RECENT LEGISLATIVE AND REGULATORY DEVELOPMENTS OF INTEREST TO ENERGY PRACTITIONERS

DUFFERIN HARPER, TERRI-LEE OLENIUK,
LARS OLTHAFER, AND KATIE SLIPP*

This article provides a high-level overview of regulatory and legislative developments in Canada between May 2018 and early May 2019. The authors reviewed regulatory initiatives, decisions, case law, and legislation from provincial, territorial, and federal authorities. Topics of note include climate change regulation, renewable energy initiatives, federal project approvals and pipeline issues, abandonment liability, and developments related to Indigenous law.

TABLE OF CONTENTS

I. INTRODUCTION . . . 562
II. CLIMATE CHANGE . . . 562
A. THE *GGPPA* . . . 563
B. *GGPPA* REFERENCE(S) . . . 564
C. ALBERTA'S NEW METHANE RULES . . . 566
III. ELECTRICITY . . . 567
A. POWER MARKETS . . . 567
B. RENEWABLES . . . 570
IV. OFFSHORE . . . 572
A. NOVA SCOTIA ABANDONMENT . . . 572
B. M&NP TOLL SETTLEMENT . . . 573
C. M&NP ABANDONMENT FUNDING . . . 574
V. OIL AND GAS . . . 575
A. PROVINCIAL RAILCARS LEASE . . . 575
B. NEB REPORT ON OIL PIPELINE AND RAIL OPTIMIZATION . . . 576
C. REPORT ON HYDRAULIC FRACTURING IN BRITISH COLUMBIA . . . 577
D. ENBRIDGE MAINLINE APPORTIONMENT . . . 577
E. THE CRESCENT POINT COMPLAINT . . . 579
F. BRITISH COLUMBIA NOISE CONTROL BEST PRACTICES GUIDELINE . . . 580
VI. SIGNIFICANT REGULATORY DECISIONS . . . 581
A. THE FEDERAL COURT OF APPEAL TMEP DECISION . . . 581
B. COASTAL GASLINK JURISDICTIONAL DISPUTE . . . 583
C. NIPIGON LNG CORPORATION . . . 584
D. *EMERA BRUNSWICK V. SIERRA SUPPLIES LTD.* . . . 585
E. *FORT MCKAY FIRST NATION V. PROSPER PETROLEUM LTD.* . . . 585

* Dufferin Harper, Terri-Lee Oleniuk, Lars Olthafer, and Katie Slipp are partners at Blake, Cassels & Graydon LLP. They would like to thank Melia Stewart and Bharbara Parken who are students-at-law with Blake, Cassels & Graydon LLP for their significant contributions to this article.

F. NEB DECISION MH-031-2017, NOVA GAS TRANSMISSION LTD. – NORTH MONTNEY MAINLINE VARIANCE AND SUNSET CLAUSE EXTENSION APPLICATION 586
G. PROVOST RELIABILITY UPGRADE PROJECT 587
H. *REFERENCE RE ENVIRONMENTAL MANAGEMENT ACT (BRITISH COLUMBIA)* 587
VII. LEGISLATIVE DEVELOPMENTS 587
A. PROTECTIVE LEGISLATION 587
B. OIL PRODUCTION CURTAILMENT 588
C. UPDATE ON PROPOSED FEDERAL LEGISLATION 589
D. CHANGES TO BRITISH COLUMBIA'S ENVIRONMENTAL ASSESSMENT PROCESS 590
E. REGULATORY IMPLICATIONS OF REDWATER 591
F. *UNDRIP* AND BILL C-262 592
VIII. ENVIRONMENTAL 592
A. *SPECIES AT RISK ACT* 592

I. INTRODUCTION

Yet another year has passed, bringing many important developments for the practice of energy and regulatory law in Canada. As competing interests vie for recognition by governments, regulatory bodies, and domestic and international audiences, energy development grows increasingly controversial. The Trans Mountain Expansion Project's quashed approval and subsequent reconsideration, Bill C-69's Canadian Senate Committee tour, and the imposition of a federal carbon price have all motivated strong support and opposition nationwide. Perhaps more than ever before, Canadians are becoming involved and interested in the future of energy regulation in Canada. These decisions and more are all part of the legacy of 2018–2019, and the coming year promises to be no less eventful.

This article provides a high-level overview of these and other significant regulatory and legislative developments of interest to energy lawyers, which have taken place over the review period from April 2018 to early May 2019.

II. CLIMATE CHANGE

The landscape of climate change regulation has changed rapidly over the past year. In October 2018, the Intergovernmental Panel on Climate Change released its special report on the impacts of global warming.[1] That report warned of the serious risks related to rising atmospheric temperatures. Meanwhile, President Trump has committed to withdrawing the United States from the Paris Agreement in 2021 and has rolled back significant new climate change regulations under the *Clean Air Act*.[2] In Canada, the provinces are divided over their

1 Intergovernmental Panel on Climate Change, "Global Warming of 1.5°C" (Geneva: IPCC, 2018), online: <www.ipcc.ch/sr15/>.

2 Kevin Liptak & Jim Acosta, "Trump on Paris Accord: 'We're Getting Out,'" *CNN* (2 June 2017), online: <cnn.com/2017/06/01/politics/trump-paris-climate-decision/index.html>; *Clean Air Act*, 42 USC §7401 (1963).

approaches to the issue, while the federal government has implemented national carbon pricing under the *Greenhouse Gas Pollution Pricing Act*.[3]

A. THE *GGPPA*

Part I of the *GGPPA* is an "at the pump" charge on fossil fuels.[4] Part II is a large industrial emitters regime.[5]

The *GGPPA* is intended to work as backstop legislation and only apply in those provinces that had not, by 1 April 2019, already imposed their own, equal or more stringent carbon pricing (although it remains vague about what would be acceptable).[6] The federal backstop is currently priced at $20 per tonne of carbon dioxide equivalent (CO_2e) emitted based on the type of fuel purchased (increasing by $10 per year until 2022, or to $50 per tonne).[7] The *GGPPA* also has an emissions limit of 80 or 90 percent of the industrial average for large industrial emitters (LIE).[8] LIE are required to emit less than the regulated average, or pay for any emissions above that level.[9] Draft regulations that further refine the pricing system were recently published.[10]

As part of the federal government's support for the Trans Mountain Expansion Pipeline (TMEP),[11] former Alberta Premier Rachel Notley agreed to support the Pan-Canadian Framework[12] (the precursor to the *GGPPA*).[13] She subsequently withdrew Alberta's support[14] on the same day the Federal Court overturned the TMEP approval.[15]

As of April 2019, both Part I and Part II of the *GGPPA* apply in Saskatchewan, Manitoba, New Brunswick, and Ontario.[16] Part II of the *GGPPA* applies in Yukon, Nunavut, and Prince

---

3 SC 2018, c 12, s 186 [*GGPPA*].

4 *Ibid*, s 17(1).

5 *Ibid*, Part 2, Division 1.

6 Under the *GGPPA*, the Governor in Council has significant discretion over whether a province is included in Schedule 1 (provinces subject to the federal backstop) or not. See for example sections 166(2) and 168(2)(c) of the *GGPPA*.

7 *GGPPA*, *supra* note 3, Schedule 4.

8 Government of Canada, "Update on the Output-Based Pricing System: Technical Backgrounder," online: <canada.ca/en/services/environment/weather/climatechange/climate-action/pricing-carbon-pollution/output-based-pricing-system-technical-backgrounder.html>. Large industrial emitters are those that emit 50 kt or more of CO_2e.

9 *GGPPA, supra* note 3, s 174(1); *Notice Establishing Criteria Respecting Facilities and Persons and Publishing Measures*, SOR/2018-213.

10 Canada, Department of Finance, "Backgrounder: Proposed Refinements to the Federal Carbon Pollution Pricing System," online: <fin.gc.ca/n19/data/19-023_1-eng.asp>.

11 The TMEP would expand the capacity of the existing Trans Mountain Pipeline from 300,000 billion barrels per day (bbpd) to 890,000 bbpd. It connects Strathcona County, Alberta, to Burnaby, British Columbia, and the Westridge Marine Terminal. See National Energy Regulator, "Project Background & the Hearing Process," online: <cer-rec.gc.ca/pplctnflng/mjrpp/trnsmntnxpnsn/hrngprcss-eng.html>.

12 Environment and Climate Change Canada, "Pan-Canadian Framework on Clean Growth and Climate Change: Canada's Plan to Address Climate Change and Grow the Economy" (Gatineau: ECCC, 2016), online: <publications.gc.ca/collections/collection_2017/eccc/En4-294-2016-eng.pdf> [Pan-Canadian Framework].

13 Michelle Bellefontaine, "Notley's Leadership, Climate Plan, A Factor in Pipeline Approvals, PM Says," *CBC News* (29 November 2016), online: <cbc.ca/news/canada/edmonton/premier-leadership-climate-plan-factor-pipeline-approvals-1.3873664>.

14 John Paul Tasker, "After Federal Court Quashes Trans Mountain, Rachel Notley Pulls Out of National Climate Plan," *CBC News* (30 August 2018), online: <cbc.ca/news/politics/trans-mountain-federal-court-appeals-1.4804495>.

15 *Tsleil-Waututh Nation v Canada (AG)*, 2018 FCA 153 [*Tsleil-Waututh*].

16 *Supra* note 3, Schedule 1. Part 2 of the *GGPPA* applied as of 1 January 2019.

Edward Island.[17] Alberta, British Columbia, Quebec, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories have all implemented local regimes sufficiently stringent to avoid the federal regime (at least for now).[18]

Revenues from the *GGPPA* carbon pricing system are to be returned to the province or territory of origin.[19] In Saskatchewan, Manitoba, New Brunswick, and Ontario, the majority of the revenues generated by the federal carbon tax on fuel are expected to be returned to individuals via an annual carbon rebate, called Climate Action Incentive payments.[20] The amount of this rebate will vary by household size and by province, in order to account for differences in provincial energy supply mixes (and correspondingly disproportionate burdens of the tax).[21] The remainder of the revenues will be used to support organizations that cannot pass the cost of the fuel charge onto consumers, such as small businesses, schools, municipalities, non-profits, and Indigenous communities. Proceeds under the output-based pricing system will generally be directed to reducing greenhouse gas emissions in the relevant province.[22]

B. *GGPPA* REFERENCE(S)

Saskatchewan,[23] Ontario,[24] and Manitoba[25] have each filed constitutional reference questions before the courts asking whether the *GGPPA* is ultra vires federal authority. In Alberta, newly elected Premier Jason Kenney promises to remove the provincial carbon tax and to have Alberta file its own *GGPPA* reference.[26]

1. THE SASKATCHEWAN REFERENCE QUESTION

Saskatchewan asserted the Canadian Constitution precludes regulation that discriminates between provinces on the basis of their regulatory choices. It argued that the *GGPPA* violates the principles of federalism, including sovereign authority of the provinces within their jurisdiction; that the carbon price is a tax and not a regulatory charge; and that it constitutes taxation without representation, contrary to section 53 of the *Constitution Act, 1867*.[27] The Attorney General of Saskatchewan did *not* argue that the federal government cannot impose a carbon tax, only that the federal government cannot impose it disproportionately.[28]

---

17 *Ibid*, Schedule 1, Part 2.

18 *Order Amending Part 2 of Schedule 1 to the* Greenhouse Gas Pollution Pricing Act, PC 2018-1292, (2018) C Gaz II, 3760, s 2.

19 *Ibid*, s 1.

20 Government of Canada, "Pricing Pollution: How It Will Work," online: <canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work.html> (see Saskatchewan, Manitoba, New Brunswick, and Ontario links).

21 *Ibid*.

22 *Ibid*.

23 *Reference re Greenhouse Gas Pollution Pricing Act*, 2019 SKCA 40 [*Re GGPPA* (SK)].

24 *Reference re Greenhouse Gas Pollution Pricing Act*, 2019 ONCA 544 [*Re GGPPA* (ON)]. Note: For all filings related to the Ontario reference question, see online: <www.ontariocourts.ca/coa/ggppa/>.

25 *R v Governor in Council*, (24 April 2019), Winnipeg, FCT-685-19 (application for judicial review) [Manitoba Application].

26 United Conservative Party, "Platform: Getting Alberta Back to Work," online: <albertastrongand free.ca/policy/> [UCP Platform].

27 *Constitution Act, 1867* (UK), 30 & 31 Vict, c 3, s 53, reprinted in RSC 1985, Appendix II, No 5.

28 *Re GGPPA* (SK), *supra* note 23 at para 8.

The federal government argued the backstop falls under Parliament's authority over matters of national concern pursuant to peace, order, and good government.[29] It asserted the national concern was GHG emissions or, more particularly, the "cumulative dimensions of GHG emissions."[30] It also asserted the *GGPPA* imposed a regulatory charge and not a tax.

A 3-2 majority of the Saskatchewan Court of Appeal held the *GGPPA* falls within the legislative authority of Parliament and is not unconstitutional in whole or in part.[31] However, it did so on the narrow basis that the matter of national concern was the "establishment of minimum nationals standards of price stringency for GHG emissions," rather than the broader concept of "GHG emissions."[32]

2. THE ONTARIO REFERENCE QUESTION

The Conservative provincial government cancelled Ontario's cap-and-trade program in the spring of 2018.[33] In August, it announced its own *GGPPA* reference question.[34]

Ontario argues that by purporting to govern all GHG-producing activities in Canada, the *GGPPA* cannot be supported under any head of federal power. It also argues the *GGPPA* violates section 53 of the *Constitution Act, 1867*,[35] in that there is an insufficient nexus between the revenues raised by the Act and its regulatory purpose. More specifically, the *GGPPA* does not require the proposed tax credits to individuals be spent on actions that would mitigate climate change.[36] The reference was argued before the Ontario Court of Appeal on 18 April 2019, and the decision is pending.

3. THE MANITOBA CHALLENGE

Manitoba filed its own challenge to the *GGPPA,* arguing once again the *GGPPA* is not within federal jurisdiction. Its Notice of Application for judicial review was filed in the Federal Court on 24 April 2019.[37]

Manitoba has perhaps the most interesting history with the federal climate regime. In concert with Saskatchewan, it initially refused to support the Pan-Canadian Framework.[38] It subsequently commissioned a legal opinion from Bryan Schwartz, a constitutional law Professor at the University of Manitoba, on the validity of the then-proposed *GGPPA*.[39]

---

29 See *R v Crown Zellerbach Canada Ltd*, [1988] 1 SCR 401.
30 *Re GGPPA* (SK), *supra* note 23 at para 138.
31 *Ibid* at para 210.
32 *Ibid* at para 163.
33 Ontario, News Release, "Ontario Introduces Legislation to End Cap and Trade Carbon Tax Era in Ontario" (25 July 2018), online: <news.ontario.ca/ene/en/2018/07/ontario-introduces-legislation-to-end-cap-and-trade-carbon-tax-era-in-ontario.html>.
34 Ontario, News Release, "Ontario Leads Growing Opposition to the Federal Carbon Tax" (21 December 2018), online: <news.ontario.ca/opo/en/2018/12/ontario-leads-growing-opposition-to-the-federal-carbon-tax.html>.
35 *Supra* note 27.
36 *Re GGPPA* (ON), *supra* note 24 at paras 102–22.
37 Manitoba Application, *supra* note 25.
38 *Supra* note 12.
39 Bryan P Schwartz, "Legal Opinion on the Constitutionality of the Federal Carbon Pricing Benchmark & Backstop Proposals," online: <manitoba.ca/asset_library/en/climatechange/federal_carbon_pricing_benchmark_backstop_proposals.pdf>.

The Schwartz opinion concluded a court would be unlikely to refuse federal jurisdiction over the proposed *GGPPA*. Manitoba, which had its own "Made-in-Manitoba" plan and proposed carbon tax of $25 per tonne of CO_2e, subsequently joined the Pan-Canadian Framework.[40] Its proposed tax was withdrawn in October 2018 when Ottawa indicated it was insufficient to meet the federal requirements.[41] Manitoba is now one of the provinces subject to the federal regime.[42]

C. ALBERTA'S NEW METHANE RULES

Methane is a particularly potent GHG. It is estimated to have 25 times the greenhouse effect of CO_2 in the atmosphere over a 100-year period. The oil and gas industry was the source of approximately 70 percent of Alberta's total methane emissions in 2014.[43]

The Alberta Energy Regulator (AER) has developed requirements to reduce methane emissions from upstream oil and gas operations by 45 percent relative to 2014 levels by 2025.[44] The new requirements were released in December 2018, and include Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting;[45] Directive 017: Measurement Requirements for Oil and Gas Operations;[46] Manual 015: Estimating Methane Emissions;[47] and Manual 016: How to Develop a Fugitive Emissions Management Program.[48]

These new directives and manuals impose greater requirements on the industry to monitor, measure, and report methane emissions. New facilities will generally be held to more stringent standards than existing facilities, and non-compliance will be addressed through applicable legislation, such as the *Responsible Energy Development Act*,[49] and will depend on the magnitude of the infraction and the operator history.[50]

---

40 Canada and Manitoba, News Release, "Canada Welcomes Manitoba to the Pan-Canadian Plan for Clean Growth and Climate Action" (23 February 2018), online: <news.gov.mb.ca/news/index.html?item=43197>.

41 Manitoba, News Release, "Manitoba Rejects Carbon Tax, Moves Ahead with Made-in-Manitoba Climate and Green Plan" (3 October 2018), online: <news.gov.mb.ca/news/index.html?item=44667>.

42 *GGPPA*, *supra* note 3, Schedule 1.

43 Alberta Energy Regulator, "Methane Reduction," online: <aer.ca/providing-information/by-topic/methane-reduction>.

44 *Ibid*.

45 Alberta Energy Regulator, "Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting" (13 December 2018), online: <aer.ca/documents/directives/Directive060_2020.pdf>.

46 Alberta Energy Regulator, "Directive 017: Measurement Requirements for Oil and Gas Operations" (13 December 2018), online: <aer.ca/documents/directives/Directive017.pdf>.

47 Alberta Energy Regulator, "Manual 015: Estimating Methane Emissions" (December 2018), online: <aer.ca/documents/manuals/Manual015.pdf>.

48 Alberta Energy Regulator, "Manual 016: How to Develop a Fugitive Emissions Management Program" (December 2018), online: <aer.ca/documents/manuals/Manual016.pdf>.

49 *Responsible Energy Development Act*, SA 2012, c R-17.3, s 70 [*REDA*].

50 Alberta Energy Regulator, "Manual 013: Compliance and Enforcement Program" (February 2016), online: <aer.ca/documents/manuals/Manual013.pdf>.

III. ELECTRICITY

A. POWER MARKETS

1. ALBERTA'S PROPOSED CAPACITY MARKET

Alberta's electricity market has been deregulated since 1996. It is currently operated as a wholesale power market in which generators bid power into the power pool and receive the market price in each hour. In this "energy-only" market, electricity generators are paid solely for the electricity they supply to the market. This is in contrast to, for example, a price based on cost of service or the energy they are capable of producing.[51]

In November 2016, the Alberta government endorsed the Alberta Electric System Operator's (AESO) recommendation to transition to a capacity market (and energy market) for electricity. A capacity market is a market where future generation capacity (such as generation potential) is purchased in advance, in order to ensure sufficient capacity exists to meet demand when it arises. Parties bid for future capacity through competitively auctioned contracts designed to pay the fixed capital costs of generation and earn revenue from the spot market. The first capacity auction is expected to commence in November 2019.[52]

Uncertainty aside, the change to a capacity market was recommended by the AESO because it is of the view that it will:

- ensure reliability as Alberta's electricity system evolves;
- increase stability of prices;
- provide greater revenue certainty for generators;
- maintain competitive market forces and drive innovation and cost discipline; and
- support policy direction and be adaptable for the future.[53]

This recommended change is, in part, motivated by a shift in the generation supply mix in Alberta. As a result of both federal and provincial initiatives to phase out coal and increase renewable and low-emission electricity production, more and more power is being sourced from renewable generation. Renewable electricity has a marginal cost of zero — that is, once the facility is built, it effectively costs nothing additional to produce the electricity. The fuel sources — sun and wind — are free. Traditional sources of reliable base generation, such as

51 Alberta Electric System Operator, "Guide to Understanding Alberta's Electricity Market," online: <aeso.ca/aeso/training/guide-to-understanding-albertas-electricity-market/>.

52 Alberta Electric System Operator, "Overview of the Alberta Capacity Market" at 1, online: <aeso.ca/assets/Uploads/CMD-4.0-Section-1-Overview-of-Capacity-Market-FINAL.pdf> [AESO Overview].

53 Alberta Electric System Operator, "Capacity Market Transition," online: [web.archive.org/web/20190429161501/https://www.aeso.ca/market/capacity-market-transition/].

coal and natural gas, have a greater marginal cost. A capacity market is seen as a way to encourage investment in the energy market, especially in traditional base load generation.[54]

In June 2018, the Alberta Legislature passed Bill 13, *An Act to secure Alberta's electricity future*, creating the legal framework for the transition.[55] The AESO is to design the rules for the establishment and operation of the capacity market (including auctions, participants, and payment calculations).[56] Under Bill 13, all AESO rules must be approved by the Alberta Utilities Commission (AUC), which is a change from the current system where AESO rules are deemed to be approved unless there is a participant objection.[57] This, combined with the added complexity of a capacity market, would mean a substantially revised role for the AUC. The first set of provisional independent system operator rules for the capacity market are currently under review by the AUC.[58] The proposed change to a capacity market is controversial, and concerns have been expressed that the AESO's market design has overestimated future demand and the transition will result in an over-procurement of supply and significant costs to consumers. An AUC decision is expected on 31 July 2019. However, the new conservative government has stated its intention to consult on whether to proceed with the capacity market at all, so the outcome of the proposed transition is uncertain.[59]

2. ALBERTA DISTRIBUTION SYSTEM INQUIRY

The AUC has initiated an inquiry into Alberta's natural gas and electric distribution systems. The fundamental objective of the inquiry is to "establish the regulatory agenda for subsequent proceedings of the Commission that will consider, and then implement, the regulatory framework necessary to accommodate the economic and technological forces that are transforming the market structure governing energy distribution by public utilities."[60]

The inquiry will be heard by way of three separate modules: Module One will focus on emerging trends in technology and innovation potentially affecting distribution systems, Module Two will examine the interplay between these emerging trends and the forces affecting the business models and regulatory frameworks governing distribution utilities, and Module Three will examine the ability of the current rate designs to send appropriate price signals.[61] Following the conclusion of the inquiry it is expected that the AUC will initiate proceedings to consider necessary changes to rate structures, rate designs, and terms of service.[62] At the time of writing, more than 45 parties have registered to participate.

---

54 David P Brown, "Capacity Market Design: Motivation and Challenges in Alberta's Electricity Market" (2018) 11:12 U Calgary School Public Policy Publications 1 at Summary, 5–6.

55 Bill 13, *An Act to secure Alberta's electricity future*, 4th Sess, 29th Leg, Alberta, 2018, cl 2(29) [Bill 13]. The Bill came into force in large part on 1 August 2018, with a few clauses coming into force earlier, and some on proclamation.

56 AESO Overview, *supra* note 52 at 1; Bill 13, *ibid* at Summary, 5–6.

57 *Electric Utilities Act*, SA 2003, c E-5.1, s 20.2(1).

58 *Alberta Capacity Market* (23 July 2018), Calgary, Alberta Utilities Commission 23757 (application), online: <auc.ab.ca/Pages/Alberta-capacity-market.aspx>.

59 UCP Platform, *supra* note 26 at 36.

60 *Distribution System Inquiry* (29 March 2019), Calgary, Alberta Utilities Commission 24116 (letter from the AUC to registered parties on scope and process) at para 9, online: <auc.ab.ca/Shared%20 Documents/Projects/24116_X0106-AUCletter-Scopeandprocess.pdf>.

61 *Ibid* at paras 11–14.

62 *Ibid* at para 10.

3. ONTARIO'S MARKET RENEWAL INITIATIVE

Ontario's Independent Electricity System Operator (IESO) has been working alongside the Market Surveillance Panel and Ontario electricity sector stakeholders since April 2016 to coordinate and create a proposed set of market reforms to the province's electric market. The reform, referred to as Ontario's Market Renewal Initiative, consists of four main initiatives:

1. transition from a two-schedule market to a single schedule market to reduce the cost of scheduling and dispatch;

2. a "day-ahead market" to provide greater operational certainty to the IESO and greater financial certainty to market participants, both lowering the cost of producing electricity;

3. an enhanced real-time unit commitment to reduce the cost of scheduling and dispatching; and

4. an incremental capacity auction for meeting long-term supply needs.[63]

The IESO commissioned a benefits case assessment of the Ontario Market Renewal Initiative, which was published in April 2017.[64] The resulting report found that:

1. estimated province-wide efficiency and customer benefits of the Market Renewal Initiative significantly outweigh estimated implementation costs;

2. benefits from the Market Renewal Initiative are expected to grow over time;

3. the Market Renewal Initiative will create a competitive framework for effectively incorporating new and emerging technologies;[65]

4. there are opportunities to enhance the cost-benefit ratio of the market renewal initiative by learning from the experiences of other jurisdictions.

The IESO has released its high-level design for each of the four main market renewal initiatives for stakeholder comment and is expected to move into the detail design phase in 2019.

---

63 Independent Electricity System Operator, "Market Renewal: Background," online: <ieso.ca/en/Market-Renewal/Background/Overview-of-Market-Renewal>.

64 Johannes Pfeifenberger et al, "The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project" (Boston: The Brattle Group, 2017), online: <brattle.com/news-and-knowledge/publications/the-future-of-ontarios-electricity-market-a-benefits-case-assessment-of-the-market-renewal-project>.

65 *Ibid* at iii.

4. NEXTBRIDGE EAST-WEST TIE LINE TRANSMISSION PROJECT

The East-West Tie Line Transmission Project was designated by the Ontario government as a "priority [transmission] project" in northwestern Ontario, required to ensure long-term electricity supply reliability in an area where demand is expected to rise with increased mining activity.[66] In 2013, the Ontario Energy Board (OEB) designated NextBridge Infrastructure (NextBridge) to undertake development work for the project. Such designation did not provide NextBridge the right to build the project or apply for leave to construct.[67]

NextBridge and Hydro One Networks Inc. made competing applications to the OEB in July 2017 for the necessary approvals for leave to construct the project. The OEB did not grant leave at the time, finding that the risks of both proposals were "disproportionately visited upon ratepayers."[68]

On the basis of the priority status of the project and the expected in-service date of 2020, the Ontario Government issued an Order in Council and directive on 30 January 2019, requiring the OEB to amend the NextBridge electricity transmission licence to allow NextBridge to also develop and construct the project.[69] The OEB issued Decision and Order granting leave to construct to NextBridge on 11 February 2019.[70]

B. RENEWABLES

1. ALBERTA'S RENEWABLE ELECTRICITY PROGRAM

Closely related to Alberta's new proposed capacity market is the Renewable Electricity Program (REP). As part of Alberta's Climate Leadership Plan, the province committed to phasing out coal generation by 2030 and to sourcing 30 percent of electricity generation through renewables by 2030. In order to achieve these goals while ensuring reliable electricity supply, the province created the REP — a competitive bidding process for renewable energy projects in the province.[71]

Renewable energy is energy that comes from a source that is naturally occurring and replenishes after use (geothermal, hydro, solar, sustainable biomass, and wind).[72] By 17 December 2018, the AESO had conducted three rounds of procurement, which have succeeded in securing approximately 1360 megawatts of renewable electricity.[73]

---

66 Government of Ontario, "Achieving Balance: Ontario's Long-Term Energy Plan" at 48, online: <ontario.ca/document/2013-long-term-energy-plan. See also online: <www.nextbridge.ca/project_info>.

67 *Re Upper Canada Transmission Inc (on behalf of Nextbridge Infrastructure)* (20 December 2018), EB-2017-0182 at 1, online: OEB <www.rds.oeb.ca/HPECMWebDrawer/Record/629660/File/document>.

68 *Ibid* at 2.

69 OC 52/2019 (29 January 2019), online: <ontario.ca/orders-in-council/oc-522019>.

70 *Re Upper Canada Transmission Inc (on behalf of Nextbridge Infrastructure)* (11 February 2019), EB-2017-0182, online: OEB <www.rds.oeb.ca/HPECMWebDrawer/Record/634097/File/document>.

71 Government of Alberta, "Climate Leadership Plan: Implementation Plan 2018-19" (Edmonton: Government of Alberta, 2018) at 6, online: <open.alberta.ca/dataset/da6433da-69b7-4d15-9123-01f76004f574/resource/b42b1f43-7b9d-483d-aa2a-6f9b4290d81e/download/clp_implementation_plan-jun07.pdf>.

72 Government of Alberta, "Renewable Electricity Program," online: <alberta.ca/renewable-electricity-program.aspx>.

73 Alberta Electric System Operator, "REP Results," online: <aeso.ca/market/renewable-electricity-program/rep-results/>.

The first three rounds of bidding used a payment mechanism called an Indexed Renewable Energy Credit (REC) or "Contract for Difference." Under a REC, winning bidders are paid the difference between the pool price and the bid price (the bid price is the lowest acceptable dollar per megawatt hour ($/MWh) the proponent can support the project on; the pool price is the hourly spot price of electricity when demand is matched up with supply). If the pool price is higher than the bid price, the proponent returns the difference to the government.[74] The result is a guaranteed $/MWh price, no higher, no lower.

REP round four is currently being developed (AESO recommendations are due by 3 June 2019) and is planned to add up to 400 megaWatts (MW) in partnership with Indigenous communities.[75] On 26 February 2019, the province announced a new long-term plan for the REP, which includes interim targets and a plan for accommodating the growth of the electricity system.[76] However, the change in government that occurred in April 2019 may create uncertainty for the future of the REP.[77]

2. SASKATCHEWAN RENEWABLES PROCUREMENT

Saskatchewan has committed to achieving 30 percent wind generating capacity and 50 percent overall renewable capacity by 2030 as part of its broader commitment to reducing greenhouse gas emissions in the electricity sector by 40 percent from 2005 levels.[78] Wind power capacity is anticipated to increase from 221 MW (the current installed capacity) to approximately 2100 MW by 2030. So far, the procurement process has secured the Blue Hill Wind Energy Project (177 MW)[79] and the Golden South Wind Energy Facility (200 MW).[80]

Saskatchewan also plans to add 60 MW of ground solar generation by 2021 through a combination of competitive procurement, a partnership with First Nations Power Authority, and community projects.[81]

---

74 Alberta Electric System Operator, "About the Program," online: <aeso.ca/market/renewable-electricity-program/about-the-program/>.

75 Letter from Margaret McCuaig-Boyd, Alberta Minister of Energy, to Michael Law, President and CEO of AESO (13 February 2019), online: <aeso.ca/assets/Uploads/02-13-19-REP-Round-4-direction-letter.pdf>.

76 Government of Alberta, News Release, "Long-Term Renewables Plan Powers Jobs, Investment" (26 February 2019), online: <alberta.ca/release.cfm?xID=62600ACA2C8C4-9C9C-1198-C73B9AB047 1F6EDF>. Note that REP round two awarded over 360 MW and each project was required to include Indigenous equity ownership.

77 UCP Platform, *supra* note 26 at 36.

78 SaskPower, News Release, "The Path to 2030: SaskPower Updates Progress on Renewable Energy" (28 November 2017), online: <saskpower.com/about-us/media-information/news-releases/2018/03/the-path-to-2030-saskpower-updates-progress-on-renewable-electricity>.

79 Government of Saskatchewan, News Release, "Government of Saskatchewan Approves Blue Hill Wind Energy Project" (20 September 2018), online: <www.saskatchewan.ca/government/news-and-media/2018/september/20/blue-hill-wind-project>.

80 SaskPower, "Golden South Wind Energy Facility," online: <saskpower.com/Our-Power-Future/Infrastructure-Projects/Construction-Projects/Current-Projects/Golden-South-Wind-Energy-Facility>.

81 SaskPower, News Release, "SaskPower's Next Utility-Scale Solar Project Moves to RFP Phase" (23 April 2019), online: <saskpower.com/about-us/media-information/news-releases/SaskPowers-next-utility-scale-solar-project-moves-to-RFP-phase>.

3. CLEAN FUEL STANDARD

In December 2018, Environment and Climate Change Canada released the Regulatory Design Paper for Clean Fuel Standard.[82] The Regulatory Design Paper is intended to present key elements of the design of the Clean Fuel Standard regulations. The objective of the Clean Fuel Standard is "to achieve 30 million tonnes of annual reductions in greenhouse gas emissions by 2030, making an important contribution to the achievement of Canada's target of reducing national emissions by 30% below 2005 levels by 2030."[83]

The Clean Fuel Standard regulations will separate requirements for liquid, gas, and solid fossil fuels (the fuel streams).

Key elements of the design of the Clean Fuel Standard regulations, as provided in the Regulatory Design Paper, include:

- requirement for the liquid stream that involves the reduction of the carbon intensity of liquid fuels by ten grams of CO_2e per megajoule below their reference carbon intensity by 2030;

- "actions that generate credits, including fuel-switching by end-users in the liquid stream";

- early-action credits where action is taken in all three fuel streams after the publication of final regulations for the liquid stream, expected to occur in 2020; and

- "trading credits between fuel streams."[84]

A draft of the Clean Fuel Standard regulations for the liquid stream is planned for publication in the summer of 2019, with final regulations planned for 2020.[85] Final regulations for the gas and solid fuel streams are projected to be released in 2021.[86]

IV. OFFSHORE

A. NOVA SCOTIA ABANDONMENT

Natural gas production off the east coast of Canada has ceased for the foreseeable future. Exxon Mobil is the operator of the Sable Offshore Energy Project (Sable Project)[87] — Canada's first offshore natural gas development project. The Sable Project, made up of seven

---

82 Environment and Climate Change Canada, "Clean Fuel Standard: Regulatory Design Paper" (Gatineau: ECCC, 2018), online: <canada.ca/content/dam/eccc/documents/pdf/climate-change/clean-fuel-standard-regulatory-design-paper-2018-en-1.pdf>.

83 *Ibid* at 2.

84 *Ibid* at 2–3.

85 *Ibid* at 1.

86 *Ibid* at 17.

87 The Sable Project is owned by ExxonMobil Canada Properties (50.8 percent), Shell Canada Limited (31.3 percent), Imperial Oil Resources (9 percent), Pengrowth Energy Corporation (8.4 percent), and Mosbacher Operating Ltd. (0.5 percent) (Sable Project, "About the Project," online: <soep.com/about-the-project>).

offshore platforms spread over 200 square kilometres near Sable Island in the North Atlantic Ocean, began producing in 1999 and is now being decommissioned due to naturally declining production.

Formal application for Leave to Abandon the NEB-regulated Sable Project facilities, which include a 200-kilometre long, 26-inch wide mostly subsea pipeline and the Goldboro Gas Plant located in Guysborough County, Nova Scotia, was made to the NEB in March 2018. The gathering pipeline is regulated by the NEB, the Nova Scotia Utility and Review Board (NSUARB), and partially by the Canada Nova Scotia Offshore Petroleum Board (CNSOPB). The Goldboro Gas Plant is regulated by the NEB, NSUARB, and Nova Scotia Environment. The decommissioning will be a significant project, with several factors to be considered, including potential impacts on Indigenous interests, affected landowners, fishers, navigation, risk of product release, safety issues, economic impacts, and so on. [88]

Deep Panuke, the only other natural gas project offshore the coast of Nova Scotia, will also be decommissioned. Encana, the operator of Deep Panuke, announced that production from that project, which began in 2013 and more recently was only conducted seasonally,[89] permanently ceased on 7 May 2018.[90]

Decommissioning and abandonment of the Deep Panuke development will require approvals from the NEB and the CNSOPB. Encana applied to the NEB for Leave to Abandon the Deep Panuke 175-kilometre long, 22-inch wide subsea pipeline and associated onshore facilities on 19 June 2018. Like the nearby Sable Project, the decommissioning will be a large project potentially affecting many parties.[91]

B. M&NP TOLL SETTLEMENT

The Maritimes & Northeast Pipeline (M&NP) is a bi-directional natural gas pipeline originally developed to transport natural gas from the Sable Project to markets in Atlantic Canada and the northeastern US. Since 2007, M&NP has also transported production from the McCully natural gas field in New Brunswick and, since 2013, natural gas from Deep Panuke. When offshore production has been insufficient to meet domestic demand, natural gas flows through an import and export interconnect point with the US portion of M&NP into Canada. As a result of declining offshore production ultimately leading to the decommissioning of the Sable Project and Deep Panuke, throughput on M&NP has generally been decreasing over time.[92]

---

88 National Energy Board, "ExxonMobil Canada Ltd. – Sable Offshore Energy Project – Abandonment of Gathering Pipeline and the Goldboro Gas Plant," online: <cer-rec.gc.ca/pplctnflng/mjrpp/xxnm blsblffshr/index-eng.html>.

89 National Energy Board, "Encana Corporation – Abandonment of Deep Panuke Offshore Gas Development," online: <cer-rec.gc.ca/pplctnflng/mjrpp/ncndppnk/index-eng.html> ["Abandonment of Deep Panuke"].

90 Canada-Nova Scotia Offshore Petroleum Board, "Offshore Activity: Deep Panuke Offshore Gas Project," online: <cnsopb.ns.ca/offshore-activity/offshore-projects/deep-panuke-offshore-gas-project>.

91 "Abandonment of Deep Panuke," *supra* note 89.

92 NEB, "Pipeline Profiles: Maritimes & Northeast," online: <cer-rec.gc.ca/nrg/ntgrtd/pplnprtl/pplnprfls/ ntrlgs/mnp-eng.html>.

In June 2017, M&NP applied to the NEB for approval of its 2017–2019 Toll Settlement.[93] As part of the application, M&NP sought to, among other things, accelerate depreciation and decrease return on equity over the settlement period. Heritage Gas Limited and its affiliates opposed the settlement on the basis that, among other things, the remaining captive shippers should not face the full costs of depreciation past 2019.[94] It sought to have M&NP's largest shippers, whose transportation agreements end in 2019, bear a greater portion of the depreciation costs than proposed under the settlement.[95]

The NEB approved the settlement as presented on the basis that it would result in tolls that are just and reasonable.[96] The NEB agreed with the M&NP position that the accelerated depreciation and reduced return on equity were consistent with the toll principle of intergenerational equity and responsive to the declining throughput on the system.[97] The NEB also held that it was not appropriate to fully accelerate depreciation such that the capacity contracted by shippers on the system post-2019 would be fully depreciated by the end of the settlement period; such an approach would result in current shippers bearing undue burden related to future costs and benefits.[98]

The NEB found it was necessary to set appropriate abandonment contribution amounts on M&NP given the expected reduction in billing determinants and directed M&NP to file an application proposing an updated collection period and annual collection amount for the settlement period and beyond.[99] The resulting proceeding is discussed in the section below.

C. M&NP ABANDONMENT FUNDING

In the 2017–2019 M&NP Toll Settlement decision, the NEB expressed concern that the costs to abandon the M&NP system may have increased since the approval of M&NP's abandonment toll surcharge (ATS) and annual contribution amount (ACA) in 2015[100] and, therefore, directed the filings described above.

On 16 April 2018, M&NP filed its application for approval of a 2018–2019 ATS and ACA.[101] M&NP requested the NEB set the current ATS and ACA on an interim basis effective 1 May 2018.[102]

---

93 *Maritimes & Northeast Pipeline Management Ltd (MN&P) Application for Approval of a 2017-2019 Toll Settlement* (30 June 2017), Calgary, National Energy Board RHW-003-2017 (application), online: <apps.cer-rec.gc.ca/REGDOCS/File/Download/3297302>.

94 *Maritimes & Northeast Pipeline Management Ltd (MN&P) Application for Approval of a 2017-2019 Toll Settlement* (20 November 2017), Calgary, National Energy Board RHW-003-2017 (written arguments of Heritage Gas Limited), online: <apps.cer-rec.gc.ca/REGDOCS/File/Download/3390148>.

95 *Ibid.*

96 *Maritimes & Northeast Pipeline Management Ltd (MN&P) Application for Approval of a 2017-2019 Toll Settlement* (1 March 2018), RHW-003-2017, online: NEB <apps.cer-rec.gc.ca/REGDOCS/File/Download/3489952>.

97 *Ibid* at 17.

98 *Ibid.*

99 *Ibid* at 20–21.

100 *Ibid.*

101 *Maritimes & Northeast Pipeline Management Ltd (MN&P) Application for Approval of a 2017-2019 Toll Settlement* (16 April 2018), Calgary, National Energy Board RHW-003-2017 (2018-2019 abandonment toll surcharge and annual contribution amount application), online: <apps.cer-rec.gc.ca/REGDOCS/File/Download/3537737>.

102 *Ibid* at para 34.

The application was approved as filed, increasing the ATS and ACA for the settlement period and in the interim.[103] In its decision, the NEB held that, "[w]hile pipeline companies are ultimately responsible for the full costs of constructing, operating and abandoning their pipelines … abandonment costs are a legitimate cost of providing service and are recoverable upon Board approval from users of the system."[104] The NEB found that the M&NP proposal reflected the changing contract levels over the relevant time period and better matched payment of abandonment costs with the economic use of the system, consistent with the principle of intergenerational equity.[105]

V. OIL AND GAS

A. PROVINCIAL RAILCARS LEASE

On 19 February 2019, Alberta's New Democratic Party government, led by Premier Notley, signed contracts with Canadian National Railway Co. and Canadian Pacific Railway Ltd. to lease 4,400 railcars for $3.7 billion over a three-year period. The railcars were leased with the intention of shipping up to 120,000 barrels per day (bpd) of crude oil out of Alberta. This oil-by-rail plan was implemented in an effort by the NDP provincial government to narrow the Canadian oil price differential and alleviate transportation constraints in Alberta.

The growing oil price differential and export bottlenecks have largely resulted from a recent pattern of legal challenges and regulatory uncertainty in both Canada and the US with respect to pipeline projects. Regulatory and legal hurdles effectively stalled the TMEP and killed the Northern Gateway and Energy East projects. The fate of the Keystone XL pipeline remains uncertain. The consequence was an increased oil price differential between Canada and the US benchmarks, reaching as high as US$43 per barrel in late 2018.

Premier Notley (as she then was) requested the federal government provide $350 million in assistance to fund the railcar lease. The federal government declined to commit the funds despite assurance from the province that the purchases would serve as a hedge against future pipeline delays. While shipping crude oil by rail is typically more expensive than transport by pipeline, few other viable alternatives to increase the transportation capacity have been identified. The plan comes after the government's mandated production cuts.

The service was slated to begin in July 2019 with about 20,000 bpd increasing to 120,000 bpd a day by mid-2020. However, Alberta's new Premier has stated his government will seek to cancel the contracts. Since this announcement, a number of Canada's major oil producers have suggested that the industry might take over the contracts. As of the date of writing, the future of these contracts remains uncertain.

---

103 *Maritimes & Northeast Pipeline Management Ltd (MN&P) Application for Approval of a 2017-2019 Toll Settlement* (18 June 2018), Calgary, National Energy Board RHW-003-2017 (approval of 2018-2019 abandonment toll surcharge and annual contribution amount), online: <apps.cer-rec.gc.ca/REG DOCS/File/Download/3580506>.

104 *Ibid* at 2.

105 *Ibid*.

B. NEB REPORT ON OIL PIPELINE AND RAIL OPTIMIZATION

The NEB met with approximately 30 pipeline companies, producers, shippers, associations, government agencies, and experts to provide requested advice to the Canadian Minister of Natural Resources on oil transportation optimization out of Western Canada.[106] The NEB also sought and received public comments via an online forum. In its final report,[107] the NEB concluded:

- pipeline capacity use is currently optimized in that there is no unused available capacity (98 percent capacity utilization in Q4 2018, which is an effective maximum);

- the NEB has not identified compliance concerns with respect to the nomination and verification rules (which vary by pipeline) in the NEB-approved tariffs; however, it determined that existing verification procedures as a whole allow shippers to nominate more oil to pipelines than can be supplied. Integrated producers and shippers with storage and refinery capacity have a greater ability to acquire pipeline capacity, but it is observed that this greater ability largely came about as a result of investments made. Improving verification through the whole supply chain (which extends to facilities outside of the NEB's jurisdiction and cannot be accomplished by the NEB alone) might result in better adherence to common carrier principles but would result in reallocation and not increased pipeline utilization. More pipeline capacity is required to increase utilization; and

- further optimization solutions are achievable, but not in the near term. Building more upgrading capacity (thereby reducing diluent volumes needed) would increase transportation volumes, but the investment climate remains uncertain, especially in the face of additional pipeline capacity expected to come on in the next few years.

Rail transportation is subject to various limitations. It is more expensive, less economic as price differentials narrow, generally more complex, and subject to long lead times and causes impacts on other railed goods. The investment climate is also uncertain, and Canadian rail infrastructure is operating at or near capacity (oil only makes up a small fraction of the total commodities moved by rail).

The NEB notes that Western Canadian oil prices have recovered and differentials with West Texas Intermediate have narrowed recently, but largely as a result of the Alberta government's production curtailment program.[108]

---

106 The report was provided in response to a request by the Minister. See National Energy Board, News Release, "NEB Releases Report on Optimizing Oil Pipeline and Rail Capacity out of Western Canada" (15 March 2019), online: <cer-rec.gc.ca/bts/nws/nr/2019/nr05-eng.html>.

107 National Energy Board, "Optimizing Oil Pipeline and Rail Capacity out of Western Canada: Advice to the Minister of Natural Resources" (Calgary: NEB, 2019), online: <cer-rec.gc.ca/nrg/sttstc/crdlnd ptrlmprdct/rprt/2019ptmzngcpct/2019ptmzngcpct-eng.pdf>.

108 *Ibid* at 5.

The NEB suggests greater transparency regarding all aspects of the oil supply chain in Canada would improve market function, but it observes that not many market participants have an incentive to provide data to the public; therefore, government intervention is likely required to collect and disseminate data.[109]

In the end, this report paints a picture of complexity that suggests any intervention to improve optimization would require rule changes across several jurisdictions and investment in the face of considerable uncertainty.

C. REPORT ON HYDRAULIC FRACTURING IN BRITISH COLUMBIA

The report of the Scientific Hydraulic Fracturing Review Panel (the Panel) on Hydraulic Fracturing in British Columbia was released in February 2019.[110] The Panel was tasked by the British Columbia Minister of Energy, Mines and Petroleum Resources with answering two questions.

1. Does British Columbia's regulatory framework adequately manage potential risks or impacts to safety and the environment that may result from the practice of hydraulic fracturing?

2. How could British Columbia's regulatory framework be improved to better manage safety risks, risk of induced seismicity, and potential impacts to water?[111]

The report contains several recommendations and findings relative to hydraulic fracturing and underground fluid disposal. Much of the discussion concerns knowledge gaps and recommendations for more research, regulation, and transparency. Notable is the discussion of induced seismic events and methane leaks. It is observed that no damage has resulted from any of the induced seismic events, though many incidents have been felt. The report recognizes significant improvement by industry, particularly around water use and recycling. Ultimately, with its precautionary approach, it is difficult to avoid the conclusion that the report will result in more regulation and increased monitoring and communication requirements.[112]

D. ENBRIDGE MAINLINE APPORTIONMENT

The Enbridge Mainline delivers crude oil, natural gas liquids, and refined petroleum products from Edmonton, Alberta, to the US Midwest and Sarnia, Ontario. It is the largest oil export pipeline system in Canada.[113]

---

109 *Ibid* at 6.

110 Government of British Columbia, News Release, "Hydraulic Fracturing Scientific Review Report Released" (19 March 2019), online: <news.gov.bc.ca/releases/2019EMPR0008-000427>.

111 Scientific Hydraulic Fracturing Review Panel, "Scientific Review of Hydraulic Fracturing in British Columbia" (Victoria: Government of British Columbia, 2019), online: <www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-gas-oil/responsible-oil-gas-development/scientific_hydraulic_fracturing_ review_panel_final_report.pdf>.

112 *Ibid*.

113 For more information see National Energy Board, "Pipeline Profiles: Enbridge Mainline," online: <cer-rec.gc.ca/nrg/ntgrtd/pplnprtl/pplnprfls/crdl/nbrdgmnln-eng.html>.

Unlike the other main pipelines exporting crude to markets outside of Alberta, the Enbridge Mainline does not offer long-term contract capacity. Because of constrained export pipeline capacity, nominations for transportation capacity regularly outstrip available capacity.[114]

When nominations are collectively greater than the available capacity, capacity is apportioned on a pro rata basis relative to total demand. Sometimes apportionment on the Enbridge Mainline reaches over 50 percent.[115]

On 24 May 2018, Enbridge announced it would implement a new supply verification procedure (SVP) — a mechanism to verify that shippers actually have adequate supply to fill their monthly volume nominations for transportation. The SVP was to be implemented in July 2018 and would have limited the volumes that shippers were permitted to nominate without further verification to their 12-month rolling average of actual volumes transported on the Enbridge Mainline, plus an additional percentage allowance depending on the crude type. After meeting and consulting with shippers and later receiving feedback of financial harm that was being experienced as trading began for July nominations, Enbridge decided to cancel the implementation of the new SVP.[116]

In response, BP Products North America filed a complaint with the NEB, which was not directed at the proposed new SVP itself, but rather at Enbridge's actions in exercising its discretion to establish verification procedures (BP Complaint).[117] The BP Complaint was founded on the following three grounds having regard to Enbridge:

1. introducing and then revoking the SVP during the ordinary "trading period" when crude oil is typically bought and sold and scheduling decisions are made, creating unreasonable and unnecessary uncertainty in the market;

2. failing to provide for sufficient advance notice to and consultation with shippers of the proposed implementation and then revocation of the new SVP; and

3. imposing market risks on shippers by failing to provide any certainty of future implementation.

The NEB established a process to solicit comments on the BP Complaint. Enbridge responded early to the BP Complaint by providing qualified assurances that it would not implement a new SVP in the near term and would not otherwise seek to do so in the future during a trading period or without at least a month's advance notice. Letters of comment

114 The other main pipelines are Trans Mountain Pipeline, Express Pipeline, and Keystone Pipeline (all of these pipelines are NEB regulated).

115 National Energy Board, "Market Snapshot: What is Pipeline Apportionment?" online: <cer-rec.gc.ca/nrg/ntgrtd/mrkt/snpsht/2018/08-03pplnpprtnmnt-eng.html>.

116 Letter from Jennifer Geggie, Vice President, Global Oil Americas, BP Products North America Inc., to Sheri Young, Secretary, National Energy Board (6 June 2018) (notice of complaint pursuant to part IV of the *National Energy Board Act*), Appendix B, online: <apps.cer-rec.gc.ca/REGDOCS/File/Download/3577836> [A92328 Letter]; Letter from Brian Johnson, Vice President, Customer Service, Enbridge Pipelines Inc, to Sheri Young, Secretary, National Energy Board (11 June 2018) (Enbridge response to notice of complaint), online: <apps.cer-rec.gc.ca/REGDOCS/File/Download/3579829>.

117 A92328 Letter, *ibid*.

were subsequently received by the NEB from a number of interested parties who largely supported the BP Complaint, but mostly indicated that they did not think any further NEB process was required at the time in light of Enbridge's revocation of the SVP. In its reply to the letters of comment, Enbridge made additional commitments to conduct meaningful consultation regarding proposed solutions to over-nomination issues and to not seek to implement any new SVP without first seeking NEB approval. The NEB concluded that the Enbridge commitments addressed the BP Complaint and that no further process was required at the time. The NEB also directed that any future substantive changes to Enbridge's verification procedures should be reflected in Enbridge's tariff, which would then have to be filed with the NEB for approval.[118]

E. THE CRESCENT POINT COMPLAINT

On 9 June 2017, Crescent Point Resources Partnership (Crescent Point) filed a complaint to the NEB regarding the Westspur Pipeline, which is owned by Tundra Energy Marketing Limited (TEML) and operated by TEML Westspur Pipeline Limited (TEML Westspur).[119] Crescent Point ships crude oil on the Westspur Pipeline, the Weyburn Pipeline system (Weyburn Pipeline) operated by TEML Weyburn Pipelines Limited, and the Saskatchewan Pipeline Gathering System (Saskatchewan Pipeline) operated by TEML Saskatchewan Pipelines Limited.

The complaint initiated by Crescent Point resulted from changes made by TEML Westspur to the way equalization of crude quality differences (EQ) was carried out on the Weyburn and Saskatchewan Pipelines. Specifically, early in 2017, TEML Westspur did not provide the Quality Equalization Steering Committee report to shippers on the pipeline, which resulted in shippers being unable to ensure that EQ calculations and valuation adjustments were correctly carried out. In addition, in 2017, TEML notified shippers of proposed changes to the TEML Westspur No. 85 Tariff Rules and Regulations. Two key changes included change to the vapour pressure specifications and the removal of TEML's obligation as a carrier to comply with the industry-established EQ process on the Saskatchewan Pipeline and the Weyburn Pipeline.

Crescent Point's complaint to the NEB was twofold:

1. changes to operational practices by TEML Westspur were inconsistent with applicable Westspur Tariff Rules and Regulations; and

2. there was potential for shipper information provided to TEML Westspur to be disseminated and used by TEML Westspur's parents, affiliates, or both, who compete with shippers, such as Crescent Point, in the area.

118 Letter from Sheri Young, Secretary, National Energy Board to Jennifer Geggie et al (26 June 2018) (letter to BP and Enbridge re: the BP complaint) at 4, online: <apps.cer-rec.gc.ca/REGDOCS/File/Download/3580406>.

119 *Tundra Energy Marketing Limited Westspur Pipelines Limited (TEML Westspur) Complaint by Crescent Point Resources Partnership (Crescent Point)* (9 June 2017), Calgary, National Energy Board RHW-002-2017 (complaint), online: <apps.cer-rec.gc.ca/REGDOCS/File/Download/3290874>.

In its complaint, Crescent Point requested relief by way of an order: (1) requiring TEML Westspur to carry out the process relating to the equalization of crude quality differences in a fair and equitable manner in full compliance with the detailed procedures set forth in the Quality Equalization Steering Committee procedures, and (2) requiring TEML Westspur and TEML to file an inter-affiliate code of conduct consistent with those of other NEB-regulated pipelines.

In response, TEML Westspur asserted that it carries out the process relating to the equalization of crude quality differences in a fair and equitable manner and in full compliance with regulation. Further, TEML Westspur challenged the jurisdiction of the NEB to hear that complaint in respect to the Saskatchewan gathering system, which is provincially regulated.

A hearing order was issued by the NEB on 25 August 2017 to consider the issues raised by Crescent Point.[120] On 5 February 2019, the NEB received a letter from Crescent Point notifying the NEB that the complaint had been resolved through negotiation and execution of a settlement agreement.[121] On the same day, TEML Westspur filed amended Rules and Regulations, the Revised Toll Schedule, and the Code of Conduct.

F. BRITISH COLUMBIA NOISE CONTROL BEST PRACTICES GUIDELINE

In December 2018, the BC Oil and Gas Commission (BCOGC) issued the British Columbia Noise Control Best Practices Guideline.[122] The Guideline "outlines the recommended best practices for noise control of operations associated with wells and facilities in the province of British Columbia under the jurisdiction of the Oil and Gas Activities Act."[123]

The Guideline is intended to help define legal requirements for managing noise from well and facility operations, as set out in British Columbia's *Drilling and Production Regulation*[124] and *Liquefied Natural Gas Facility Regulation*.[125]

Obligations of well and facility permit holders in British Columbia established under the Guideline include:

1. development, implementation, and maintenance of a documented Noise Management Program;[126]

---

120 *Tundra Energy Marketing Limited Westspur Pipelines Limited (TEML Westspur) Complaint by Crescent Point Resources Partnership (Crescent Point)* (30 June 2017), Calgary, National Energy Board RHW-002-2017 (hearing order), online: <apps.cer-rec.gc.ca/REGDOCS/File/Download/3321659>.

121 *Tundra Energy Marketing Limited Westspur Pipelines Limited (TEML Westspur) Complaint by Crescent Point Resources Partnership (Crescent Point)* (30 June 2017), Calgary, National Energy Board RHW-002-2017 (withdrawal of complaint), online:<apps.cer-rec.gc.ca/REGDOCS/File/Download/3754088>.

122 BC Oil and Gas Commission, "British Columbia Noise Control Best Practices Guideline," version 2.1 (Victoria: BCOGC, 2018), online: <www.bcogc.ca/node/11095/download > [Guideline].

123 *Ibid* at 6.

124 BC Reg 282/2010.

125 BC Reg 146/2014.

126 Guideline, *supra* note 122 at 8.

2. implementation of site-specific noise mitigation plans where noise concerns are expressed during the permit application consultation process or during First Nations consultation or where a dwelling is located within 800 meters of a well site;[127]

3. adherence to an acceptable sound level determined in reference to the nearest or most impacted dwelling and calculated by a proscribed formula provided under the Guideline;[128] and

4. compliance with a detailed complaint response procedure.[129]

Adherence to the Guideline will likely require affected permit holders to invest in additional noise mitigation tools and procedures. Permit holders who do not own or know how to operate sophisticated noise monitoring equipment may also be required to engage acoustic specialists to measure and monitor noise levels on-site on an ongoing basis. In addition, the Guideline may impact project timelines in the application and consultation phases, as well as create additional obligations in relation to identified stakeholders.

VI. SIGNIFICANT REGULATORY DECISIONS

A. THE FEDERAL COURT OF APPEAL TMEP DECISION

On 30 August 2018, the Federal Court of Appeal released its decision in *Tsleil-Waututh* quashing the TMEP approval.[130] The project's proponent, Trans Mountain Pipeline ULC (Trans Mountain), applied for approval in December 2013, and the NEB had issued its recommendation to approve the project on 19 May 2016.[131] The Governor in Council subsequently directed the NEB to issue a certificate of public convenience and necessity (CPCN) for the project under the *National Energy Board Act*[132] on 29 November 2016.[133]

Numerous applications by interested parties for judicial review of the NEB's report and the Governor in Council's decision were consolidated under the *Tsleil-Waututh* application and heard all at once by the Federal Court.

The Federal Court of Appeal quashed the decision to issue a CPCN on two grounds:

1. the NEB's decision to exclude the effect of increased marine traffic on the southern resident killer whale in its environmental assessment of the project pursuant to the *Canadian Environmental Assessment Act, 2012*[134] was unreasonable; and

127 *Ibid* at 10.
128 *Ibid* at 12.
129 *Ibid* at 25.
130 *Supra* note 15.
131 Canada, National Energy Board, *National Energy Board Report: Trans Mountain Expansion Project*, Catalogue No OH-001-2014 (Calgary: NEB, 2016).
132 RSC 1985, c N-7 [*NEB Act*].
133 Canada, National Energy Board, *Certificate OC-064* (Calgary: NEB, 2016).
134 SC 2012, c 19, s 52 [*CEAA, 2012*].

2. the federal government failed to adequately discharge its duty to consult Indigenous peoples about the project.

On the same day the Federal Court's decision was released, former Premier Notley pulled Alberta out of the Pan-Canadian Framework[135] and Kinder Morgan Canada Limited's shareholders (Trans Mountain's corporate parent) voted to approve the sale of the TMEP to the Canadian government for $4.5 billion.[136]

On 21 September 2018, the Governor in Council instructed the NEB to reconsider its recommendation, taking into account the effects of project-related marine shipping.[137] Two weeks later, the Government of Canada announced it would be reinitiating its Crown consultations with all 117 Indigenous groups potentially impacted by the project.[138]

The Government of Canada reinitiated Phase III consultations in a process led by the Honourable Frank Iacobucci.[139] The process is to include more people, more experts, more funding, more transparency, and mandatory discussion of accommodations.

On 22 February 2019, the NEB released its Reconsideration Report, finding that the TMEP is in the public interest and recommending again that the project be approved and a CPCN issued.[140] The report concluded that the effects on the southern resident killer whales and the increase in GHG emissions were significant, but still found the project to be in the best interest of Canadians on the whole.[141]

In the end, the report included 156 conditions and 16 recommendations

> related to Project-related marine shipping, including: cumulative effects management for the Salish Sea, measures to offset increased underwater noise and increased strike risk posted to SARA-listed marine mammal and fish species, marine oil spill response, marine shipping and small vessel safety, reduction of GHG emissions from marine vessels, and the Indigenous Advisory and Monitoring Committee for the Project.[142]

The Governor in Council must now decide whether to again direct the issuance of a CPCN for the project, this time having regard to the information and conditions in the Reconsideration Report and the additional Phase III consultations.

---

135 *Supra* note 12.

136 Kinder Morgan Canada Limited, News Release, "Shareholders Vote to Approve Sale of Trans Mountain Pipeline and Expansion Project" (30 August 2018), online: <ir.kindermorgancanadalimited.com/2018-08-30-Kinder-Morgan-Canada-Limited-Shareholders-Vote-to-Approve-Sale-of-Trans-Mountain-Pipeline-and-Expansion-Project>.

137 PC 2018-1177, (2018) C Gaz I, 3274.

138 Canada, Major Projects Management Office, "Trans Mountain Expansion Project," online: <mpmo.gc.ca/measures/256>.

139 *Ibid*.

140 National Energy Board, "Reconsideration Report – Trans Mountain Expansion Project," online: <cer-rec.gc.ca/pplctnflng/mjrpp/trnsmntnxpnsn/trnsmntnxpnsnrprt-eng.html>.

141 National Energy Board, News Release, "NEB releases Reconsideration report for Trans Mountain Expansion Project" (22 February 2019), online: <cer-rec.gc.ca/bts/nws/nr/2019/nr04-eng.html>.

142 *Ibid*.

B. COASTAL GASLINK JURISDICTIONAL DISPUTE

The Coastal GasLink (CGL) pipeline is intended to be the sole natural gas supply line for the LNG Canada facility in Kitimat, British Columbia. The pipeline is currently owned by Coastal GasLink Pipeline Ltd., a subsidiary of TransCanada, while the liquified natural gas (LNG) facility is owned by the LNG Canada joint venture, which participants include Shell Canada Energy, North Montney LNG Limited partnership, Diamond LNG Canada Partnership, PetroChina Kitimat LNG Partnership, and Kogas Canada LNG Ltd. The joint venture participants have considerable primary gas resources of their own to supply the LNG facility, and a connection with the NGTL System is contemplated as one of various sources of natural gas for the LNG facility.[143]

The CGL pipeline, which is wholly contained within the province of British Columbia, had received all necessary approvals from the BCOGC by May 2016. In October 2018, the joint venture participants issued a positive final investment decision for the LNG Canada facility, and simultaneously directed Coastal GasLink Pipeline Ltd. to proceed with construction of the pipeline.[144] The project is now in the early phases of construction.

Michael Sawyer, a British Columbia resident, applied to the NEB for an order that CGL was properly under federal jurisdiction on the basis of its potential connection with the interprovincial NGTL System.[145] That connection, he submitted, would make CGL part of a federal undertaking under section 91(10)(a) of the *Constitution Act, 1867*.[146]

Sawyer's CGL application came in the wake of the Federal Court of Appeal decision in *Sawyer v. TransCanada Pipeline Ltd.*, which overturned a preliminary decision of the NEB refusing to consider whether the Prince Rupert Gas Transmission (PRGT) line might properly be within federal jurisdiction.[147] Justice Rennie for the Federal Court of Appeal found that a prima facie case for federal jurisdiction did exist.[148]

Given the recent Federal Court of Appeal precedent and ostensibly similar facts, the NEB found a prima facie case for federal jurisdiction over CGL and ordered a hearing be conducted to determine the issue of jurisdiction.[149] Final arguments were made before the NEB on 2–3 May 2019, and the decision is pending.

---

143 *Jurisdiction over the Coastal GasLink Pipeline Project* (15 February 2019), Calgary, National Energy Board MH-053-2018 (additional written evidence - LNG Canada Development Inc), online:<apps.cer-rec.gc.ca/REGDOCS/File/Download/3754120>.

144 Coastal GasLink Pipeline Project, "About Coastal GasLink," online: <coastalgaslink.com/about/the-project/>.

145 *Jurisdiction over the Coastal GasLink Pipeline Project* (30 July 2018), Calgary, National Energy Board MH-053-2018 (application of Michael Sawyer), online: <apps.cer-rec.gc.ca/REGDOCS/File/Download/3593533>.

146 *Supra* note 27, s 91(10)(a).

147 2017 FCA 159 [*Sawyer*].

148 *Ibid*. PRGT was ultimately suspended given the decision that Pacific NorthWest LNG would not be proceeding with the intended interconnecting LNG project near Port Edward, British Columbia (see online: <tcenergy.com/operations/natural-gas/prince-rupert-gas-transmission-project/>).

149 *Jurisdiction over the Coastal GasLink Pipeline Project* (22 October 2018), Calgary, National Energy Board MH-053-2018 (letter from NEB to William J Andrews and Joel Forrest), online:<apps.cer-rec.gc.ca/REGDOCS/File/Download/3644051>.

C. NIPIGON LNG CORPORATION

The NEB recently refused to issue an order to provide facilities and service for a gas pipeline.[150]

Oil pipelines are required to operate as common carriers under section 71(1) of the *NEB Act*.[151] Gas pipelines, on the other hand, are not required to act as common carriers but may be ordered to provide service or facilities under sections 71(2) and (3).[152]

In October 2018, Nipigon LNG Corporation (NLNG) applied to the NEB pursuant to section 71 of the *NEB Act* requesting an order directing TransCanada Pipelines Limited (TransCanada) to provide facilities and service to NLNG.[153] The facilities were to connect NLNG's planned LNG facility to the TransCanada Mainline, and the service requested was firm gas transportation service.

TransCanada was refusing to proceed with the interconnection without written confirmation from the Local Distribution Companies (LDCs) that the facility was not within their franchise areas. It is a requirement of the Mainline Settlement Agreement between the LDCs and TransCanada that TransCanada will not provide service to LDC customers within a franchise area.

NLNG argued that TransCanada's demand was unreasonable, and that the NLNG facility is not in a franchise area. In the course of the hearing, the LDCs confirmed that the project was indeed not within their franchise areas. In its response to the application, TransCanada stated that it would be willing to provide service "in the normal course" of business, which included a backstopping agreement.[154] NLNG maintained its application, nonetheless, asserting that TransCanada would continue to be discriminatory without the section 71 order, and that the project could not proceed unless the order was issued, as it was a requirement for the project financing.

The NEB refused to issue the orders given that TransCanada had committed to proceed with the interconnection. The NEB found that NLNG had not demonstrated that its request for service had been denied (which is a requirement in the *NEB Filing Manual*[155]), or that

---

150 See *Nipigon LNG Corporation (NLNG) Application pursuant to Section 12, Section 13, Section 59, Subsection 71(2), Subsection 71(3) and Part IV of the* National Energy Board Act *(NEB Act) in respect of TransCanada PipeLines Limited (TransCanada) and the TransCanada Mainline pipeline system (the TransCanada Mainline)* (4 December 2018), online: NEB <apps.cer-rec.gc.ca/REGDOCS/File/Download/3718373> [Nipigon Decision].

151 *Supra* note 132, s 71(1).

152 *Ibid*, ss 71(2)–(3).

153 *Nipigon LNG Corporation (NLNG) Application pursuant to Section 12, Section 13, Section 59, Subsection 71(2), Subsection 71(3) and Part IV of the* National Energy Board Act *(NEB Act) in respect of TransCanada PipeLines Limited (TransCanada) and the TransCanada Mainline pipeline system (the TransCanada Mainline)* (12 October 2018), Calgary, National Energy Board (application by Nipigon LNG Corporation), online:<apps.cer-rec.gc.ca/REGDOCS/File/Download/3619344>.

154 *Nipigon LNG Corporation (NLNG) Application pursuant to Section 12, Section 13, Section 59, Subsection 71(2), Subsection 71(3) and Part IV of the* National Energy Board Act *(NEB Act) in respect of TransCanada PipeLines Limited (TransCanada) and the TransCanada Mainline pipeline system (the TransCanada Mainline)* (31 October 2018), Calgary, National Energy Board (comments of TransCanada PipeLines Limited), online:<apps.cer-rec.gc.ca/REGDOCS/File/Download/3644205>.

155 National Energy Board, "Filing Manual," online: <cer-rec.gc.ca/bts/ctrg/gnnb/flngmnl/index-eng.html>.

TransCanada had refused to provide service. The NEB also found that it would be unfair to TransCanada to grant the orders simply because they were a condition precedent to project financing (and NLNG provided no evidence of this), or without a financial backstop.[156]

D. *EMERA BRUNSWICK V. SIERRA SUPPLIES LTD.*

Emera Brunswick Pipeline Company Ltd. (Emera) appealed the decision of a Pipeline Arbitration Committee (PAC) appointed by the Minister of National Resources to determine the amount of compensation payable by Emera to Sierra Supplies Ltd. (Sierra) for an easement granted to Emera by the NEB pursuant to section 104(1) of the *NEB Act*.[157]

At trial, the PAC awarded Sierra compensation of $466,066.23 plus interest. On appeal, Emera requested that the Federal Court set aside the award and remit it back to the PAC for re-determination in accordance with directions of the Court.[158]

The primary issue of contention to be decided was whether it was reasonable for the PAC to give an award for injurious affection.[159] The PAC awarded Sierra $277,055 for injurious affection based on right-of-way and "safety zone" restrictions on a small industrial parcel (ten acres) of land. Emera alleged there was no injurious affection.

The Federal Court dismissed the appeal of the injurious affection award. The Court held that notwithstanding various errors made by the PAC, the award was rationally supported by the evidence in the record and by reasonable findings of the PAC.[160] The usual rights of Sierra with respect to the land where the pipeline was situated were "greatly diminished" when the Order for easement was issued and registered on title.[161]

The Court determined the reasons of the PAC must be taken as a whole in determining whether the decision was reasonable, even if not every single point in its reasoning meets the reasonableness test.

E. *FORT MCKAY FIRST NATION V. PROSPER PETROLEUM LTD.*

On 16 January 2019, the Alberta Court of Appeal granted Fort McKay First Nation permission to appeal on a narrow issue of whether the AER committed an error of law or jurisdiction by "failing to consider the honor of the Crown" and, as a result, failing to delay approval of Prosper Petroleum Ltd.'s steam-assisted gravity drainage project (the Rigel

---

156 For more information, see the Nipigon Decision, *supra* note 150.

157 A decision, order, or direction of a PAC may be appealed directly to the Federal Court on a question of law or jurisdiction under section 101 of the *NEB Act*, *supra* note 132.

158 *Emera Brunswick Pipeline Co v Sierra Supplies Ltd*, 2018 FC 17 [*Emera Brunswick*].

159 Section 75 of the *NEB Act* provides that a company shall "make full compensation in the manner provided in this Act"; paragraph 97(1)(d) of the *NEB Act* provides that compensation shall be provided for "the adverse effect of the taking of the lands by the company on the remaining lands of an owner." This is the concept of injurious affection.

160 *Emera Brunswick*, *supra* note 158 at para 11.

161 *Ibid* at para 101.

Project) until the First Nation's negotiations with Alberta about the Moose Lake Access Management Program (MLAMP) was complete.[162]

The Rigel Project, a proposed bitumen recovery scheme using SAGD technology, is anticipated to produce 10,000 bpd of bitumen and would operate within ten kilometres of two First Nations' reserves.[163] The Fort McKay First Nation previously entered into a letter of intent with the Government of Alberta to develop an access management plan for the affected area, referred to as MLAMP.

Despite the letter of intent to develop the MLAMP, on 12 June 2018, the AER approved Prosper Petroleum Ltd.'s application for the Rigel Project. In its decision, the AER held that consideration of the MLAMP was not within the panel's mandate and therefore, not part of the scope of the proceeding.[164] Fort McKay sought leave to appeal the AER's decision.

Fort McKay First Nation's argument with respect to this issue was summarized by the Alberta Court of Appeal as follows:

> The First Nation's position can be distilled down to this point: the Letter of Intent constitutes a constitutional obligation based on the doctrine of the honour of the Crown and to give effect to it, the project approval process must be suspended until the *MLAMP* is implement[ed]. In the First Nation's submission, one of the purposes of the Letter of Intent, and the *MLAMP*, is to mitigate the effect of cumulative oil sands development on the Moose Lake Area.[165]

The Court of Appeal was satisfied that this issue raised a question of law of general importance and, therefore, met the test for permission to appeal.

F. NEB DECISION MH-031-2017, NOVA GAS TRANSMISSION LTD. – NORTH MONTNEY MAINLINE VARIANCE AND SUNSET CLAUSE EXTENSION APPLICATION

In May 2018, the NEB granted the variance application of NOVA Gas Transmission Ltd. (NGTL) in respect of the North Montney Mainline (NMML). NGTL requested variances to Condition 4 of the original certificate and order for the NMML project to enable NGTL to proceed with specific components of the NMML independent of any final investment decision related to LNG exports from the west coast of Canada.

The original NMML project approval was conditioned on a final investment decision being made in respect to a proposed LNG liquefication and export facility referred to as the Pacific Northwest LNG Project (PNW LNG Facility).

The NEB evaluated the new facts and changed circumstances described by NGTL, which occurred following the issuance of the original NMML project approval and determined there

---

162 *Fort McKay First Nation v Proposer Petroleum Ltd*, 2019 ABCA 14 at para 32 [*Fort McKay*].

163 *Re Prosper Petroleum Ltd Rigel Project* (12 June 2018), 2018 ABAER 005, online: AER <aer.ca/documents/decisions/2018/2018-ABAER-005.pdf>.

164 *Ibid* at para 10.

165 *Fort McKay*, *supra* note 162 at para 30.

continued to be a need for the NMML facilities. NGTL's variance application was granted, subject to a denial of rolled-in tolling. The question of toll methodology on the NMML is now the subject of the NGTL rate redesign application currently before the NEB.[166]

G. PROVOST RELIABILITY UPGRADE PROJECT

The AUC recently released its decision approving the Provost Reliability Upgrade Project. The decision contained a dissent by AUC Vice-Chair Michaud on the narrow issue of whether the AESO must undertake its own examination of the need for project development. Vice-Chair Michaud found the AESO must consider whether a project is needed *at all*, rather than only an analysis of the alternatives assessed by the proponent (in this case, FortisAlberta Inc.). However, she left the context of the analysis up to the AESO's discretion. Vice-Chair Michaud would have referred the application back to the AESO to consider the relative costs and benefits of the project, as well as the rationale for determining whether the project is required to meet the needs of Albertans.[167]

H. *REFERENCE RE ENVIRONMENTAL MANAGEMENT ACT (BRITISH COLUMBIA)*

On 24 May 2019, the British Columbia Court of Appeal unanimously decided that the proposed amendments to the British Columbia *Environmental Management Act* were unconstitutional.[168] The amendments would have allowed British Columbia to regulate the transportation of heavy oil through the province, including heavy crude and diluted bitumen.

The Court found that the purpose and effect of the proposed amendments was to regulate interprovincial undertakings such as the TMEP. Interprovincial undertakings are subject to federal authority under the Constitution; therefore, the amendments were outside provincial jurisdiction.[169] The Court reaffirmed the power of the federal regulator to consider interests and concerns beyond those of the individual provinces.

VII. LEGISLATIVE DEVELOPMENTS

A. PROTECTIVE LEGISLATION

1. ALBERTA'S *PRESERVING CANADA'S ECONOMIC PROSPERITY ACT*

In early 2018, the government of British Columbia submitted a reference question to its Court of Appeal seeking affirmation of its alleged right to "protect B.C. from the threat of

166 *NOVA Gas Transmission Ltd. - NGTL System Rate Design and Services Application* (March 2019), Calgary, National Energy Board (application), online: <apps.cer-rec.gc.ca/REGDOCS/File/Download/3755733>.

167 *Provost Reliability Upgrade Project* (22 January 2019), 23339-D01-2019, online: AUC <auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/23339-D01-2019.pdf>.

168 *Reference re Environmental Management Act (British Columbia)*, 2019 BCCA 181.

169 *Constitution Act, 1867*, *supra* note 27, s 92(10).

a diluted bitumen spill."[170] The reference dealt with proposed amendments to the *Environmental Management Act* that would allow British Columbia to impact federal project approvals, such as the TMEP.[171]

In response, on 16 May 2018, the Alberta legislature passed Bill 12, *Preserving Canada's Economic Prosperity Act*.[172] It is professed to be an act of the Alberta government to "defend its energy industry" and ensure economic growth, specifically in response to actions by the British Columbia government to delay pipeline construction (specifically, the TMEP).[173]

The *PCEPA* gives the Alberta government authority to require and issue export licences for energy products (for example, natural gas, crude oil, and refined fuels) being exported by pipeline, rail, or truck. It does not apply to crude bitumen or diluted bitumen, and energy product imports are not currently subject to restrictions. Failure to comply with the restrictions could result in fines of up to $10 million per day for a corporation, and the Minister has the authority to issue an order directing an operator to cease transporting natural gas, crude oil, or refined fuels.

British Columbia quickly challenged the constitutionality of Bill 12 in a lawsuit in the Alberta Court of Queen's Bench. Justice Hall dismissed the application in a decision released on 22 February 2019, finding it was premature to challenge a law that was not yet proclaimed.[174] However, he specifically stated that should the Alberta Government proclaim the *PCEPA* in force, British Columbia could recommence its claim.[175] On 1 May 2019, the *PCEPA* was proclaimed in force by Alberta's new provincial government.[176]

2. SASKATCHEWAN *ENERGY EXPORT ACT*

Saskatchewan introduced a similar piece of legislation to Alberta's Bill 12 in April of 2018. Bill 126, *An Act respecting Energy Exports*, received Royal Assent on 23 May 2018.[177] The provisions and purpose of the Act mirrored Alberta's version. However, the Bill passed its legislated expiration date on 31 January 2019 without ever coming into force.

B. OIL PRODUCTION CURTAILMENT

In response to depressed Western Canada Sedimentary Basin oil prices and reduced storage capacity, former Premier Notley announced on 2 December 2018 that the

---

170 Government of British Columbia, News Release, "Province Submits Court Reference to Protect B.C.'s Coast" (26 April 2018), online: <news.gov.bc.ca/16948>, referencing *Reference re: Proposed Amendments to the Environmental Management Act* (18-22 March 2019), Victoria CA45253 (BCCA). See the linked Order in Council and Reference Question Backgrounder for the language of the proposed amendments.

171 The initial British Columbia reference has now been heard, although a decision has not yet been released.

172 Bill 12, *Preserving Canada's Economic Prosperity Act*, 4th Sess, 29th Leg, Alberta, 2018 [*PCEPA*].

173 Government of Alberta, "Preserving Canada's Economic Prosperity," online: <alberta.ca/release.cfm?xID=5577521DB8331-DC67-2CA2-BA443B43F804E3A4>.

174 *British Columbia (Attorney General) v Alberta (Attorney General)*, 2019 ABQB 121.

175 *Ibid* at para 23.

176 Jason Kenney, "Premier Jason Kenney to British Columbians: 'We Will Never Be Afraid to Stand Up for Alberta,'" *Vancouver Sun* (1 May 2019), online: <vancouversun.com/opinion/op-ed/premier-jason-kenney-we-will-never-be-afraid-to-stand-up-for-alberta>.

177 Bill 126, *An Act respecting Energy Exports*, 2nd Sess, 28th Leg, Saskatchewan, 2018.

Government of Alberta would be mandating a temporary reduction of 8.7 percent, or 325,000 bdp, in the province's conventional crude and oil sands production.[178]

On the following day, 3 December 2018, an Order in Council creating the new *Curtailment Rules* regulation was issued.[179] The Order in Council was filed under the *Regulations Act*[180] as a new regulation under the *Oil and Gas Conservation Act*,[181] the *Oil Sands Conservation Act*,[182] and the *REDA*.[183]

The purpose of the *Curtailment Rules* is to effect conservation and prevent wasteful operations, prevent improvident disposition, and ensure the economical development in the public interest of the crude bitumen and crude oil resources of Alberta.[184] It involves reductions at the operator[185] level to combined crude oil and crude bitumen production (as defined in the *OGCA* and *OSCA* respectively), with an exemption for the first 10,000 bpd per operator (effectively exempting operators with outputs less than 10,000 bpd).[186]

The reduction took effect 1 January 2019, with the production limit set at 3.56 million bpd. After the curtailment was announced, storage levels dropped faster than the government expected, reducing the storage glut to approximately 30 million barrels.[187] In response, the Alberta government increased the production limit by 75,000 bpd in February 2019. In April, the limit increased once again by 50,000 bpd to 3.66 million bpd, and to 3.71 million bpd in May.[188] The *Curtailment Rules* will be automatically repealed on 31 December 2019.[189]

The *Curtailment Rules* were also quickly revised to change the formula for calculating each operator's baseline (from which their mandated reduction is measured). As of February 2019, each company's baseline production level is based on its highest level of production during its best single month from November 2017 to October 2018. This is a change from the original formula where the baseline was established on a company's highest six-month average over the same time period.[190]

C. UPDATE ON PROPOSED FEDERAL LEGISLATION

Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*, was adopted by the House of Commons on 20 June 2018, and by the Senate on

---

178 Government of Alberta, News Release, "Premier Acts to Protect Value of Alberta's Resources" (2 December 2018), online: <alberta.ca/release.cfm?xID=621526E3935AA-08A2-6F45-72145AEBDF 115BDF>.

179 *Curtailment Rules*, Alta Reg 214/2018.

180 RSA 2000, c R-14.

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

182 RSA 2000, c O-7 [*OSCA*].

183 *REDA*, *supra* note 49.

184 *Curtailment Rules, supra* note 179, s 2.

185 An "operator" is the holder of an approval under section 1(1)(o) of the *OSCA*, *supra* note 181.

186 *Curtailment Rules*, *supra* note 179.

187 Emily Mertz, "Alberta Eases Oil Production Cap by 75K Barrels per Day," *Global News* (30 January 2019), online: <globalnews.ca/news/4907488/alberta-oil-production-cap-curtailment-change-notley/>.

188 Government of Alberta, "Oil Production Limit," online: <alberta.ca/oil-production-limit.aspx>.

189 *Curtailment Rules*, *supra* note 179, s 10.

190 See OC 375/2018, amended by Alta Reg 16/2019.

12 December 2018.[191] The Bill was then referred to a Senate Committee (the Standing Senate Committee on Energy, the Environment and Natural Resources), which toured the country to hear from interested parties in different jurisdictions.[192] Amendment recommendations have been released and are under consideration by the Senate.[193]

Bill C-68, *An Act to amend the Fisheries Act and other Acts in consequence* is also in its second reading in the Senate and has been referred to the Standing Senate Committee on Fisheries and Oceans.[194]

Bill C-48, *An Act respecting the regulation of vessels that transport crude oil or persistent oil to or from ports or marine installations located along British Columbia's north coast* (short title, the *Oil Tanker Moratorium Act*) is in its second reading in the Senate and has been referred to the Standing Senate Committee on Transport and Communications. Still very much in dispute, on 14 May 2019, Transport Minister Marc Garneau told the Senate committee that he is open to amendments to the Bill, however, only those that would maintain the ultimate purpose of a moratorium on crude oil shipments from British Columbia's northern coast.[195]

D. CHANGES TO BRITISH COLUMBIA'S ENVIRONMENTAL ASSESSMENT PROCESS

On 26 November 2018, Bill 51, *Environmental Assessment Act* passed in the British Columbia legislature.[196] Bill 51 is intended to "revitalize" the environmental assessment (EA) regime and ultimately replace the *Environmental Assessment Act*.[197] A number of policies and regulations must be developed before the bill comes into force.

Bill 51 proposes a dramatic modification in the project approval process in British Columbia. The primary objectives of the changes are set out in an Intentions Paper, published by the Province of British Columbia, which include:

1. enhancing public confidence, transparency, and meaningful participation;

2. advancing reconciliation with Indigenous groups; and

---

191 Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*, 1st Sess, 42nd Parl, 2018 (second reading 12 December 2018). The controversial new legislation proposed to be enacted by Bill C-69 includes the *Canadian Energy Regulator Act* (*CERA*) and the *Impact Assessment Act* (*IAA*). The *CERA* would replace the NEB with the Canadian Energy Regulator and the *IAA* would replace the Canadian Environmental Assessment Agency with the Impact Assessment Agency.

192 See Parliament of Canada, "House Government Bill: C-69," online: <parl.ca/LegisInfo/BillDetails.aspx?billId=9630600&Language=E> for a review of the status of Bill C-69.

193 The proposed amendments are contained in the briefs submitted to the Standing Committee and are available on the Senate of Canada website, online: <sencanada.ca/en/committees/ENEV/Briefs/42-1?oor_id=499144>.

194 See Parliament of Canada, "House Government Bill: C-68," online: <parl.ca/LegisInfo/BillDetails.aspx?Language=E&billId=9630814> for a review of the status of Bill C-68.

195 For transcripts of the Senate Committee on Transportation and Communications, see online: <sencanada. ca/en/Committees/trcm/TranscriptsMinutes/42-1>.

196 Bill 51, *Environmental Assessment Act*, 3rd Sess, 41st Parl, British Columbia, 2018 (third reading 26 November 2018), online: <www.leg.bc.ca/parliamentary-business/legislation-debates-proceedings/41st-parliament/3rd-session/ bills/third-reading/gov51-3> [Bill 51].

197 SBC 2002, c 43.

3. protecting the environment while offering clear pathways to sustainable project approvals.[198]

Key changes to the EA process as proposed in Bill 51 include:

- an early engagement phase to identify interests, issues, and concerns of Indigenous nations, stakeholders, and the public that can inform project design, siting and alternative approaches to developing the project and which will determine whether a project can proceed with an EA;[199]

- two distinct decision points at which Indigenous nations may confirm their consent or lack of consent to a decision by the regulator;[200]

- multiple decision points at which the regulator must "seek to achieve consensus" with Indigenous nations,[201] with a dispute resolution process to be established through subsequent regulation where consensus is not achieved;[202]

- enhanced public participation through public comment periods and engagement tools; and[203]

- addition of a non-exhaustive list of factors that must be considered in every EA.[204]

This "consent-based" EA model is intended to foster reconciliation and contribute to the implementation of the *United Nations Declaration on the Rights of Indigenous Peoples*.[205]

Bill 51 is anticipated to come into force in late 2019.

E. REGULATORY IMPLICATIONS OF REDWATER

On 31 January 2019, the Supreme Court of Canada released its decision in *Orphan Well Association v. Grant Thornton Ltd*.[206] In a split 5-2 decision, the majority ruled there is no operational conflict between the reclamation and abandonment provisions of the Alberta oil and gas regulatory regime and the *Bankruptcy and Insolvency Act*.[207]

The majority further held that section 14.06(4) of the *BIA* "does not empower a trustee to walk away from all responsibilities, obligations and liabilities with respect to 'disclaimed'

---

198 Government of British Columbia, "Environmental Assessment Revitalization Intentions Paper" (Victoria: Government of British Columbia, 2018) at 3, online: <www2.gov.bc.ca/assets/gov/environment/natural-resource-stewardship/environmental-assessments/environmental-assessment-revitalization/documents/ea_revitalization_intentions_paper.pdf>.

199 Bill 51, *supra* note 196, Part 4.

200 *Ibid*, ss 16, 29.

201 *Ibid*, ss 16, 19, 27–29, 31–32, 34–35, 73.

202 *Ibid*, s 5.

203 *Ibid*, s 23.

204 *Ibid*, s 25.

205 *United Nations Declaration on the Rights of Indigenous Peoples*, GA Res 61/295, UNGAOR, 61st Sess, Supp No 53, UN Doc A/61/53 (2007) [*UNDRIP*].

206 2019 SCC 5 [*Orphan Wells*].

207 *Orphan Wells*, *ibid* at para 162; RSC 1985, c B-3 [*BIA*].

assets. Rather, it clarifies a trustee's protection from environmental personal liability and makes it clear that a trustee's 'disclaimer' does not affect the environmental liability of the bankrupt estate."[208]

The AER has publicly stated that it is reviewing the decision and its implications and is expected to make consequential changes to its regulatory processes and requirements governing oil and gas well and facility end-of-life obligations.[209] In the meantime, the AER has recognized its "responsibility to uphold the Supreme Court of Canada's ruling that financial matters do not have priority over environmental responsibilities."[210]

F. *UNDRIP* AND BILL C-262

UNDRIP declares the human rights of Indigenous peoples (for example, rights specifically construed in relation to the colonial history and situation of Indigenous peoples worldwide) and the duties of states in effecting those rights.

Canada endorsed *UNDRIP* in May 2016; however, it has not, to date, been enacted into law through legislation.

Bill C-262, *An Act to ensure that the laws of Canada are in harmony with the United Nations Declaration on the Rights of Indigenous Peoples* is a private member's bill which was introduced on 21 April 2016, supported by the Liberals and NDP. Bill C-262 would support the implementation of *UNDRIP* into Canadian law. The Bill was adopted by the House of Commons on 30 May 2018 and, at the time of writing, was before the Senate at second reading.

Bill C-262 does not purport to make *UNDRIP* law itself, but explicitly recognizes the principles of *UNDRIP* and sets out an intention on behalf of Canada to achieve "the ends" of *UNDRIP* and see it is made effective; "the intent of the Bill is to establish the Declaration as a standard against which to measure Canadian laws and to bring those laws into conformity with the Declaration over a period of time. It is not the intent of the Bill to make the Declaration law."[211]

VIII. ENVIRONMENTAL

A. *SPECIES AT RISK ACT*

Le Groupe Maison Candiac Inc. v. Canada (AG)[212] involved an application for judicial review regarding the emergency order for the western chorus frog, issued by the federal

---

208 *Orphan Wells*, *ibid* at para 102.

209 Alberta Energy Regulator, Public Statement, "Alberta Energy Regulator Pleased with Supreme Court of Canada Redwater Decision" (31 January 2019), online: <aer.ca/providing-information/news-and-resources/news-and-announcements/news-releases/public-statement-2019-01-31>.

210 See Alberta Energy Regulator, News Release, "Alberta Energy Regulator Responding to Ceased Operations at Trident Exploration" (1 May 2019), online: <aer.ca/providing-information/news-and-resources/news-and-announcements/news-releases/news-release-2019-05-01>.

211 Nigel Bankes, "Implementing UNDRIP: Some Reflections on Bill C-262" (27 November 2018), online (blog): <ablawg.ca/ 2018/11/27/implementing-undrip-some-reflections-on-bill-c-262/>.

212 2018 FC 643.

cabinet under the *Species at Risk Act*.[213] An affected developer asserted the provision of *SARA* that allows emergency orders to impose restrictions on activities on private land is unconstitutional.

The Federal Court upheld the order under section 91(27) of the *Constitution Act, 1867* because it aimed to suppress an evil accompanied by a sanction and served a legitimate public purpose (for example, to protect against an imminent threat, caused by human activity, to the survival or recovery of a species at risk).

This decision provides a basis for other emergency or "safety net" orders to be issued protecting the critical habitat of other *SARA* species (such as killer whales and mountain or boreal caribou).

213 SC 2002, c 29 [*SARA*].

[*this page is intentionally blank*]