca/energy/renewable-electricity/7295>.

207 Payments will be made to winning bidders on a $/MWh basis.

208 Alberta Electric System Operator, *AESO Renewable Electricity Program: Key Provisions of the Renewable Electricity Support Agreement* (31 March 2017), online: <https://www.aeso.ca/assets/Uploads/Key-Provisions-of-the-RESA-March31-2017.pdf> [RESA].

209 *Ibid* at 7.

210 *Ibid* at 1.

211 *Ibid* at 2.

commercial operation within 18 months after the Target COD has passed. Otherwise the AESO will have the option to terminate the RESA and apply for liquidated damages. Additionally, construction of the project must commence by the specified longstop date (also 1 December 2019). If construction is not commenced by this date, the AESO has the option to terminate the RESA and apply for liquidated damages. These rules effectively mean that the generators need to commence construction by 1 December 2019 and be commercially operational by 1 June 2021 in order to avoid significant liability.[212]

There are also certain pre-construction requirements a generator must satisfy before they may commence construction, including the acquisition of key AUC and other regulatory approvals and permits, delivery of a statutory declaration to the AESO confirming that sufficient secured financing is in place to see the project through to the commissioning stage, and finally, delivery of a copy of its financial model to the AESO. Failure to satisfy these requirements prior to the targeted commencement of construction date gives the AESO the option to terminate the RESA and claim for liquidated damages.[213]

It is also proposed that the RESA include certain security requirements of the generator for the entire project. The security proposed would be the equivalent of the liquidated damages, described above, for projects in the pre-commercial operation date. Following commercial operation, generators will not be required to maintain any liquid security with respect to payment obligations when the pool price exceeds the strike price. Payment obligations will be secured by means of security interests held by the AESO over the facility (including associated land rights), the proceeds from any sale of the facility, and the payment obligations to protect against default. Also of note is that senior lenders' security will have priority over the AESO security except with regard to generator payment obligations which accrue prior to termination of the RESA.[214]

Another notable provision in the RESA draft terms is curtailment. Under the original draft term sheet, generators would not be permitted to receive any payment for energy capacity that they could have produced during periods of enforced curtailment by the AESO. Under the new term sheet, the generator will receive compensation from the AESO when the cumulative amount of foregone energy due to such curtailments in a year exceeds 200 hours multiplied by the contract capacity of the applicable project. The new term sheet also sets out further details on how the AESO may limit the electrical generation of a project.[215]

The "change in law" provision has also been adjusted in the new draft term sheet, likely in response to unfolding litigation on the Power Purchase Arrangements in Alberta. Under the new term sheet, a "change in law" will entitle a generator to relief with respect to changes to "any laws, regulations, rules (including ISO rules) or orders by [the government of Alberta] or any Alberta governmental or regulatory authority (or any court in respect of such laws, regulations, rules or orders) which:

212 *Ibid* at 1–15.
213 *Ibid* at 3.
214 *Ibid* at 4.
215 *Ibid* at 8.

- are directed at the [REP], any Generator, the rules, regulations, or terms and conditions governing generators (whether or not renewable), or any RESA; or

- otherwise relate to occupational health and safety, the environment, or a sales tax,[216]

and with respect to "any interpretation, reinterpretation or administrative position relating to any such laws, regulations, rules or orders."[217] The term sheet also stipulates that any of these changes will only be considered "changes in law" if they result in the material delay of the development and construction of the facility, an increase in the costs the generator would reasonably be expected to incur, or would affect the volume of electricity which the generator can produce.[218]

The new term sheet also lists specific changes that will not result in relief for the generator, which include changes to any laws, regulations, rules or orders (including regulatory approval for generators) in relation to greenhouse gas emissions, emission performance credits, emission offsets, carbon offsets, carbon pricing, carbon-related taxes, levies or fees, or other carbon-related charges or payments. For clarity, the term sheet specifies that changes to certain Acts and their regulations which do not constitute a change in law, including the *Climate Change and Emissions Management Act*,[219] the *Climate Leadership Implementation Act*,[220] the *Oil Sands Emissions Limit Act*,[221] and the *Environment and Sustainable Resource Development Grant Regulation*.[222] The RESA also excludes any changes where the generator had prior notice of the change, where the change is in response to any action by the generator which is contrary to law, or where the change is permitted by the RESA.[223]

It should also be noted that the AESO intends to create a capacity market in addition to the energy only market. This process is expected to take three years and a capacity market is expected to be in place by 2021.[224] Alberta's electricity market will be composed of four key segments: (1) the market for energy; (2) the ancillary services market; (3) a market for capacity; and (4) the REP. The market for capacity will allow generators to be compensated for making generation capacity available on demand.[225]

216 *Ibid*.
217 *Ibid*.
218 *Ibid*.
219 SA 2003, c C-16.7.
220 Bill 20, 2nd Sess, 29th Leg, Alberta, 2016.
221 *Supra* note 27.
222 Alta Reg 182/2000.
223 RESA, *supra* note 208 at 9.
224 See Alberta Electric System Operator, "Capacity Market Transition," online: <https://www.aeso.ca/market/capacity-market-transition/>.
225 See Alberta Electric System Operator, "Capacity Market Q&A," online: <https://www.aeso.ca/assets/Uploads/CapacityMarket-QA-WEB.pdf>.

3. NEW DIRECTIVES FOR WIND ENERGY PROJECTS IN ALBERTA AND SASKATCHEWAN

In January 2017, Alberta Environment and Parks issued an updated Wildlife Directive for Alberta Wind Energy Projects.[226] The directive, which updates the 2011 Wildlife Guideline for Alberta Wind Energy Projects,[227] sets out potential wildlife issues associated with wind energy projects and provides standards and best management practices for minimizing impacts to wildlife and wildlife habitat during the siting, construction, and operation of wind farms in Alberta. AEP has also developed the following supporting documents: (1) Renewable Energy External Wind: Checklist A — Standard Approach; (2) Renewable Energy External Wind: Checklist B — Buildable Area Approach; and (3) Grandfathering Administrative Procedure: Wind Energy Review Process (which outlines the transition process from the 2011 wildlife guideline to the 2017 wildlife directive).[228]

In the fall of 2016, Saskatchewan issued the province's first Environmental Impact Assessment for a wind project, in which the Minister of Environment refused to issue the environmental approval.[229] The approval was refused mainly on the grounds that the project was going to be too close to the flight path of migratory birds. The province concurrently released the *Wildlife Siting Guidelines for Saskatchewan Wind Energy Projects*.[230] The *Guidelines* will help proponents plan their projects to ensure that they conform to provincial and federal environmental legislation. The *Guidelines* give specific direction on avoidance zones, pre-construction planning and surveying, and site level and infrastructure considerations.

B. TIDAL POWER UPDATE

1. TIDAL POWER LITIGATION IN THE BAY OF FUNDY

Although not as active an industry in Canada as wind or solar, there were some important developments in tidal power in 2016, particularly in Nova Scotia. Cape Sharp Tidal, a joint venture between OpenHydro and Nova Scotia Power affiliate Emera, received approval from the Government of Nova Scotia's Department of the Environment for the installation of two 2 MW tidal turbines in Minas Passage in the Bay of Fundy, at the test site of Fundy Ocean

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226 Alberta Environment and Parks, *Wildlife Directive for Alberta Wind Energy Projects* (Edmonton: AEP, 2017), online: <aep.alberta.ca/fish-wildlife/wildlife-land-use-guidelines/documents/WildlifeWindEnergyDirective-Apr07-2017.pdf>.

227 See online: Government of Alberta <https://open.alberta.ca/publications/wildlife-guidelines-for-alberta-wind-energy-projects>.

228 Alberta Environment and Parks, "Wildlife Land Use Guidelines," online: <aep.alberta.ca/fish-wildlife/wildlife-land-use-guidelines/>. Similar wildlife guidelines have also been issued for solar energy projects located in Alberta, currently in interim form: see Alberta Environment and Parks, "Wildlife Guidelines for Alberta Solar Energy Projects," online: <https://open.alberta.ca/publications/wildlife-guidelines-for-alberta-solar-energy-projects>.

229 Jeremy Barretto, Terri-Lee Oleniuk & Kenza Salah, "Saskatchewan Refuses Approval After First Wind Energy Project Environmental Impact Assessment" (22 September 2016), *Osler* (blog), online: <https://www.osler.com/en/resources/regulations/2016/saskatchewan-refuses-approval-after-first-wind-ene>.

230 Saskatchewan Ministry of Environment, *Wildlife Siting Guidelines for Saskatchewan Wind Energy Projects*, online: <www.publications.gov.sk.ca/documents/66/94283-wind%20siting%20Guide%20May%202017.pdf> [*Guidelines*].

Research Centre for Energy (FORCE).[231] In November 2016, Cape Sharp Tidal deployed one of its 2 MW turbines, which marks the first time renewable in-stream tidal power has been successfully generated from the Bay of Fundy. The province's Renewable Electricity Regulations and Developmental Feed-in Tariff program helped to facilitate the development of the project. The demonstration turbine powers the equivalent of about 500 Nova Scotia homes with tidal energy. A second turbine is planned for deployment in 2017 and will make Cape Sharp Tidal one of the largest generating arrays in the world.[232]

a. Project Litigation

The start date for the project's installation was delayed in 2016, partly due to the recommendation of the Canadian Science Advisory Secretariat of the Department of Fisheries and Oceans (DFO) which said that FORCE's environmental monitoring program could not operate without better baseline data from which to work. DFO also advised that Cape Sharp and FORCE had not adequately addressed the risk posed by interaction between the turbines and fish and marine mammals. FORCE and Cape Sharp eventually obtained the required approvals, including approvals from Nova Scotia's Department of the Environment in June 2016. The provincial approval was accompanied by a series of conditions, including enhanced marine mammal monitoring and contingency planning for equipment failure. In response, the Bay of Fundy Inshore Fishermen's Association (BFIFA) launched an application for judicial review[233] of the province's decision, and applied for an injunction to prevent Cape Sharp from proceeding with the installation prior to going to court.[234] Ultimately, the application was unsuccessful because the lack of baseline data collected prior to the installation of the turbines was not considered to be sufficient evidence of irreparable harm.[235]

The test for granting an injunction is that (1) there must be a serious issue to be tried; (2) the applicant will suffer irreparable harm if the injunction is not granted; and (3) the applicant will be more worse off by not getting the injunction, than the other party would be if the injunction was granted.[236] The Court was mainly concerned with the second step of the test, which was that there would be irreparable harm if the injunction was not granted. BFIFA argued that irreparable harm would be caused because the opportunity to collect the baseline data would be eliminated once the turbine was installed. Without it, there could not be any reliable studies conducted on whether changes in the numbers or behaviour of marine species could be attributed to the introduction of the turbines. In spite of this, the Court did not agree that BFIFA had established that irreparable harm would occur. The reasoning was that a baseline in a dynamic environment will only ever be a partial picture, unless it draws on data collected over a significant period of time. Furthermore, data collection for the

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231 FORCE is a not-for-profit organization which provides a test centre for in-stream tidal energy technology.

232 "Cape Sharp Tidal Generates Canada's First In-Stream Tidal Energy at FORCE," *CNW* (22 November 2016), online: <www.newswire.ca/news-releases/cape-sharp-tidal-generates-canadas-first-in-stream-tidal-energy-at-force-602465285.html>.

233 See "Local Fishermen vs Bay of Fundy Tidal on Court, Again," *Tidal Energy Today* (1 February 2017), online: <tidalenergytoday.com/2017/02/01/local-fishermen-vs-bay-of-fundy-tidal-on-court-again>.

234 *Bay of Fundy Inshore Fisherman's Association v Nova Scotia (Environment)*, 2016 NSSC 286, 6 CELR (4th) 85.

235 *Ibid* at para 57.

236 *Ibid* at para 16.

purposes of a baseline cannot necessarily separate out other factors affecting fish stocks during the data collection period. BFIFA ought to have presented "evidence of irreparable harm beyond the observation that no study performed any time after deployment could ever establish a reliable baseline for comparison purposes."[237]

As a result, the first of the two turbines was deployed in early November 2016. On 10 April 2017, Justice Robertson released her decision on BFIFA's application for judicial review, holding that the decision of the Minister to accept the Environmental Effects Monitoring Program (EEMP) as satisfaction of one of the conditions attached to the original approval of the project was reasonable, and that an adaptive management approach was satisfactory in light of the lack of baseline data.[238] Justice Robertson affirmed that it was not appropriate for the Court to review the scientific evidence provided at the decision-maker level, and that BFIFA had not adduced any evidence which would show that the decision of the Minister had been unreasonable other than the 2016 DFO Science Review of the proposed EEMP, which had mentioned that there were some "knowledge gaps"[239] in the baseline information used in the EEMP.[240] Justice Robertson noted that the ultimate conclusion of the DFO Review was that the EEMP was satisfactory, which meant that the Minister's decision to approve the project was a reasonable outcome. Finally, the Court noted that "extraordinary efforts" had been made to evaluate the risks associated with the turbine project, and that the operation of the demonstration turbines was an essential next step in understanding the risk and impacts of this type of technology.[241] Notably, the Court also acknowledged the fact that this project was being undertaken "in a climate of significant public interest in diminishing our province's dependence on fossil fuels."[242]

C. HYDRO POWER UPDATE

1. SITE C UPDATE

Site C is the third dam and hydroelectric generating station to be built on the Peace River in northeastern British Columbia. Construction work on Site C began in summer 2015 and continues to proceed, even as the project is being reviewed by the British Columbia Utilities Commission (BCUC). On 2 August 2017, British Columbia's new NDP government directed the BCUC to examine the financial impact on BC Hydro ratepayers associated with continuing, suspending, or terminating the Site C project.[243] The BCUC inquiry into Site C is following a two-stage process. The first phase consisted of fact gathering in which BC Hydro, Deloitte LLP, and members of the public made submissions of data and analysis that informed the Inquiry Panel's preliminary report published on 20 September 2017.[244] In the second phase, the panel continued its public consultation process with a series of Community

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237 *Ibid* at para 44.
238 *Bay of Fundy Inshore Fisherman's Association v Nova Scotia (Environment)*, 2017 NSSC 96, 8 CELR (4th) 155.
239 *Ibid* at para 13.
240 *Ibid* at para 29.
241 *Ibid* at para 47.
242 *Ibid* at para 50.
243 For updates, see BCUC's Site C Inquiry website, online: <www.sitecinquiry.com/>.
244 See British Columbia Utilities Commission, *British Columbia Utilities Commission Inquiry Respecting Site C: Preliminary Report to the Government of British Columbia* (Vancouver: BCUC, 2017), online: <http://www.sitecinquiry.com/wp-content/uploads/2017/10/00704_A-13_Preliminary-Report-2.pdf>.

Input Sessions across the province. The Panel's final report will be provided to the Provincial Government, as directed, on 1 November 2017. While this review is underway, BC Hvdro has indicated that project construction will continue and procurement opportunities will be posted to maintain the proiect schedule.[245]

Within the context of project litigation, 2016 saw the resolution of several high-profile legal challenges against the Site C hydroelectric dam. Two of these actions commenced with an application for judicial review of the federal and provincial governments' decision to issue environmental assessment certificates under their respective legislation. The Peace Valley Landowner Association's proceedings against the government concluded in September 2016 when the British Columbia Court of Appeal affirmed the lower Court's ruling that the decision by the Minister of the Environment was reasonable.[246] Similarly, West Moberly and Prophet River First Nations also were unsuccessful in their claim, at both the Federal Court of Appeal in January, and at the British Columbia Court of Appeal a month later.[247]

As noted above, the Peace Valley Landowner Association's application for judicial review of the province's decision to issue an environmental assessment certificate for Site C was concluded by the Court of Appeal in September 2016. The Peace Valley Landowner Association claimed that the Minister's decision was unreasonable because the Minister had not taken into consideration the Economic Recommendations of the Joint Review Panel (JRP) in its report, which contravened section 17(3)(a) of the *Environmental Assessment Act*.[248] Recommendations 46 to 49 in the JRP report essentially set out the concerns of the Panel about the economic need for the Site C dam. For example, it was recommended that the project costs be referred to the BC Utilities Commission for review, and that BC Hydro conduct a reasonable long-term pricing scenario for electricity and its substitutes, and provide an update on the associated load forecast.[249] The Executive Director of the Environmental Assessment Office responded by stating that these recommendations were outside of the mandate of the JRP and did not need to be included as conditions to the certificate. The responsible Ministers ultimately gave their approval and issued the certificate without including the recommendations as conditions. They did not give reasons for their decision.[250]

While the Court of Appeal confirmed that it was essential to interpret environmental legislation broadly, the Court held that the recommendations were not "recommendations" within the meaning of sections 17(2)(b) and 17(3)(a) of the *EAA*.[251] The reasoning of the Court was that "recommendations" under section 17 only refer to recommendations to issue

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245 See BC Hydro, News Release, "BC Hydro Issues Request for Proposals for Construction of the Site C Project Transmission Lines" (15 September 2017), online: <https://www.sitecproject.com/bc-hydro-issues-request-for-proposals-for-construction-of-the-site-c-project-transmission-lines>.

246 *Peace Valley Landowner Association v British Columbia (Environment)*, 2016 BCCA 377, 87 BCLR (5th) 44 [*PVLA*].

247 For further information, please refer to Part VIII.B, below.

248 SBC 2002, c 43, s 17(3)(a) [*EAA*]. This section states that, when a matter is referred to a minister, the minister "must consider the assessment report and any recommendations accompanying the assessment report" (*ibid*).

249 Government of Canada, *Report of the Joint Review Panel, Site C Clean Energy Project, BC Hydro* (Ottawa: JRP, 2014) at 280–306, online: <https://www.ceaa-acee.gc.ca/050/documents/p63919/99173E.pdf>.

250 *PVLA*, *supra* note 246 at para 15.

251 *Ibid* at paras 31–32.

a certificate, attach conditions to a certificate, refuse a certificate and, perhaps, to require further assessment. Consequently, any other recommendations of the Panel that do not fall under one of these categories is not a recommendation that must be considered by the Minister. It is interesting to note as well that the Court did hold that these sorts of recommendations were still within the mandate of the JRP to make, even though the ultimate decision did not need to take them into account.[252]

Both the West Moberly and Prophet River First Nations sought leave to appeal the Federal Court of Appeal decision to the Supreme Court of Canada, but on 29 June 2017, the Supreme Court issued a decision declining to hear the two appeals and dismissed the applications with costs.[253] However, Site C has not yet cleared its final legal hurdles. There is currently a challenge underway at the British Columbia Environmental Appeal Board, which has been brought by the West Moberly and Prophet River First Nations as well as a landowner, to appeal the decision by the Deputy Comptroller of Water Rights to issue two water licences to BC Hydro.[254]

VI. UTILITIES AND POWER MARKETS

A. ALBERTA

1. FATE OF ALBERTA'S POWER PURCHASE ARRANGEMENTS

A consistent theme in 2016 for power and utilities was the difficulty in allocating the risk of fluctuating electricity costs while maintaining stable rates for consumers and creating an environment that will attract investment. Litigation in Alberta over the Power Purchase Arrangements (PPAs) provides an example of where the Alberta government took on the risk, and has since been attempting to shift that responsibility by voiding a term of the contract with power purchasers.

PPAs were created by the Alberta government to help facilitate the transition to a competitive, deregulated market for electricity by separating ownership and operation of power plants from the right to sell that power into the power pool. The theory was that power purchasers would bear the risk of changes in the market for electricity in exchange for the opportunity to profit from the sale of energy. Under this arrangement, power generating companies are paid by the buyers as though the system is regulated.

Under the *Electric Utilities Act*,[255] the Balancing Pool is deemed to be the owner of any PPAs which are not sold in auction, as well as of any PPAs which are terminated by a power purchaser. To manage the funding required to carry out both of these tasks, it is also in charge of managing the proceeds of PPA auctions on behalf of electricity consumers and

252 *Ibid* at paras 31–33.
253 See Supreme Court of Canada, News Release, "Judgments in Appeal and Leave Applications" (29 June 2017), online: <https://scc-csc.lexum.com/scc-csc/news/en/item/5565/index.do?r=AAAAAQANcHJvcGhldCByaXZlcgE>.
254 For more information, see *West Moberly First Nations v Deputy Comptroller of Water Rights* (26 October 2016), 2016-WAT-G01, online: EAB <http://www.eab.gov.bc.ca/water/2016wat002a_003a_004a.pdf>.
255 SA 2003, c E-5.1.

allocating surplus or outstanding funds to consumers through credits or charges on electricity bills. The result was that power purchasers would bear typical price fluctuations to the point of unprofitability, which was when they could terminate the PPA and have the Balancing Pool take over, thereby transferring the risk of price volatility to consumers. Three issues have led to a breakdown of this process:

(1) Incremental increases in compliance costs under the *Specified Gas Emitters Regulation*,[256] and as part of the overarching *Climate Leadership Act*;[257]

(2) Continually low electricity rates in Alberta; and

(3) A critical change made to the Change in Law clause in the PPAs which gave power purchasers the option to terminate their PPAs, not just when the PPA became unprofitable for the company due to a change in law made by the government, but also when the PPA became *more unprofitable* due to a change in law.

The Change in Law clause vastly increased the scope of opportunity for a power purchaser to relieve itself of its obligations under a PPA and had the effect of shifting the entire risk of price fluctuation to consumers. Nonetheless, some commentators have argued that the Government of Alberta received a benefit for including such a favourable clause for power purchasers, which was increased bidding prices during the original auction. In fact, the government has collected approximately $3 billion from PPA auctions and it is likely that amount would be less if the terms of the contract were less valuable to power purchasers.[258]

The result was that in 2015, several power purchasers announced their decision to cancel their agreements with the provincial government. Enmax was the first company to do so, and the Balancing Pool accepted the termination. Shortly thereafter, AltaGas and TransCanada also attempted to follow suit, but were told that the Balancing Pool, under the auspices of the AESO, would merely review their request. Subsequently in July 2016, the Alberta government filed a court action to prevent Enmax, TransCanada, AltaGas and Capital Power from terminating their PPAs by means of a declaration that the Change in Law clause was either void for not being included as a term following full public consultation, or was not triggered by the changes to the *Specified Gas Emitters Regulation* on the basis that only the monetary amounts were adjusted and that the substance of the regulation had not been changed at all.[259]

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256 Alta Reg 139/2007.

257 *Supra* note 23.

258 Andrew Leach & Trevor Tombe, "Making Sense of the Legal Fight Over Alberta's Power Agreements," *Maclean's* (9 August 2016), online: <www.macleans.ca/economy/economicanalysis/making-sense-legal-fight-over-alberta-power-agreements>.

259 *Alberta (Attorney General) v Alberta Power (2000) Ltd*, 2017 ABQB 195, 51 Alta LR (6th) 335; *TransCanada Energy Ltd v Balancing Pool*, 2016 ABQB 658, 2016 ABQB 658 (CanLII). See also "Alberta Takes Legal Action Against Power Companies' Secret, 'Enron Clause' to Protect Consumers," *Financial Post* (26 July 2016), online: <business.financialpost.com/commodities/energy/alberta-takes-legal-action-against-power-companies-secret-enron-clause-to-protect-consumers>.

Even though settlements have been reached with Capital Power, AltaGas, and TransCanada, the judgment of the Alberta Court of Queen's Bench remains outstanding.[260] Cases such as *Trillium Power Wind Corporation v. Ontario (Natural Resources)*,[261] and *Churchill Falls (Labrador) Corporation Ltd. v. Hydro-Québec*[262] suggest that the outcome will favour the upholding of the Change in Law provision.[263] The consensus amongst many practitioners following this issue is that the government would be well-advised to either continue to hold PPAs terminated by power purchasers, resell them, or terminate them by paying to the generator an amount equal to the net book value of a generating unit. Although the latter choice could potentially be very expensive for the government, it is worth comparing it against the chilling effect that could settle on investment in Alberta if a critical commercial term is unilaterally voided. Furthermore, as mentioned above, if utility rates stay quite low, consumers may end up faring better by shouldering the costs of termination payouts than when there were no terminations but higher rates. The fact that the government has passed Bill 34, the *Electric Utilities Amendment Act, 2016*[264] (which will empower the Balancing Pool to manage the cost of power companies terminating the PPAs by allowing it to borrow money) seems to suggest that the Alberta government also suspects the terms of the PPAs will be upheld.

2. *KOCH V. ALTALINK MANAGEMENT LTD.*[265]

On 1 December 2016, the Court of Queen's Bench of Alberta overturned the decision of the Surface Rights Board on the issue of the proper interpretation of "injurious affection" or "adverse effect" as it is used in the *Surface Rights Act*.[266] This case involved two parcels of land owned by Barry and Linda Koch, through which the recently constructed Western Alberta Transmission Line ran. When the Kochs purchased their properties in 2013, they were aware of the plans of Altalink Management Ltd. to construct the transmission line, and as a result, they obtained a reduced sale price for the property. When it came time to resolve compensation issues with Altalink, the question arose as to whether the Kochs were entitled to damages for injurious affection, as provided for under section 25(1)(d) of the *Surface Rights Act*.

The majority of the Surface Rights Board decided that the Kochs were not entitled to any compensation under the *Surface Rights Act* on the basis that the issue was really whether the landowners suffered an "economic loss" as a result of not being in the same "position financially" after the construction of the transmission line.[267] In particular, they determined that the transmission line "reduced the land's value, but because the [Kochs] bought the land when they knew the transmission line would be built, their position did not change and the

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260 Discussions of a settlement with Enmax are apparently still ongoing. See James Wood, "Deal Between Alberta Government and Power Companies Over PPA 'Tentative': Notley," *Calgary Herald* (22 November 2016), online: <calgaryherald.com/news/politics/deal-between-alberta-government-and-power-companies-over-ppa-tentative-notley>.

261 2012 ONSC 5619, 70 CELR (3d) 291, rev'd on other grounds 2013 ONCA 683, 117 OR (3d) 721.

262 2016 QCCA 1229, 2016 QCCA 1229 (CanLII) (leave to appeal has been granted).

263 Ron Clark, "Can Governments Rip Up Power Purchase Agreements? Only at a Steep Price" (27 September 2016), online: <www.mondaq.com/canada/x/530286/Utilities/Can+Governments+Rip+Up+Power+Purchase+Agreements+Only+at+a+Steep+Price>.

264 Bill 34, 2nd Sess, 29th Leg, Alberta, 2016.

265 2016 ABQB 678, 3 LCR (2d) 123 [*Koch*].

266 RSA 2000, c S-24.

267 *Koch*, *supra* note 265 at para 40.

construction did not cause them economic loss."[268] On appeal, Justice Sisson did not accept this interpretation of the key issue; the question was simply whether the transmission line would have a negative effect on the remaining land through which the line would run. It was incorrect in law to state that the financial position of the party had to be materially degraded.[269]

B. ONTARIO

1. ONTARIO INTRODUCES FAIR HYDRO PLAN AS PART OF LARGER SYSTEM RESTRUCTURING

On 2 March 2017, the Ontario government introduced the Fair Hydro Plan, which will lower electricity bills by 25 percent for residential consumers, small businesses, and farms, starting in summer 2017. In addition, rate increases over the next four years will be held to the rate of inflation for all consumers. The program is part of a larger system restructuring aimed at addressing long-standing policy challenges and ensuring greater fairness. The reduction in rates will be achieved with the removal of the 8 percent provincial portion of the HST from electricity bills and the refinancing of a portion of the Global Adjustment (GA) charge.[270] The rationale for refinancing the GA is to provide short-term rate relief by spreading the cost of electricity investments over the life cycle of the relevant infrastructure. The government intends to introduce legislation in spring 2017 that would enable Ontario Power Generation and the Independent Electricity System Operator (IESO) to work together to refinance the GA over a longer period of time, as well as outline the role for the Ontario Energy Board (OEB) as it relates to the financing proposal.[271] While the short-term steps for reducing electricity rates for consumers are relatively straightforward, the long-term consequences of these policy changes for market participants are uncertain.

Other aspects of the Fair Hydro Plan that may be of interest to energy practitioners include:

- Expansion of the province's current Rural or Remote Rate Protection (RRRP) Program, which provides a rate subsidy to rural and remote residential consumers who face higher distribution costs compared to urban areas. The expansion of the RRRP Program will increase coverage from 350,000 to approximately 800,000 rural residential customers in the province, providing relief to consumers served by local distribution companies with the highest rates. The cost of the RRRP Program will be funded through tax revenues, shifting it from being funded by ratepayers.

- Expansion of the Ontario Electricity Support Program (OESP), an application-based program which provides a rebate directly on bills for low-income consumers. Ontario

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268 *Ibid* at para 55.
269 *Ibid* at para 163.
270 According to the Ontario Ministry of Energy, the GA funded, in part, Ontario's $50 billion investment in the province's electricity system between 2005 and 2015. See online: Government of Ontario <https://news.ontario.ca/mei/en/2017/05/ontarios-fair-hydro-act-2017.html>.
271 Government of Ontario, "Refinancing the Global Adjustment" (Toronto: Ministry of Energy, 2017) online: <https://news.ontario.ca/mei/en/2017/03/refinancing-the-global-adjustment.html>.

is increasing the OESP by 50 percent and, similar to the RRRP Program, the costs of the OESP will be funded through tax revenues rather than by ratepayers.

According to the Ontario Ministry of Energy, these new measures will cost up to $2.5 billion over the next three years. This amount also includes the provision of a First Nations On-Reserve Delivery Credit and an Affordability Fund to support low-income consumers participating in conservation programs.[272]

Finally, the Ministry of Energy has also released a backgrounder document, entitled *Energy Sector Efficiencies*, which was released as part of the Fair Hydro Plan documents.[273] This document indicates that the OEB will identify opportunities for cost efficiencies by:

- encouraging shared partnerships on services between utilities;
- reviewing business cases supporting OEB regulatory requirements to reduce red tape and eliminate costs that are creating cost pressures for utilities; and
- looking at opportunities to drive further efficiencies for utilities, including the use of innovative technologies and business processes.

Further, the backgrounder notes that the IESO has initiated a market renewal project to enhance efficiency and performance of the wholesale electricity market, which is estimated to save at least $200 million per year starting in 2021.[274]

2. ONTARIO PASSES LEGISLATION FOR LONG-TERM ENERGY PLANNING

In June 2016, the Ontario Legislature passed Bill 135, the *Energy Statute Law Amendment Act, 2016*,[275] which will come into force at a later date which has not yet been announced. Bill 135 introduces certain changes to the *Green Energy Act, 2009*,[276] the *Electricity Act, 1998*[277] and the *Ontario Energy Board Act, 1998*.[278] Bill 135 seeks to expand the role of the Minister of Energy (Minister) in developing long-term energy plans for Ontario. In particular, the Minister will be given responsibility (rather than the IESO) to develop a long-term energy plan at least once each period as specified by regulation. In its supporting role, the IESO will provide technical reports when requested by the Minister. While the Minister will be required to consult with stakeholders, the long-term energy plan will no longer require review by the OEB (as was the case previously). Where required in an implementation plan, the IESO will be empowered to enter into contracts for the procurement of various items (such as electricity storage and transmission systems), some of which are

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272 Government of Ontario, "Enhancing Electricity Support and Conservation Programs" (Toronto: Ministry of Energy, 2017), online: <https://news.ontario.ca/mei/en/2017/03/enhancing-electricity-support-and-conservation-programs.html>.

273 Government of Ontario, "Energy Sector Efficiencies" (Toronto: Ministry of Energy, 2017), online: <https://news.ontario.ca/mei/en/2017/03/energy-sector-efficiencies.html>.

274 *Ibid.*

275 Bill 135, 1st Sess, 41st Leg, Ontario, 2016.

276 *Supra* note 180.

277 SO 1998, c 15, Schedule A.

278 SO 1998, c 15, Schedule B.

beyond the scope of what is currently contemplated in the *Electricity Act, 1998*. Bill 135 also includes amendments to the *Green Energy Act, 2009* to require prescribed persons to report on energy consumption, water use, ratings, or other performance metrics in respect of energy consumption and water use. Stakeholder consultations on the development of a new long-term energy plan are expected at a later date.

VII. PIPELINES

A. FEDERAL

1. *Pipeline Safety Act*

The *Pipeline Safety Act*,[279] which entered into force on 19 June 2016, represents a major development in the regulation of pipelines in Canada. The *PSA* amends both the *National Energy Board Act*[280] and the *Canada Oil and Gas Operations Act*[281] by expanding both the limits of liability for pipeline operators, as well as the mandate of the National Energy Board to have full oversight of the life cycle of a federally regulated pipeline. The changes can be roughly grouped into four main categories: (1) absolute liability; (2) abandonment; (3) financial requirements; and (4) an expanded mandate and the addition of non-use environmental value.

First, the *PSA* adopts an absolute liability approach as part of its effort to reinforce the "polluter pays" principle.[282] Even if the operator took all reasonable precautions to avoid the spill, it will still be held financially responsible. If no fault can be found, any company with the capacity to transport 250,000 barrels of oil per day or more will be obliged to pay a maximum of $1 billion for an unintended release from a pipeline. For companies operating below this threshold, the amount will be established by regulation. Furthermore, there is no longer a limit to the amount that operators have to pay if they are found to be at fault for the unintended release of a pipeline commodity.[283]

Second, operators will now remain responsible for pipelines that they have abandoned. The NEB will enjoy a broadened mandate with regard to enforcing responsibilities associated with abandoned pipelines. Indeed, it may now order pipeline companies to maintain funds dedicated specifically to abandonment activities.[284]

Third, changes instituted by the *PSA* establish the requirement that companies maintain the financial resources necessary to pay the amount that could potentially be applied to them. The NEB may also order any company which accidently releases a pipeline commodity to compensate any government institution for the costs it incurs in dealing with the spill. The proposed Pipeline Financial Requirements Regulation (the Proposed Regulation) will establish classes, absolute liability limits, and financial resource requirements for other

279 SC 2015, c 21 [*PSA*].
280 RSC 1985, c N-7 [*NEBA*].
281 RSC 1985, c O-7.
282 *PSA*, *supra* note 279, s 48.12(4).
283 *Ibid*, s 48.12(5).
284 *Ibid*, s 48.49.

pipeline operators.[285] The classes will be divided into three commodity groupings: oil, gas, and other commodities.[286] According to the Proposed Regulation, companies operating federally regulated pipelines will be subject to the following absolute liability limits.

TABLE 1:
ABSOLUTE LIABILITY LIMITS[287]

Absolute Liability Class	**Details**	**Absolute Liability Limit**
Oil class 1	Companies that are authorized to operate one or more pipelines transporting at least 250 000 barrels of oil per day (bpd). (Established in the *Pipeline Safety Act*.)	$1 billion
Oil class 2	Companies that are authorized to operate one or more pipelines transporting at least 50 000 bpd but fewer than 250 000 bpd of oil.	$300 million
Oil class 3	Companies that are authorized to operate one or more oil pipelines transporting at least 1 bpd but fewer than 50 000 bpd of oil.	$200 million
Gas class 1	Companies that are authorized to operate one or more pipelines that have a risk value of at least 1 000 000.	$200 million
Gas class 2	Companies that are authorized to operate one or more pipelines that have a risk value of at least 15 000 but less than 1 000 000.	$50 million
Gas class 3	Companies that are authorized to operate one or more pipelines that have a risk value of at least 1 but less than 15 000.	$10 million
Other commodities (i.e. other than oil or gas) class 2	Companies that are authorized to operate one or more pipelines carrying other commodities in a liquid state by land or a watercourse or in a semi-solid state across a watercourse.	$10 million
Other commodities (i.e. other than oil or gas) class	Companies that are authorized to operate one or more pipelines carrying other commodities in a gaseous state by land or a watercourse, or in a semi-solid state by land.	$5 million

Some provisions of the Proposed Regulation will be brought into force 10 days after publication in the *Canada Gazette*:

285 Pipeline Financial Requirements Regulations, (2016) C Gaz I, 3059 [PFRR].
286 *Ibid*. For clarity and consistency, "oil" and "gas" have the same definitions as under section 2 of the *NEBA*, *supra* note 280. Other commodities will be defined as those commodities transported by federally regulated pipelines that do not fall within the *NEBA* section 2 definitions of "oil" or "gas," for example: pulp, slurry, salt water, and carbon dioxide.
287 PFRR, *supra* note 285 at 3061–62 [footnotes omitted].

- Section 4(1), which establishes the readily accessible portion of the financial resource requirement (primarily because operators of major oil pipelines will already be subject to absolute liability and have financial resource requirements in accordance with the legislation);[288]

- Sections 5(1) and (2), which provide the parameters for the pooled fund that meet the policy intent of the legislation;[289] and

- Section 3 and subsection 4(2), which provide clarity around acceptable financial instruments the NEB could order a company to use to meet its resource requirements, including the readily accessible portion.[290]

Natural Resources Canada has proposed that the financial resource requirements for other companies (non-major oil pipeline class) come into force 12 months after the Proposed Regulation is published (subsections 2(1) to (5) of the Proposed Regulation). Further, the NEB has been authorized by the Governor in Council to take any action or measure that the NEB considers necessary in relation to an unintended or uncontrolled release of oil, gas, or any other commodity from a pipeline.[291] The Governor in Council will also be empowered to establish a claims tribunal in order to adjudicate compensation claims for damages caused by an unintended release of a pipeline commodity. To administer these functions, the NEB is authorized to withdraw funds from the Consolidated Revenue Fund, and it will also be authorized to recover these amounts from any company operating the pipeline from which the release occurred, as well as from companies operating pipelines transporting a commodity of the same class as the one that was released.

Finally, the *PSA* also introduces the category of environmental "non-use value" for the purpose of calculating damages.[292] While the concept of "non-use value" has been employed before in federal statutes setting out sentencing provisions, it is a relatively rare concept in the realm of civil liability.[293] In determining the full extent of the damages caused by a pipeline release or spill, the addition of "loss of non-use value relating to a public resource" has the potential to greatly expand the scope of environmental damages for polluters.[294]

On the same day that the *PSA* came into force, several new regulations were also enacted, including the *National Energy Board Pipeline Damage Prevention Regulations —*

288 *Ibid* at 3074.
289 *Ibid* at 3074–75.
290 *Ibid* at 3074.
291 *PSA*, *supra* note 279.
292 Parliament's Legislative Summary of Bill C-46 explains the use/non-use designation: "Use values are associated with direct use of the environment such as fishing and swimming in a lake, hiking in a forest — or commercial uses such as logging or farming. Non-use values are related to the knowledge of the continued existence of the environment … or the need to leave environmental resources to future generations" (Government of Canada, *Legislative Summary of Bill C-46: An Act to amend the National Energy Board Act and the Canada Oil and Gas Operations Act* (Ottawa: Library of Parliament, 2015), online: <www.lop.parl.gc.ca/About/Parliament/LegislativeSummaries/bills_ls.asp?Language=E&ls=C46&Mode=1&Parl=41&Ses=2&source=library_prb>).
293 Martin Olszynski, "Environmental Damages Under Bill C-46 (Pipeline Safety Act)" (1 April 2015), *ABlawg* (blog), online: <https://ablawg.ca/2015/04/01/environmental-damages-under-bill-c-46-pipeline-safety-act>.
294 *PSA*, *supra* note 279, s 48.12(1)(c).

Authorizations,[295] the *National Energy Board Pipeline Damage Prevention Regulations — Obligations of Pipeline Companies*,[296] the *Regulations Amending the National Energy Board Onshore Pipeline Regulations*,[297] and the *Regulations Amending the Administrative Monetary Penalties Regulations (National Energy Board)*.[298] The damage prevention regulations are a critical component of the new scheme for managing pipelines, as they acknowledge the problem that some damage caused by a pipeline spill cannot be undone, regardless of an unlimited liability limit for polluters. Some of the changes made by these regulations include the requirement that pipeline companies become members of "one-call centres," and that third parties contact a centre prior to engaging in certain activities near the pipeline. Pipeline companies will also be required to include a damage prevention program within their management systems; these programs must include a public awareness plan, a monitoring system for land use and ownership changes near a pipeline, and an organized method for dealing with activity requests. The regulations also set out a much more involved series of requirements for third parties planning any ground disturbance activities near a pipeline, which extends to the approval of the activities themselves, communication with the affected pipeline company, following the pipeline company's safety measures and instructions, and obtaining permission to move certain equipment across a pipeline.

B. PIPELINE PROJECT UPDATES

1. TRANS MOUNTAIN EXPANSION PROJECT

The proposed Trans Mountain Expansion project involves the addition of a second pipeline to run alongside the current 1,150 kilometre Trans Mountain Pipeline that connects Edmonton, Alberta to Burnaby, British Columbia. The expansion project will add increased capacity of up to 890,000 barrels of crude oil per day. In May 2016, the NEB issued its report on the Trans Mountain Expansion project, recommending that the Governor in Council approve the project. The NEB's report also included 157 recommended conditions, dealing with everything from the integrity of the pipeline to emergency preparedness, spill response, Aboriginal consultation, and socio-economic matters.[299] After conducting a review process involving 400 intervenors, including 73 First Nations organizations, the NEB declared that the project was not likely to cause significant adverse environmental effects, and so should be approved by the Governor in Council.

The Governor in Council issued its approval of the project in November 2016, after ensuring that it complied with the interim principles set out by the Ministers of Environment and Climate Change and Natural Resources for NEB decisions. The federal government's explanatory note, which accompanied its decision, illustrated how its approval aligned with the recent changes made by the *Pipeline Safety Act* and the $1.5 billion investment in the

295 SOR/2016-124.
296 SOR/2016-133.
297 SOR/2016-134.
298 SOR/2016-135.
299 National Energy Board, "Summary of Recommendation — Trans Mountain Expansion Project," online: <https://www.neb-one.gc.ca/pplctnflng/mjrpp/trnsmntnxpnsn/smmrrcmmndtn-eng.html>.

national Oceans Protection Plan regarding ship source spills.[300] Following the British Columbia Supreme Court decision, *Coastal First Nations v. British Columbia (Environment)*,[301] where the Court held that the British Columbia government was not entitled to rely on a federal environmental assessment in order to satisfy its obligations under the British Columbia *EAA*, the province also issued an Environmental Assessment Certificate (EAC) in January 2017.[302] The EAC includes 37 conditions related to Aboriginal consultation, wildlife impact mitigation and monitoring, environmental effect offsetting, and marine spill preparedness. The project proponent expects to have the project operational by 2019.

2. KEYSTONE XL PIPELINE PROJECT

On 24 March 2017, the United States Department of State issued a presidential permit to TransCanada Keystone Pipeline, LP (TransCanada), which will allow TransCanada to construct an international pipeline which is proposed to run from Hardisty, Alberta to the US Gulf Coast refineries. This permit follows on from the executive order signed by President Donald Trump on 24 January 2017, which allowed TransCanada to resubmit its application for the approval of its Keystone XL pipeline. The project received NEB approval in March 2010, but was rejected by the Obama administration in November 2015 following a review by the US State Department. The Presidential memorandum which accompanied the executive order also authorized the State Department to conduct an expedited review of the project, based on the previous work it conducted on the matter including the Environmental Impact Statement issued in 2014.[303] On 26 January 2017, TransCanada submitted an application to the US Department of State for a Presidential Permit for approval of the Keystone XL pipeline,[304] and on 16 February 2017, TransCanada announced that it had filed an application with the Nebraska Public Service Commission seeking approval for the Keystone XL pipeline route through the state.[305] TransCanada will now proceed with applications to obtain the necessary permits and approvals to advance the project to the construction phase. It has also discontinued its claim under chapter 11 of *NAFTA* and will end its US Constitutional challenge.[306]

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300 To Trans Mountain Pipeline ULC for the Trans Mountain Expansion Project: (i) Order — Certificate of Public Convenience and Necessity OC-001-064; (ii) Amending Order in Council AO-002-OC-49; and (iii) Amending Order in Council AO-003-OC-2, (2016) C Gaz 1, 2.

301 2016 BCSC 34, [2016] 2 CNLR 56.

302 *EAA*, *supra* note 248.

303 US, The White House: Office of the Press Secretary, "Presidential Memorandum Regarding Construction of the Keystone XL Pipeline" (Washington, DC: OPS, 2017), online: <https://www.whitehouse.gov/the-press-office/2017/01/24/presidential-memorandum-regarding-construction-keystone-xl-pipeline>.

304 TransCanada, News Release, "TransCanada Applies for Keystone XL Presidential Permit" (26 January 2017), online: <transcanada.mwnewsroom.com/Files/d8/d80ffdd4-cc60-4971-bb01-c22c1b8d4a1c.pdf>.

305 TransCanada, Media Advisory, "TransCanada Applies for Keystone XL Route Approval in Nebraska" (16 February 2017), online: <transcanada.mwnewsroom.com/Files/f0/f073fdd9-4941-4780-bae2-4549967eda1a.pdf>. The proposed route was evaluated by the Nebraska Department of Environmental Quality and approved by the Governor of Nebraska in 2013.

306 TransCanada, News Release, "TransCanada Receives Presidential Permit for Keystone XL" (24 March 2017), online: <https://www.transcanada.com/en/announcements/2017-03-24transcanada-receives-presidential-permit-for-keystone-xl>.

3. NORTHERN GATEWAY PIPELINE PROJECT

The federal government elected not to approve Enbridge's Northern Gateway Pipeline project in November 2016, due to the risk that it posed to First Nations communities and the environment, particularly the Great Bear Rainforest. The $7.9 billion project was initially approved by the previous Conservative government, but that approval was overturned by the Federal Court of Appeal shortly afterwards, due to the failure by the government to adequately consult with affected First Nations.[307]

4. LINE 3 REPLACEMENT PROGRAM PROJECT

Concurrent with its decision to reject the Northern Gateway Pipeline project, the federal government issued its approval for the construction of Enbridge's Line 3 Replacement Program (L3RP) project.[308] The L3RP project involves the replacement of all remaining segments of Enbridge's Line 3 pipeline between Hardisty, Alberta and Superior, Wisconsin, along with construction of associated facilities. The decision to approve the pipeline followed the recommendation of the NEB, which included 89 conditions.[309] There were stronger environmental arguments in favour of this project, particularly because the existing pipeline had been constructed over 40 years ago, raising the risk of spills. The majority of the replacement pipeline is also planned to be constructed in a right of way which parallels or overlaps the existing Enbridge right of way, including the Enbridge Mainline corridor. The NEB determined that Line 3 would result in a safer system, especially when constructed to modern standards. Thirty-seven of the conditions attached to the approval relate to the construction of the replacement pipeline, while the remaining conditions deal with the decommissioning of the existing pipeline and construction of project-related facilities.

5. ENERGY EAST PIPELINE PROJECT

The proposed Energy East pipeline project was a 4,500-kilometre pipeline proposal to carry 1.1 million barrels of crude oil per day from Alberta and Saskatchewan to refineries in eastern Canada and a marine terminal in New Brunswick. The project would have included:

- converting an existing natural gas pipeline to an oil transportation pipeline;
- constructing new pipeline in Alberta, Saskatchewan, Manitoba, Ontario, Quebec and New Brunswick to link up with the converted pipe; and
- constructing the associated facilities, pump stations, and tank terminals required to move crude oil from Alberta to Quebec and New Brunswick, including marine facilities that enable access to other markets by ship.

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307 *Gitxaala Nation v Canada*, 2016 FCA 187, [2016] 4 FCR 418 [*Gitxaala*].

308 Natural Resources Canada, News Release, "Government of Canada Announces Pipeline Plan that will Protect the Environment and Grow the Economy" (29 November 2016), online: <https://www.canada.ca/en/natural-resources-canada/news/2016/11/government-canada-announces-pipeline-plan-that-will-protect-environment-grow-economy.html>.

309 National Energy Board, *NEB Line 3 Replacement Recommendation Report* (Ottawa: NEB, 2016) online: <https://apps.neb-one.gc.ca/REGDOCS/Item/View/2949686>.

On 5 October 2017, the project proponent (TransCanada Corporation) announced that after a careful review of changed circumstances, it will no longer be proceeding with the Energy East pipeline (and Eastern Mainline) project.[310]

VIII. ABORIGINAL

A. POLICY UPDATE

1. FEDERAL GOVERNMENT LOOKS TO IMPLEMENT UN *DECLARATION ON THE RIGHTS OF INDIGENOUS PEOPLES*

In May 2016, the federal government announced its unqualified support for the *United Nations Declaration on the Rights of Indigenous Peoples*.[311] Initially, Canada had voted against the declaration in 2007, but subsequently issued a statement of qualified support in 2010.[312] Canada's earlier reluctance to adopt *UNDRIP* was driven by concerns with the provisions stipulating that states must obtain the "free, prior and informed consent" (FPIC) of Aboriginal groups in certain situations.[313] In particular, there was concern that these provisions could be interpreted as providing Aboriginal groups with a veto on government actions or decisions affecting an Aboriginal group's traditional territory, including decisions relating to resource development projects. While the federal government is still in the process of determining how *UNDRIP* will be implemented, the federal government has indicated that Canada will not be adopting *UNDRIP* word for word into Canadian law.[314] Also, it plans to carry out consultations on how *UNDRIP* can be interpreted and implemented within Canada's existing constitutional framework. It is unlikely that Canada will interpret FPIC as a veto, given that the Minister of Indigenous and Northern Affairs, Carolyn Bennett, stated in May 2016 that section 35 of the *Constitution Act, 1982*[315] represents the "full box of rights for Indigenous peoples in Canada" and that "our constitutional obligations serve to fulfil all of the principles of the declaration, including 'free, prior, and informed consent.'"[316] These qualifications necessarily limit the scope of FPIC because an interpretation of FPIC as a veto would run contrary to the *Constitution Act, 1982*. Canada's decision to implement *UNDRIP* will only apply to federal decision-making; at the provincial level, only Alberta has indicated that it will implement *UNDRIP* and Cabinet ministers have been tasked with currently

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310 See TransCanada, News Release, "TransCanada Announces Termination of Energy East Pipeline and Eastern Mainline Projects" (5 October 2017), online: <https://www.transcanada.com/en/announcements/2017-10-05-transcanada-anounces-termination-of-energy-east-pipeline-and-eastern-mainline-projects/>.

311 GA Res 61/295, UNGAOR, 61st Sess, Supp No 49, UN Doc A/Res/61/295 (2007), online: <www.un.org/esa/socdev/unpfii/documents/DRIPS_en.pdf> [*UNDRIP*].

312 "Canada Endorses Indigenous Rights Declaration," *CBC News* (12 November 2010), online: <www.cbc.ca/news/canada/canada-endorses-indigenous-rights-declaration-1.964779>.

313 *UNDRIP*, *supra* note 311, art 10.

314 Laura Kane, "Jody Wilson-Raybould Lays Out Vision for UN Indigenous Rights Declaration," *Canadian Press* (7 September 2016), online: <www.cbc.ca/news/canada/british-columbia/jody-wilson-raybould-lays-out-vision-for-un-indigenous-rights-declaration-1.3752129>.

315 Being Schedule B to the *Canada Act 1982* (UK), 1982, c 11.

316 See "Fully Adopting UNDRIP: Minister Bennett's Speech at the United Nations," *Northern Public Affairs* (11 May 2016), online: <www.northernpublicaffairs.ca/index/fully-adopting-undrip-minister-bennetts-speech>. See also Indigenous and Northern Affairs Canada, "Speech for the Honourable Carolyn Bennett, Minister of Indigenous and Northern Affairs at the United Nations Permanent Forum on Indigenous Issues 16th Session" (25 April 2017), online: <https://www.canada.ca/en/indigenous-northern-affairs/news/2017/05/speaking_notes_forthehonourablecarolynbennettministerofindigenou.html>.

reviewing how the principles of *UNDRIP* may be implemented in accordance with Alberta law and the *Constitution Act, 1982*.[317]

B. LITIGATION UPDATE

1. BRITISH COLUMBIA AND FEDERAL APPELLATE COURTS DISMISS FIRST NATIONS' CHALLENGE TO SITE C

In two separate decisions in early 2017, the Federal Court of Appeal and British Columbia Court of Appeal dismissed court challenges by the Prophet River First Nation and the West Moberly First Nation (the First Nations) of the federal and provincial environmental assessment (EA) approvals for the Site C hydro power project in British Columbia, a third dam and hydroelectric generation facility on the Peace River that is currently under construction. Site C underwent a Joint Review Panel (JRP) hearing that combined federal and provincial environmental reviews. The JRP determined that Aboriginal consultation for the project had been carried out in good faith and that the process had been reasonable and appropriate in the circumstances. Site C was approved by the federal Governor in Council (GIC), who acknowledged that while the project would have an adverse effect on traditional First Nation activities, it was justified pursuant to section 52(4) of the *CEAA, 2012*.[318] Following the issuance of the Order in Council, Site C received its provincial environmental assessment certificate, which set out 77 conditions aimed at addressing First Nation concerns and other project impacts.

The two appellate courts separately upheld earlier decisions of the Federal Court and the British Columbia Supreme Court, which had dismissed applications for judicial review by the First Nations of the provincial and federal EA approvals for Site C.[319] The First Nations, both signatories of Treaty 8, had argued that the approvals infringed their treaty rights and that there was inadequate consultation and accommodation. The Federal Court of Appeal delivered its decision[320] on 23 January 2017, which considered: (1) whether the GIC has jurisdiction under section 52(4) of *CEAA, 2012* to decide whether the project would constitute an infringement of the First Nations' treaty rights; (2) whether the First Nations had a legitimate expectation that the issue of infringement would be addressed by the GIC; (3) whether the Crown's duty to consult and accommodate the First Nations was met; and (4) the reasonableness of the GIC's decision. In the earlier decision, the Federal Court emphasized that the GIC makes decisions based on polycentric considerations and a balancing of individual and public interests, which includes Aboriginal interests and concerns. This means that decisions of the GIC are afforded considerable deference and the GIC is entitled to privilege. In addition, the Federal Court held that the Crown did not need to make a determination on the First Nations' infringement claim. The Federal Court of Appeal unanimously upheld the Federal Court's decision. While the First Nations did not appeal the Federal Court's determination that the Crown had not breached its duty to consult and accommodate, the Federal Court of Appeal did note that the First Nations had not

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317 Letter from Rachel Notley to cabinet ministers (7 July 2015), online: <indigenous.alberta.ca/documents/Premier-Notley-Letter-Cabinet-Ministers.pdf>.

318 *Supra* note 67.

319 *Prophet River First Nation v Canada (AG)*, 2015 FC 1030, 97 CELR (3d) 23.

320 *Prophet River First Nation v Canada (AG)*, 2017 FCA 15, 408 DLR (4th) 165.

fulfilled their reciprocal obligations during the consultation process because they had not provided adequate information to the JRP to support their claims.[321]

Unlike the appeal in the Federal Court of Appeal, the First Nations appealed the findings of the British Columbia Supreme Court[322] on both the infringement and duty to consult aspects of the case. In the British Columbia Court of Appeal decision released on 2 February 2017, Justice Lowry acknowledged that the Court was in the "unusual, if not awkward, position" of having to consider the discharge of the Crown's duty to consult and accommodate in the face of a final order of another Canadian Court establishing there was no breach of that duty.[323] The British Columbia Court of Appeal held that (1) on the issue of infringement, the Ministers were not required to determine whether the project constituted an unjustifiable treaty infringement before issuing the EA certificate; and (2) on the issue of consultation, the consultation process was adequate and the Ministers were not required to make a determination on the adequacy of consultation and accommodation before exercising their statutory discretion.[324] The First Nations sought leave to appeal both the Federal Court of Appeal and British Columbia Court of Appeal decisions to the Supreme Court of Canada, however as noted above, the Supreme Court of Canada dismissed the applications with costs on 29 June 2017.

2. *FORT NELSON FIRST NATION V. BRITISH COLUMBIA (ENVIRONMENTAL ASSESSMENT OFFICE)*

Although this case involves the proposed development of a frac sand operation in northeastern British Columbia, the decision of the British Columbia Court of Appeal in *Fort Nelson First Nation v. British Columbia (Environmental Assessment Office)*[325] will be of interest to energy practitioners. In a decision delivered on 19 December 2016, the British Columbia Court of Appeal allowed the appeal by the project proponent and British Columbia Environmental Assessment Office (BC EAO) of an earlier Supreme Court of British Columbia decision.[326] In assessing[327] whether the project met the sand and gravel mine threshold to trigger an environmental assessment under the provincial *Environmental Assessment Act*,[328] the project proponent interpreted the term "production capacity" to mean sand and gravel excavated for sale or use, and BC EAO subsequently confirmed this interpretation of the threshold. Under this interpretation, the project was not automatically reviewable. The Fort Nelson First Nation (FNFN) brought a judicial review of the BC EAO's interpretation of the sand and gravel threshold, alleging that the BC EAO's interpretation was unreasonable and that BC EAO had breached its duty to consult with FNFN. FNFN asserted that all sand or gravel excavated on a site (including waste volumes) must be included in

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321 *Ibid.*
322 *Prophet River First Nation v. British Columbia (Environment)*, 2015 BCSC 1682, [2016] 1 CNLR 207.
323 *Prophet River First Nation v. British Columbia (Environment)*, 2017 BCCA 58, 408 DLR (4th) 201 at para 18.
324 *Ibid.*
325 2016 BCCA 500, [2017] 4 WWR 422 [*FNFN* BCCA].
326 *Fort Nelson First Nation v British Columbia (Environmental Assessment Office)*, 2015 BCSC 1180, 96 CELR (3d) 85.
327 Prior to a statutory authorization being issued, it is the responsibility of the proponent to determine whether a project is reviewable. The British Columbia Court of Appeal held that EAO's expression of an opinion on the interpretation of the threshold did not constitute Crown conduct for the purposes of the duty to consult, and it did not have an adverse effect on FNFN's rights.
328 *Supra* note 248.

determining "production capacity." The Supreme Court of British Columbia agreed with the FNFN's interpretation of the threshold, meaning that BC EAO had not discharged its duty to consult FNFN. The project proponent and BC EAO appealed the Supreme Court of British Columbia decision, which was allowed by the British Columbia Court of Appeal. The British Columbia Court of Appeal held that the interpretation of the threshold by the BC EAO is a non-binding opinion, which was not a decision amenable to judicial review because it did not constitute the type of "strategic high level" decision that the Supreme Court of Canada stated in *Rio Tinto* might attract a duty to consult, as determined by the chambers judge.[329] In any case, the British Columbia Court of Appeal went on to consider the merits of the judicial review and concluded that the BC EAO's interpretation was reasonable. In particular, the plain meaning of the threshold supports the BC EAO's decision and as a result, no duty to consult was owed to FNFN. Even if the interpretation of the threshold did attract a duty to consult, such duty was met through correspondence between the BC EAO and FNFN.

3. *MÉTIS NATION OF ALBERTA ASSOCIATION FORT MCMURRAY LOCAL COUNCIL 1935 V. ALBERTA; FORT CHIPEWYAN MÉTIS NATION OF ALBERTA LOCAL #125 V. ALBERTA*

In *Métis Nation of Alberta Association Fort McMurray Local Council 1935 v. Alberta*,[330] the Aboriginal Consultation Office (ACO) determined that a duty to consult the Métis Nation of Alberta Association Fort McMurray Local Council[331] (FM Local) was not triggered in connection with several energy resource development applications. In response to certain Notices of Resource Applications that FM Local had received in late fall 2013, FM Local sent Statements of Concern (SOC) to the AER and the ACO. Subsequently, FM Local received detailed information requests from ACO which it was required to answer within a few weeks. FM Local requested an extension of time to provide further information, which request was denied by the ACO with respect to three of the four projects. Although the ACO had not reviewed all of the information that FM Local provided, it determined that the Crown's duty to consult had not been triggered. The issues at hand were whether FM Local had provided sufficient information to trigger the duty to consult, and ACO's procedural fairness in requiring and assessing the information. In its decision, the Alberta Court of Queen's Bench found that Alberta has an internal directive which prescribes the process for determining whether consultation is required when a Metis community asserts an Aboriginal right. In this case, the Court determined that decisions of this nature "require a full and fair consideration of the issues, and the claimant and others whose important interests are affected by the decision in a fundamental way must have a meaningful opportunity to present the various types of evidence relevant to their case and have it fully and fairly considered."[332] The Court also found that the ACO breached the principles of procedural fairness and in particular, that the deadlines imposed by the ACO were "extremely short, inflexible and appeared to be arbitrarily imposed."[333] Further, the Court said that the ACO violated principles of procedural fairness by failing to meet its duty in providing clear deadlines

329 *FNFN* BCCA, *supra* note 325 at paras 118–25, citing *Rio Tinto Alcan Inc v Carrier Sekani Tribal Council*, 2010 SCC 43, [2010] 2 SCR 650.
330 2016 ABQB 712, 7 CELR (4th) 116 [*FM Local*].
331 Also known as Fort McMurray Métis Local 1935.
332 *FM Local*, *supra* note 330 at para 178, citing *Baker v Canada (Minister of Citizenship and Immigration)*, [1999] 2 SCR 817 at para 32.
333 *FM Local*, *ibid* at para 196.

within its process, and failing to demonstrate that it fully and fairly considered the information and evidence submitted to it by FM Local.[334] The Court quashed two of the ACO's decision letters, and the question of whether the duty to consult FM Local was triggered was sent back to the ACO for reconsideration.

This judicial review was heard together with the judicial review in *Fort Chipewyan Métis Nation of Alberta Local #125 v. Alberta*, however the Court came to a different conclusion based on the facts.[335] In *FCM Local*, the ACO determined that a duty to consult on an oil sands project had not been triggered because the Fort Chipewyan Nation of Alberta Local 125 (FCM Local) provided insufficient information regarding who it represented for the purposes of asserting Aboriginal rights, its authority to act, the scope and nature of the rights asserted, and any potential adverse impacts of the project upon the group's asserted rights. FCM Local argued that it had provided sufficient information to trigger the duty to consult and that the ACO's decision was unreasonable and incorrect. The Court had to determine whether the ACO had breached its duty of procedural fairness and whether the duty to consult had been triggered. On the issue of procedural fairness, the Court found that there was no breach of procedural fairness by the ACO. With respect to the sufficiency of information, the Court found that the information provided by FCM Local did not support a claim to site-specific Aboriginal rights and overall, FCM Local was unable to establish that membership in the FCM Local is determinable by the three *Powley* factors of ancestral connection, self-identification, and community acceptance.[336] In finding that the evidence provided by FCM Local fell short of demonstrating how the project would adversely impact the group's Aboriginal rights, the Court held that the ACO's decision that the duty to consult was not triggered amounted to an acceptable and defensible decision based on the facts and the applicable law. As a result, the Court dismissed FCM Local's judicial review application. These cases demonstrate that the ACO will be held to a high standard of procedural fairness when dealing with potentially affected Metis communities. Also in Alberta, assertions of Aboriginal rights must be supported by sufficient evidence in order to trigger the Crown's duty to consult.

4. *MICHIPICOTEN FIRST NATION V. MINISTER OF NATURAL RESOURCES AND FORESTS*

The Michipicoten First Nation (MFN) brought an application for judicial review in connection with provincial approvals for the Bow Lake wind farm project, a 36 turbine facility on the eastern shore of Lake Superior. The MFN had sought to quash the approvals on the basis that the Crown breached its duty to consult. In its 2 November 2016 decision, the Ontario Superior Court of Justice (Divisional Court) dismissed the MFN's application for undue delay (which had been brought 15 months after the project's *Renewable Energy Act* approval).[337] The Court also dismissed the MFN's allegation that it had not been adequately consulted prior to the approvals being issued. The Court determined that the duty to consult was on the low end of the spectrum because: (1) there was no evidence that the

334 *Ibid* at para 215.
335 2016 ABQB 713, 7 CELR (4th) 171 [*FCM Local*].
336 *Ibid* at paras 354, 359, citing *R v Powley*, 2003 SCC 43, [2003] 2 SCR 207.
337 *Michipicoten First Nation v Minister of Natural Resources and Forests*, 2016 ONSC 6899, 7 CELR (4th) 59.

MFN exercised Aboriginal or treaty rights over the project lands; (2) only a small portion of the project land is within MFN traditional territory; and (3) the land had been previously used for commercial, industrial, and recreational use.[338] Based on the consultation record, the Court concluded that the MFN had been properly consulted and numerous opportunities had been made available for MFN to provide input. The Court also held that the MFN did not provide meaningful feedback on the project despite the opportunities to do so.

5. *PETER BALLANTYNE CREE NATION v. CANADA (ATTORNEY GENERAL)*

The Peter Ballantyne Cree Nation (PBCN) commenced an action against the respondents for flooding of Indian Reserve 200 (Southend Reserve), which PBCN claimed was caused by the construction of hydroelectric facilities on the Reindeer River. In particular, PBCN sought damages and declaratory relief for breach of the honour of the Crown, breach of fiduciary duty, and trespass (including continuing trespass) in connection with the continuous flooding of a portion of the Southend Reserve that PBCN alleged was caused by the construction and operation of the Whitesand Dam, which began operating in 1943. The respondents applied for summary judgment and succeeded primarily on the basis that the claims were statute barred. As a result, all claims were dismissed against the respondents; PBCN appealed the decision of the chambers judge on the basis that the actions revealed a genuine issue for trial and should not have been subject to summary dismissal. On 28 September 2016, the Saskatchewan Court of Appeal dismissed, in part, the appeal of a summary dismissal of PBCN's claim.[339] The Court of Appeal agreed with the determination of the Chambers judge that the bulk of PBCN's claims were out of time, but held that PBCN's claim against Saskatchewan and SaskPower for continuing trespass on their reserve land should proceed to trial. The Court also dismissed PBCN's claim for a breach of the duty to consult for every decision to change the amount of water passing through the Whitesand Dam, which PBCN had argued was a novel adverse impact. In finding that there was currently no novel impact that triggered the duty to consult, the Court noted that the same area of the reserve has been flooded since the creation of the dam in 1943 and that the changes in the amount of water passing through the dam were made in accordance with the terms of the dam's operating licence.[340]

6. *GITXAALA NATION v. CANADA*

In June 2014, the federal government approved the Northern Gateway Pipeline project, which consists of two 1,178 kilometer pipelines and related infrastructure. The proposed project would transport oil by pipeline from Bruderheim, Alberta to Kitimat, British Columbia, where the oil would be loaded onto tankers for transport to export markets; the second proposed pipeline would carry condensate from the tankers for distribution in Alberta. A framework for consultation with Aboriginal groups was established, which set out five phases for consultation throughout the regulatory review process. In 2006, the project was referred by the federal Minister of Environment to a Joint Review Panel (JRP) to

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338 *Ibid* at para 84.
339 *Peter Ballantyne Cree Nation v Canada (Attorney General)*, 2016 SKCA 124, [2017] 1 WWR 685.
340 *Ibid*.

conduct an environmental assessment and prepare a report for the Governor in Council. The JRP's report was released in December 2013 and found that the project was in the public interest. The JRP recommended that the project be allowed to move forward with regulatory approvals, subject to 209 conditions.

While the project is supported by 31 Aboriginal equity partners, eight First Nations (Gitxaala Nation, Haisla Nation, Gitga'at First Nation, Kitasoo Xai'Xais, Heiltsuk Tribal Council, Nadleh Whut'en, Nak'azdli Whut'en, and Haida Nation) challenged the Governor in Council's approval of the project by bringing nine applications for judicial review seeking to overturn the decision.[341] In particular, these eight First Nations took issue with the fourth consultation phase, which occurred following the release of the JRP's report, but prior to the Governor in Council's decision. On 23 June 2016, the Federal Court of Appeal held that the federal government failed to fulfil the Crown's duty to consult in the fourth phase, and remitted the matter to the Governor in Council for re-determination.[342] Before making its decision, the Governor in Council must fulfil its duty to consult affected Aboriginal communities. While the Federal Court of Appeal approved of the federal government's consultation framework and cited many ways in which Canada acted reasonably, the Federal Court of Appeal noted errors such as insufficient timelines and a lack of meaningful dialogue. The Federal Court of Appeal did not take any issue with the consultation undertaken by the project proponent, rather the Court focused on the conduct of the Crown. The Federal Court of Appeal acknowledged that the challenges associated with the approval process for Northern Gateway were immense and that the Crown should not be held to a standard of perfection in discharging its duty to consult.[343] Nonetheless, the Court found that an important phase of the Aboriginal consultation process "fell well short of the mark."[344]

341 According to the project proponent, online: <www.gatewayfacts.ca/Aboriginal-Ownership/Ownership.aspx>.
342 *Gitxaala*, *supra* note 307.
343 *Ibid* at para 19.
344 *Ibid* at para 8.

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