RECENT REGULATORY AND LEGISLATIVE DEVELOPMENTS OF INTEREST TO ENERGY LAWYERS

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This article discusses recent developments in the regulatory and legislative spheres of interest to energy lawyers. The authors reviewed regulatory initiatives, decisions, related case law and legislation from provincial, territorial, and federal authorities. Topics of note include hydraulic fracturing, oil by rail, liquefied natural gas, renewable energy and power, the new Alberta Energy Regulator, oil and gas development, environmental protection, and Aboriginal and other issues. The period covered is May 2013 to April 2014, inclusive.

Cet article porte sur les récents développements dans les milieux réglementaires et législatifs d'intérêt pour les avocats travaillant dans le domaine de l'énergie. Les auteurs ont examiné les initiatives réglementaires, les décisions, la jurisprudence pertinente et la législation provinciale, territoriale et fédérale. Les sujets d'intérêt comprennent la fracturation hydraulique, le transport du pétrole par chemin de fer, le gaz naturel liquéfié, l'énergie renouvelable, le nouveau régulateur de l'Alberta, le développement des secteurs pétrolier et gazier, la protection de l'environnement, les Autochtones et autres questions. L'article couvre la période de mai 2013 à avril 2014, inclusivement.

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I. INTRODUCTION

This has been a significant year for the practice of energy law in Canada. Hydraulic fracturing has become both a national and international issue. The Lac-Mégantic crisis brought increased focus to oil-by-rail in Canada and the United States. In Alberta, the new Alberta Energy Regulator has released its first regulatory decisions, giving lawyers insight into the workings of the tribunal. While final regulatory decisions have been reached for many large projects across Canada, many others, including the Keystone XL and Northern Gateway pipelines, continue to face hurdles to completion.

The purpose of this article is to canvass decisions and legislative developments of interest to energy lawyers that occurred since the last review. This article is divided into ten sections. Within each section, the relevant legislative developments and important regulatory and court decisions are discussed.

II. HYDRAULIC FRACTURING

A. FEDERAL

1. NATIONAL ENERGY BOARD

i. *Filing Requirements for Onshore Drilling Operations Involving Hydraulic Fracturing*

Prior to the coming into force of the *Northwest Territories Devolution Act*[1] on 1 April 2014 (discussed further in Part X.D.1, below), the National Energy Board (NEB) was responsible for approving all oil and gas projects in the Northwest Territories under the *Canada Oil and Gas Operations Act*.[2] Until relatively recently, the *COGOA* and its relevant regulations, contained no guidance on the criteria the NEB would use to approve hydraulic fracturing, or "fracking," projects. However, on 12 September 2013, the NEB released its *Filing Requirements for Onshore Drilling Operations Involving Hydraulic Fracturing*.[3]

The stated purpose of the *Filing Requirements* is to "outline the information the [NEB] will need to assess future applications for drilling that involve hydraulic fracturing."[4] There are three major criteria under the *Filing Requirements*:

(1) requirements proponents must meet to conform to environmental assessment standards (conducted between the NEB and various territorial boards);

(2) requirements to be met in order to be issued an operating licence to conduct hydraulic fracturing activities; and

(3) requirements to obtain a well approval for drilling an oil well.

While the *Filing Requirements* are not fully prescriptive, the following decision demonstrates that operators can still expect a significant degree of regulatory oversight.

ii. ConocoPhillips Hydraulic Fracturing Approval in the Northwest Territories

The timing of the release of the *Filing Requirements* also coincides with the NEB's first approval of fracking operations in the Northwest Territories, where the NEB gave ConocoPhillips permission to drill and hydraulically fracture two wells near Tulita.[5]

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1 SC 2014, c 2 [*Devolution Act*].
2 RSC 1985, c O-7 [*COGOA*].
3 National Energy Board, *Filing Requirements for Onshore Drilling Operations Involving Hydraulic Fracturing September 2013*, (Calgary, National Energy Board, 2013), online: National Energy Board <www.neb-one.gc.ca/bts/ctrg/gnthr/flrqnshrdrllprtn/flrqnshrdrllprtn-eng.pdf> [*Filing Requirements*].
4 *Ibid* at 2.
5 "NEB OK's 1st fracking project in N.W.T.," *CBC News* (30 October 2013), online: CBC News <www.cbc.ca/news/canada/north/neb-ok-s-1st-fracking-project-in-n-w-t-1.2288935>.

ConocoPhillips had applied for an Operations Authorization (in this section, an OA) to undertake an exploration drilling program in the Northwest Territories over a period of five years. The NEB was satisfied with ConocoPhillips' risk assessment and proposed mitigation measures and granted the application.[6] It attached six conditions to the OA, whereby the proponent must:

(1) request approval for any deviations from the authorized program;

(2) implement all of its proposed mitigation, safety, and environmental protection measures;

(3) file updated operator contact information prior to any activity;

(4) file an updated environmental protection plan 30 days prior to the start of any operations requiring a Well Approval;

(5) file with the NEB a copy of the water well monitoring report it is required to submit to the Sahtu Land and Water Board; and

(6) keep a record of suspected seismic events and report the consolidated information in its annual safety report. The proponent must also immediately report any disruption of its operations resulting from a suspected seismic event.[7]

iii. *COGOA* Hydraulic Fracturing Fluids Disclosure Request

On 4 February 2014, the NEB requested through its website that any operator regulated under *COGOA* submit information on the composition of fluids used for hydraulic fracturing operations within 30 days of the completion of a hydraulic fracturing operation. The NEB asked operators to submit a Fluid Component Record (in this section, a Record) for each well where hydraulic fracturing was conducted, which includes disclosure of information such as the trade name and purpose of the fluid, the supplier of the fluid, and the chemical ingredients of the fluid. The NEB can also ask the operator to resubmit the Record in another format to allow for fuller disclosure of hydraulic fracturing fluid chemicals.

Guidelines for completing a Record, along with a model form, are posted on the NEB website.[8]

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6 National Energy Board, *Operations Authorization (OA) for ConocoPhillips Canada Resources Corp. (ConocoPhillips) 2013 EL 470 Exploration Drilling Program in the Tulita Area, NWT* (30 October 2013), online: NEB <www.neb-one.gc.ca/nrth/dcsns/2013-10-30cncphllps-eng.pdf> [*ConocoPhillips*].

7 *Ibid* at 3.

8 "National Energy Board Procedure for the Public Disclosure of Hydraulic Fracturing Fluid Composition Information" (4 February 2014), online: NEB <www.neb-one.gc.ca/bts/ctrg/gnthr/cndlgsprtnct/hdrlcfrctrng/dsclsrhdrlcfrctrng-eng.html>.

After a Record is submitted, it will be disclosed to the public on the Fracfocus.ca website.[9] Additionally, if any information relating to a well is subject to the privilege provisions in sections 101(7)(a) to (c) of the *Canada Petroleum Resources Act*,[10] operators are asked to waive that privilege and consent to public disclosure.

2. COURT ACTIONS

i. *Lone Pine Resources Inc. v. Government of Canada*

The claim brought by Lone Pine Resources Inc. (Lone Pine) under chapter 11 of *NAFTA*[11] against the Government of Canada appears to be on its way to binding arbitration.[12] From 2006 to 2011, Lone Pine had attempted to obtain permits and approvals from the Government of Quebec to explore for oil and gas beneath the St. Lawrence River. In 2011, however, their progress was stymied by the Government of Quebec's revocation of all permits for oil and gas resources in and around the St. Lawrence River area.

Lone Pine's claim was brought under articles 1105 and 1110 of *NAFTA*.[13] In particular, Lone Pine claims that the Government of Quebec expropriated its valuable property without a public purpose, due process, or payment of compensation. On 6 September 2013, Lone Pine, in respect of a subsidiary, Lone Pine Resources Canada Ltd., gave notice to the Government of Canada that it intended to proceed with the dispute by way of binding arbitration. Lone Pine is seeking at least $250 million in damages.[14]

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9 Pursuant to a 2 November 2013 agreement among the NEB, the British Columbia Oil and Gas Commission and the US-based Ground Water Protection Council and Interstate Oil and Gas Compact Commission, the NEB agreed to participate in the website: "National Energy Board to Join FracFocus.ca" (27 November 2013), online: NEB <www.neb-one.gc.ca/bts/nws/nr/2013/nr32-eng.html.>.

10 RSC 1985, c 36 (2d Supp), ss 101(7)(a)-(c).

11 *North American Free Trade Agreement Between the Government of Canada, the Government of Mexico and the Government of the United States*, 17 December 1992, Can TS 1994 No 2, 32 ILM 289 (entered into force 1 January 1994) [*NAFTA*].

12 "NAFTA – Chapter 11 – Investments: Cases Filed Against the Government of Canada," online: Foreign Affairs, Trade and Development Canada <www.international.gc.ca/trade-agreements-accords-commerciaux/topics-domaines/disp-diff/lone.aspx?lang=eng>.

13 *Lone Pine Resources Inc v Government of Canada* (Notice of Intent to Submit a Claim to Arbitration Under Chapter Eleven of the North American Free Trade Agreement, 8 November 2012 at para 5), online: Foreign Affairs, Trade and Development Canada <www.international.gc.ca/trade-agreements-accords-commerciaux/topics-domaines/disp-diff/lone.aspx?lang=eng>.

14 *Lone Pine Resources Inc v Government of Canada* (Notice of Arbitration Under the Arbitration Rules of the United Nations Commission of International Trade Law and Chapter Eleven of the North American Free Trade Agreement, 6 September 2013), online: Foreign Affairs, Trade and Development Canada <www.international.gc.ca/trade-agreements-accords-commerciaux/assets/pdfs/disp-diff/lone-02.pdf>.

B. BRITISH COLUMBIA

1. COURT ACTIONS

i. *Western Canada Wilderness Committee and Sierra Club of British Columbia Foundation v. Oil and Gas Commission and Encana Corporation*[15]

On 13 November 2013, two Canadian environmental groups filed a lawsuit against the British Columbia Oil and Gas Commission (OGC) and Encana Corporation (Encana). The lawsuit seeks to quash specific approvals granted to Encana by the OGC under section 8 of the provincial *Water Act*.[16] In the pleadings, the plaintiffs both express concern that "significant quantities of fresh water are being used and diverted…for hydraulic fracturing" and formally claim that the OGC's practice of granting multiple short term approvals for the use or diversion of water contravenes section 8 of the *Water Act*.[17]

Specifically, the plaintiffs argue that, as the *Water Act* requires a party to obtain a water licence if the use or diversion of water is required for more than one term or for more than 24 months, "[i]ssuing repeated Section 8 Approvals to the same company, for the same location, for the same purposes is inconsistent with the express language and full context of the *Water Act*."[18] They further claim that the "practice of granting Section 8 Approvals that combine to exceed one term or the statutory time limit has been ongoing for at least seven years and is a systemic practice by the [OGC]."[19]

C. ALBERTA

1. COURT ACTIONS

i. *Ernst v. Encana Corp.*[20]

The plaintiff sued Encana, the Alberta Energy Resources Conservation Board (ERCB) (now the Alberta Energy Regulator), and the Province of Alberta. The claim against Encana was based on "negligence, nuisance, the rule in *Rylands v Fletcher*, and trespass," whereas the claim against the ERCB was in negligence and breach of the *Charter*.[21] Finally, the claim against Alberta was in negligence.

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15 Petition to the Court, Vancouver S-13403 (BCSC) [WCWC Petition].

16 RSBC 1996, c 483.

17 WCWC Petition, *supra* note 15 at 5, 8. This section of the *Water Act* states that, "[i]f diversion or use of water is required for a term not exceeding 24 months, the comptroller or a regional water manager may, on application, without issuing a licence, grant an approval in writing, approving the diversion or use, or both, of the water on the conditions the comptroller or regional water manager considers advisable" (*Water Act*, *supra* note 16, s 8(1)).

18 WCWC Petition, *ibid* at 8.

19 *Ibid* at 7.

20 2013 ABQB 537, 570 AR 317 [*Ernst*].

21 *Ibid* at paras 1-2; *Rylands v Fletcher*, (1868) LR 3 HL 330; *Canadian Charter of Rights and Freedoms*, Part I of the *Constitution Act, 1982*, being Schedule B to the *Canada Act 1982* (UK), 1982, c 11 [*Charter*].

The plaintiff filed her original statement of claim on 3 December 2007. The defendants applied to strike various paragraphs of the claim. Counsel for all parties eventually agreed, at the suggestion of the Court, to permit the plaintiff to re-draft a fresh statement of claim, which was filed in June 2012.

The ERCB as defendant applied to strike certain paragraphs of the fresh claim, or in the alternative for summary judgment. The Province of Alberta as defendant also applied to strike certain paragraphs of the fresh claim, but in the alternative pleaded for better particulars. The third defendant, Encana, did not participate in the application.

The application was heard in January of 2013. Before the decision was released, the *Energy Resources Conservation Act*[22] was repealed, and the *Responsible Energy Development Act*[23] came into force.

The plaintiff's claim against the ERCB in negligence was struck out. Although public bodies such as the ERCB can owe private duties of care, the ERCB in this case owed no private duty of care to the plaintiff. Proximity between a public body and a plaintiff is necessary to establish such a duty, and was absent in this case. The plaintiff's claim against the ERCB for breach of *Charter* rights was also struck. Section 43 of *ERCA* immunized the ERCB from personal, as opposed to public, *Charter* claims.

Finally, the plaintiff's claim against Alberta was not struck. Alberta pleaded for relief under section 3.68 of the *Alberta Rules of Court*.[24] However, the Court held that this section only attacks gibberish or incoherent pleadings and does not apply to strike pleadings that are merely bad.[25]

D. QUEBEC

1. ADMINISTRATIVE PENALTIES UNDER THE *ENVIRONMENT QUALITY ACT*[26]

The Quebec government completed its harmonization of the penal sanctions and administrative penalties to be applied under the *Environment Quality Act* this past summer. The changes were introduced following a mandatory review of Bill 89, *An Act to amend the Environment Quality Act in order to reinforce compliance*.[27] The *EQA Amending Act*, which granted additional compliance powers to Quebec's environmental regulator under the *EQA*, required that the accompanying regulations be revised to account for such new powers no later than 30 June 2013:

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22 RSA 2000, c E-10 [*ERCA*].
23 SA 2012, c R-17.3 [*REDA*].
24 Alta Reg 124/2010.
25 *Ernst*, *supra* note 20 at paras 129-30.
26 CQLR c Q-2 [*EQA*].
27 2nd Sess, 39th Leg, Quebec, 2011 (assented to 5 October 2011), SQ 2011, c 20 [*EQA Amending Act*].

> The Government or the Minster, as applicable, must … in order to harmonize the penal provisions of those regulations with those enacted by this Act, determine the provisions of those regulations that may give rise to a monetary administrative penalty if they are not complied with, define the conditions for applying such a penalty, and set forth the amounts of the penalties or the methods for calculating them, in accordance with this Act.[28]

One of the regulations which was part of the revision process was the *Regulation respecting the filing of information on certain drilling and fracturing work on gas or petroleum wells*.[29] The *Filing Regulation* was amended in July 2013 by adding additional monetary administrative penalties under sections 9.1, 9.2, 10.1 and 10.2.

For the information filing requirements under the *Filing Regulation*, which requires information disclosure from all holders of certificates of authorization under the *EQA* for shale gas drilling and any oil and gas hydraulic fracturing operations, the administrative penalties for minor missed filings or improper record-keeping range from $250 to $350 for natural persons, and $1,000 to $1,500 for other organizations.[30] For more serious errors, such as not having "[i]nformation that is scientific or technical … certified by a person or enterprise that is competent or accredited for that purpose by a recognized authority,"[31] the fines range from $2,000 to $100,000 for natural persons and $6,000 to $600,000 for a corporation.[32] Finally, every person who makes a false or misleading declaration or communication of information, or who files a document that is false or misleading, is liable to a fine of $5,000 to $500,000 or a term of imprisonment not exceeding 18 months, or $15,000 to $3,000,000 for a corporation.[33]

E. NOVA SCOTIA

1. *IMPORTATION OF HYDRAULIC FRACTURING WASTEWATER PROHIBITION ACT*

On 12 December 2013, the *Importation of Hydraulic Fracturing Wastewater Prohibition Act*[34] received Royal Assent in Nova Scotia. Originally Bill 5, it was introduced by the Minister of Environment of Nova Scotia, Randy Delorey just ten days prior. As reported in *The Globe and Mail*, Mr. Delorey considered a ban on accepting waste water from hydraulic fracturing an appropriate response given there was already a moratorium on hydraulic fracturing in place in the province (pending an independent review).[35]

28 *Ibid*, s 61.
29 CQLR c Q-2, r 47.1 [*Filing Regulation*].
30 *Ibid*, ss 9.1, 9.2.
31 *Ibid*, s 7.
32 *Ibid*, s 10.1.
33 *Ibid*, s 10.2.
34 Bill 5, 1st Sess, 62nd Leg, Nova Scotia, 2013 (assented to 12 December 2013), SNS 2013, c 36 [*Wastewater Prohibition Act*].
35 "N.S. introduces bill to ban import of waste water from shale-gas fracking" *The Globe and Mail* (2 December 2013) online: The Globe and Mail <www.theglobeandmail.com/news/politics/ns-introduces-bill-to-ban-import-of-waste-water-from-shale-gas-fracking/article15727342/>.

The *Wastewater Prohibition Act* defines hydraulic fracturing wastewater as "any water used in or produced from hydraulic fracturing or other geological formation stimulation, and includes produced or formation water resulting from wells that have been hydraulically fractured."[36] The prohibition is set out under section 4:

No person shall

(a) import into the Province hydraulic fracturing waste water from outside the Province; or

(b) transport hydraulic fracturing waste water into the Province.[37]

Contravention of the *Wastewater Prohibition Act* or any regulations thereunder is a summary conviction offence under section 5 and carries a fine of not more than $10,000. Where an offence is committed or continued on more than one day, the person who committed the offence is liable for a separate offence for each such day. With respect to the regulations, there is a standard provision establishing the Governor in Council's power to make such regulations considered necessary or advisable to effectively carry out the intent and purpose of the *Wastewater Prohibition Act*.

III. OIL BY RAIL[38]

A. FEDERAL

1. LAC-MÉGANTIC EMERGENCY DIRECTIVE

As part of the federal government's response to the Lac-Mégantic rail disaster that occurred on 6 July 2013, Transport Canada announced an emergency directive in an effort to immediately increase rail safety. This directive, announced on 23 July 2013 and recently renewed for the period from 1 January 2014 until 1 July 2014 in similar form, was issued pursuant to section 33 of the *Railway Safety Act*[39] and requires all railway operators to:

1. Ensure that all unattended controlling locomotives on main track and sidings are protected from unauthorized entry into the cab;

2. Ensure that reversers are removed from any unattended locomotive on main track or sidings. During sub-zero temperatures, this item does not apply to locomotives that do not have a high idle feature;

3. Ensure that their company's special instructions on hand brakes referred to in Rule 112 of the *Canadian Rail Operating Rules* is applied when any locomotive coupled with one or more cars is left unattended for more than one hour on main track or sidings;

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36 *Supra* note 34, s 2(b).
37 *Ibid*, s 4.
38 The authors would like to thank Sara Gilbert of Bennett Jones LLP for her assistance with this section of the article.
39 RSC 1985, c 32.

4. Ensure, when any locomotives coupled with one or more cars is left unattended for one hour or less on main track or sidings, that in addition to complying with their company's special instructions on hand brakes referred to in item 3 above, the locomotives have the automatic brake set in full service position and have the independent brake fully applied;

5. Ensure that no locomotive coupled with one or more loaded tank cars transporting "dangerous goods" … is left unattended on a main track; and

6. Ensure that no locomotive coupled with one or more loaded tanks cars transporting "dangerous goods" … is operated on main track or sidings with fewer than two persons qualified under their company's requirements for operating employees.[40]

The emergency directives are intended to be a temporary solution while the federal government and railway companies develop changes to the legislative regime for the transportation of dangerous goods (as discussed in further detail below) and rules respecting the matters covered by the emergency directive.

2. TRANSPORT CANADA DEVELOPMENTS

In response to the Lac-Mégantic crisis, in November 2013 Transport Canada requested recommendations from three working groups on improving standards for transporting dangerous goods: the Classification Working Group, the Emergency Response Assistance Plan Working Group, and the Means of Containment Working Group (collectively, the Working Groups).[41] The suggestions of the Working Groups were received on 31 January 2014.

The Classification Working Group submitted suggestions based primarily on strengthening the testing and classification framework for crude oil.[42] A key goal was to improve the accuracy of crude testing procedures, and the Working Group advocated using the true vapour pressure test method.[43] It also suggested establishing a clear upper risk threshold, and that Transport Canada institute routine testing procedures and develop criteria for defining toxicity and corrosivity.[44]

The Emergency Response Assistance Plan Working Group recommended that emergency response plans describing specialized procedures for emergency situations involving high risk goods be developed for Class 3 flammable liquids, and that these plans be required when

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40 Gerard McDonald, "Emergency Directive Pursuant to Section 33 of the Railway Safety Act," online: Transport Canada <www.tc.gc.ca/eng/railsafety/emergency-directive-947.html>.

41 "Transportation of Dangerous Goods General Policy Advisory Council," online: Transport Canada <www.tc.gc.ca/eng/tdg/consult-advisorycouncil-488.htm>.

42 GPAC Testing and Classification Working Group, *Strengthening the Testing and Classification Framework for Crude Oil by Rail, January 31, 2014*, online: Transport Canada <www.tc.gc.ca/media/documents/tdg-eng/5806-2014-3479-F-BT8821720-CAPP-EDMS-238982-v1-Jan-31-14-GPAC-Test-C-en-rev-AAA.pdf>.

43 *Ibid* at 4.

44 *Ibid* at 5-9.

the product is shipped in a single tank car.[45] The Means of Containment Working Group's main suggestion was to develop a higher standard for design safety of tank cars, and to include all dangerous goods into the categories of Packing Group I and Packing Group II.[46]

In addition to the submissions of the Working Groups discussed above, Transport Canada also engaged in public consultation to deal with issues of liability and compensation in regards to rail accidents. A discussion paper was written on this issue (the Discussion Paper), which indicated that maximum insurable amounts may have to be increased to adequately deal with disasters such as Lac-Mégantic.[47] Issues put forward in the Discussion Paper include identifying the strengths of the current system and how it can be improved, identifying gaps in the current regime, identifying best practices, identifying key challenges or concerns, allocating risk, determining the extent to which insurance should be available to cover third party liability, allocating cost, and considering the competitiveness of the Canadian railway industry. Submissions on the Discussion Paper were accepted by Transport Canada until 21 March 2014.

3. AMENDMENTS TO THE *TRANSPORTATION OF DANGEROUS GOODS REGULATIONS*

On 11 January 2014, in response to the Lac-Mégantic train derailment and resulting investigation by the Transportation Safety Board of Canada (TSB), the Government of Canada released proposed amendments to the *Transportation of Dangerous Goods Regulations*.[48] The amending regulations were published in the *Canada Gazette*, Part II, on 2 July 2014 and came into effect on 15 July 2014.[49]

The amendments will adopt the new Transport Canada Standard TP14877, which updates certain tank design, selection, and use requirements so as to bring Canadian standards into compliance with the Association of American Railroad (AAR) requirements in the United States. In addition, as highlighted below, the amendments introduce new requirements for consignors and, in certain cases, carriers.

i. Proof of Classification

A new section 2.2.1 has been added that requires a consignor who allows a carrier to take possession of dangerous goods for transport or who imports dangerous goods into Canada

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45 Transportation of Dangerous Goods General Policy Advisory Council (GPAC) Emergency Response Assistance Plan (ERAP) Working Group, *Report and Recommendations Relating to Class 3 Flammable Liquids, January 31, 2014*, online: Transport Canada <www.tc.gc.ca/media/documents/tdg-eng/5807-2014-3477-F-BT8821720-ERAP-WG-Report-and-Recommendations-FINAL-21-en-rev-AAA-rev.pdf> at 13,17.

46 GPAC Means of Containment Working Group, *Means of Containment (DOT 111 tank cars) Recommendations to the Federal Minister of Transport* (31 January 2014), online: Transport Canada <www.tc.gc.ca/media/documents/tdg-eng/5808-2014-3478-F-BT8821720-FINAL1-Recommendation-Document-GPAC-MOC-W-1-en-rev-AAA-rev.pdf> at 14-17.

47 Transport Canada, *Comprehensive Review of the Third Party Liability and Compensation Regime for Rail* (Discussion Paper TP 15242 E), online: Transport Canada <www.tc.gc.ca/media/documents/policy/Discussion-Paper-Compensation-Liability.pdf>.

48 SOR/2001-286 [*TDGR*]. The *TDGR* is issued under the *Transportation of Dangerous Goods Act*, 1992, SC 1992, c 34.

49 SOR/2014-152.

to now keep a "proof of classification"[50] for a period of up to five years from the date appearing on the shipping document. For example, a material safety data sheet (MSDS) is not sufficient proof of classification *unless it is also accompanied* by a document that explains how the dangerous goods were classified.

In the case of crude oil (and certain other liquid petroleum products), classification must also be done on the basis of samples, with an accompanying documented sampling methodology. The documentation provided in respect of the sampling methodology must include:

- the scope of the method;
- the sampling apparatus;
- the sampling procedures;
- the frequency and conditions of sampling; and
- a description of the quality control management system in place.[51]

ii. Consignor's Certification

Section 3.6.1 was also added and requires a consignor, or an individual acting on behalf of the consignor, to complete a certification statement for each shipping document with respect to the goods being properly named, classified, described, packaged, marked and labeled, and otherwise in proper condition for transportation according to the applicable regulations.[52] Part of the stated rationale for this new requirement is to harmonize with international regulations that already require consignor's certification.

As consignors often rely on the supplier or manufacturer to provide the proper classification, consignors will be required to obtain documentary support from these parties for the classification of the goods.

4. INITIAL RECOMMENDATIONS FROM THE TSB INVESTIGATION AT LAC MÉGANTIC

On 23 January 2014, the TSB released its initial recommendations in relation to the earlier-referenced investigation at Lac-Mégantic.[53] The TSB recommendations focused on three key issues: the vulnerability of Class 111 tank cars,[54] route planning for the transport

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50 For the purposes of section 2.2.1, a proof of classification is any of a test report, a lab report, or such other document that explains how the dangerous goods were classified (*TDGR*, *supra* note 48, s 2.2.1(2)).

51 *TDGR*, *ibid*, Schedule 2, Special Provision 92.

52 *Ibid*, s 3.6.1.

53 Transportation Safety Board of Canada, *Rail Safety Recommendations* (23 January 2014), online: Transportation Safety Board of Canada <www.tsb.gc.ca/eng/recommandations-recommendations/rail/2014/rec-r1401-r1403.pdf> [*Recommendations*].

54 The majority of Class 111 tank cars are general-service cars such as the DOT-111 referred to above in the proposed amendments to the *TDGR*.

of dangerous goods, and requiring Emergency Response Assistance Plans (ERAPs) for large volumes of liquid hydrocarbons.

Transport Canada was given 90 days to respond to the initial recommendations of the investigation. On 23 April 2014, the Minister of Transport provided a response to the recommendations. Transport Canada's response is discussed in each of the individual sections below.

i. *Recommendation R14-01: Vulnerability of Class 111 Tank Cars*

> The Department of Transport and the Pipeline and Hazardous Materials Safety Administration require that all Class 111 tank cars used to transport flammable liquids meet enhanced protection standards that significantly reduce the risk of product loss when these cars are involved in accidents.[55]

In their response, Transport Canada stated that they were "immediately removing the least crash-resistant DOT-111 tank cars from dangerous goods service by directing the phase-out of tank cars that have no continuous reinforcement of their bottom shell."[56] Transport Canada also announced that any DOT-111 tank car that did not meet their recent January 2014 mandatory standards would have to be "phased out or refitted within three years if they will be used for the transportation of crude oil or ethanol."[57]

ii. *Recommendation R14-02: Route Planning and Analysis for the Transport of Dangerous Goods*

> The Department of Transport set stringent criteria for the operation of trains carrying dangerous goods, and requires railway companies to conduct route planning and analysis as well as perform periodic risk assessments to ensure that risk control measures work.[58]

In their response, Transport Canada stated that they would issue an emergency directive that would require "railway companies to immediately slow trains transporting dangerous goods and implement other key operating practices that respond to the TSB's recommendation."[59]

iii. *Recommendation R14-03: Requiring ERAPs for Large Volumes of Liquid Hydrocarbons*

The TSB recommended, at a minimum "[t]he Department of Transport require [ERAPs] for the transportation of large volumes of liquid hydrocarbons";[60] there is currently no such requirement. The TSB noted that requiring approved ERAPs would "consistently ensure that

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55 *Recommendations*, *supra* note 53 at 6.
56 "Remarks by the Honorable Lisa Raitt, Minister of Transport at a News Conference Regarding Transport Canada's Response to Interim Recommendations of the Transportation Safety Board of Canada" (23 April 2014), online: <news.gc.ca/web/article-en.do?nid=848029> [*Transport Canada Remarks*].
57 *Ibid*.
58 *Recommendations*, *supra* note 53 at 9.
59 *Transport Canada Remarks*, *supra* note 56.
60 *Recommendations*, *supra* note 53 at 11.

first responders have access, in a timely manner, to the required resources and assistance in the event of an accident involving significant quantities of flammable hydrocarbons."[61]

In their response, Transport Canada stated that they intend to "issue a direction to require shippers to develop emergency response assistance plans for crude oil, gasoline, diesel, aviation fuel, and ethanol when a single tank car is loaded with one of these designated flammable liquids."[62]

IV. LIQUEFIED NATURAL GAS PROJECTS

A. FEDERAL

1. CSA Z276 STANDARD ON LIQUEFIED NATURAL GAS — PRODUCTION, STORAGE AND HANDLING

The Canadian Standards Association (CSA) posted a draft of the next edition of the CSA *Z276 Standard on Liquefied Natural Gas (LNG) — Production, Storage and Handling*.[63] CSA Z276 will apply to the design, location, construction, operation, and maintenance of liquefied natural gas (LNG) facilities, and to the storage, vaporization, transfer, handling, and truck transport of LNG as well.

The most significant changes since the last edition of the CSA Z276 are the inclusion of membrane tanks and mobile LNG fuelling stations. Membrane tanks are now included in the sections of CSA Z276 dealing with impounding area and drainage system design and capacity.[64] There is also an ammonia test requirement for leak testing.[65] Membrane tanks must be designed to withstand a safe shutdown earthquake or an aftershock level earthquake without failure.[66] In addition, there have also been changes to the minimum separation distances for containment tanks.[67]

CSA Z276 also includes changes to its retroactivity provisions. For example, section 4.2 states that where existing plants, equipment, buildings, structures, and installations do not meet all of the provisions of the current edition of CSA Z276, they may remain in use provided they met the applicable design, fabrication, and construction layout provisions of the edition of CSA Z276 in effect at the time of approval or installation, and they may remain in use, provided that they do not constitute a significant risk to life or adjoining property.[68]

The public comment period for CSA Z276 closed 21 March 2014.

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61 *Ibid*.
62 *Transport Canada Remarks*, *supra* note 56.
63 *Z276-11 — Liquified natural gas (LNG) — Production, storage and handling* (CSA, 2011) [CSA Z276].
64 *Ibid*, s 5.2.2.
65 *Ibid*, s 7.5.1.
66 *Ibid*, s 7.1.5.7.
67 *Ibid*, s 5.2.4.
68 *Ibid*, s 4.2.

2. NEB EXPORT LICENCE APPROVALS

There has been a significant increase in the number of applications to the NEB by oil and gas companies to obtain LNG export licence approvals in the last year. As stated by the NEB, "[o]ne of the major impacts of [the increase in the Canadian gas resource base] is lower demand for Canadian gas in traditional gas markets in the United States and eastern Canada. As a result, the Canadian gas industry is seeking to access overseas gas markets through exports of LNG."[69]

LNG export licence applications must go through two stages of approval before licences are finally issued by the NEB. First, the NEB must consider, pursuant to Section 118 of the *National Energy Board Act*,[70] if the quantity of gas proposed to be exported is surplus to Canadian requirements. If the application meets this requirement, the NEB's decision to issue a licence is subject to an approval by the Governor in Council under section 4 of the *National Energy Board Act Part VI (Oil and Gas) Regulations*.[71]

At present, seven LNG licences have passed both stages of approval and have been issued.[72] The LNG export licences for four other LNG projects have been approved by the NEB, but have yet to receive Governor in Council approval.[73] Finally, three of the applications are recent enough that they are still under review by the NEB.[74]

A review of the NEB Letter Decisions for approved LNG export licences highlight three issues that will likely remain relevant for future export licence applications. These three issues are discussed in further detail below.

i. NEB's Mandate for Export Licence Applications is Limited to Section 118

For two of the LNG export licence approvals, the Industrial Gas Consumers Association of Alberta (IGCAA) provided submissions to the NEB that stated that the IGCAA "continue[d] to rely on the mandate of the NEB to ensure that export quantities do not negatively impact the price and availability of natural gas for domestic consumption and

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69 "NEB Approves Four LNG Export Licence Applications" (16 December 2013), online: CNW <www.newswire.ca/en/story/1280849/neb-approves-four-lng-export-licence-applications>.

70 RSC 1985 c N-7, s 118 [*NEB Act*].

71 SOR/96-244, s 4.

72 These licences are held by: (1) KM LNG Operating General Partnership; (2) BC LNG Export Co-operative, LLC; (3) LNG Canada Development Inc.; (4) Pacific NorthWest LNG Ltd.; (5) WCC LNG Ltd.; (6) Prince Rupert LNG Exports Limited; and (7) Woodfibre LNG Export Pte Ltd ("LNG Export Licence Application Schedule," online: NEB <www.neb-one.gc.ca/clf-nsi/rthnb/pplctnsbfrthnb/lngxprtlcncpplctns/lngxprtlcncpplctns-eng.html>).

73 These licences are proposed to be held by: (1) Jordan Cove LNG L.P.; (2) Triton LNG Limited Partnership; (3) Aurora Liquefied Natural Gas Ltd.; and (4) Oregon LNG Marketing Company LLC (*ibid*).

74 These applications were made by: (1) Pieridae Energy Ltd.; (2) Kitsault Energy Ltd.; and (3) Canada Stewart Energy Group Ltd (*ibid*).

further stated that it was concerned that the aggregate impact of multiple LNG export licence applications before the Board was not being considered."[75]

In declining to consider the IGCAA's suggestion, the NEB reiterated that its mandate was "limited to the Surplus Criterion as stated in section 118 of the NEB Act" and that the market price of natural gas is only "one indicator of market conditions as North American natural gas supply and demand adjust to changes in price signals."[76] The NEB made similar statements in their letter decision regarding Jordan Cove LNG's application for an export licence, where they held that

> [i]n the Board's view, the concerns of Landowners United and Citizens Against LNG Inc. are largely environmental and public interest in nature and are outside the Board's jurisdiction on natural gas export licence applications. The sole consideration of an export licence application is the Surplus Criterion identified in section 118 of the NEB Act.[77]

ii. Interpretation of Section 116 of the *National Energy Board Act*

Section 116 of the *NEB Act* states that, "[e]xcept as otherwise authorized by or under the regulations, no person shall export or import any oil or gas except under and in accordance with a licence issued under this Part."[78] In Prince Rupert LNG's application for an LNG export licence, they requested that the NEB provide them "authorization to export LNG on [their] own behalf, *and as an agent on behalf of affiliates and third parties*."[79] In accepting this request, the Board held that their view was that section 116 of the *NEB Act* "does not require the holder of the licence to also be the owner of the gas proposed for export; therefore the Board does not find it necessary to include a term on the licence permitting Prince Rupert LNG to act as agent on behalf of its affiliates and third parties, as it proposes."[80]

iii. Denial of Certain Exemptions from the Reporting Requirements

In Prince Rupert LNG Inc.'s (Prince Rupert) application for a LNG export licence, they requested that they be exempt from certain of the monthly reporting requirements required under section 4 of the *National Energy Board Export and Import Reporting Regulations*.[81] Prince Rupert argued that, in the context of their potential monthly reporting requirement, "the effect of exporting from a unique export point is that … Prince Rupert LNG would be

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75 *Re Pacific NorthWest LNG Ltd 5 July 2013 Application for a Licence to Export Liquefied Natural Gas* (16 December 2013), A55995, online: NEB <www.neb-one.gc.ca> at 4 [*Re Pacific*]; *Re WCC LNG Ltd 19 June 2013 Application for a Licence to Export Liquefied Natural Gas* (16 December 2013), A55993, online: NEB <www.neb.one.gc.ca> at 5.

76 *Re Pacific*, *ibid* at 5.

77 *Re Jordan Cove LNG LP 9 September 2013 Application for a Licence to Export Natural Gas* (20 February 2014), A58981, online: NEB <www.neb-one.gc.ca/> at 7.

78 *Supra* note 70, s 116.

79 *Re Prince Rupert LNG Exports Limited 17 June 2013 Application for a Licence to Export Liquefied Natural Gas* (16 December 2013), A55992, online: NEB <www.neb-one.gc.ca/> at 4 [*Prince Rupert* (NEB)] [emphasis added].

80 *Ibid*.

81 SOR/95-563.

unable to maintain the confidentiality of the details of export sales contracts between Prince Rupert LNG and its buyers, which are commercially sensitive documents."[82]

The NEB rejected Prince Rupert's argument, noting that "the information supplied by an export licence holder to the Board is not necessarily the information that is published by the Board. The Board will continue to support market transparency while exercising discretion with respect to the information it chooses to release to the public."[83]

B. PROVINCIAL LNG APPROVALS

While many of the proposed LNG projects in British Columbia have received their NEB LNG export licence, environmental assessment processes under both the *Canadian Environmental Assessment Act, 2012* and British Columbia's *Environmental Assessment Act* are underway for only a handful of the projects.[84]

On 7 March 2014, *Draft Application Information Requirements for an Environmental Assessment Certificate Application* were submitted to the British Columbia Environmental Assessment Office (EAO) by Prince Rupert LNG Ltd. in respect of an LNG export project located on Ridley Island, British Columbia.[85] The project site is located on Federal Crown Land, and is reviewable under the *CEAA, 2012* and the *BCEAA*. The purpose of the document is to identify information that a project proponent is required to provide in an Application for an Environmental Assessment Certificate under the *BCEAA*.

On 20 February 2014, the EAO also approved the final *Application Information Requirements* for the Pacific NorthWest LNG Project that were submitted in November 2013.[86] Subsequently, on 25 March 2014, Pacific NorthWest LNG Limited Partnership submitted their formal Environmental Impact Statement and Environmental Assessment Certificate Application. The application is intended to meet the requirements of both the *CEAA, 2012* and the *BCEAA*.

While not directly related to the construction of specific LNG export terminals, on 7 October 2012, the British Columbia EAO issued a conditional Environmental Assessment Certificate to Quicksilver Resources Canada Inc. in respect of its Fortune Creek Gas Plant

82 *Prince* Rupert (NEB), *supra* note 79 at 6.
83 *Ibid*.
84 SC 2012, c 19, s 52 [*CEAA, 2012*]; SBC 2002, c 43 [*BCEAA*]. The exception is the Kitimat LNG Project, which has already received its environmental assessment certificate from the British Columbia Environmental Assessment Office. See Ministry of Environment, "Kitimat LNG Receives Approval from Province" (6 June 2006), online: Government of British Columbia <www2.news.gov.bc.ca/news_releases_2005-2009/2006ENV0048-000746.htm>.
85 Prince Rupert LNG, *Draft Application Information Requirements for an Environmental Assessment Certificate Application* (7 March 2013), online: Government of British Columbia <a100.gov.bc.ca/appsdata/epic/documents/p402/1394577049623_7b1bd1388d36ed1ad3b48fb9cf3bd4a93017c0ff97a09bfe77eb18d45892a624.pdf>.
86 Pacific Northwest LNG, *Application Information Requirements as Approved by Environmental Assessment Office on February 20, 2014*, online: Government of British Columbia <a100.gov.bc.ca/appsdata/epic/documents/p396/1392924114383_64fa66d9682a0b746f9ad04ef89ece5bfa5f6de34f0aaa171255faf9a32dc756.pdf>.

Project, which may supply LNG operations.[87] The British Columbia EAO was satisfied that the proponent had discharged its duty to consult with First Nations in respect of the plant. Fifty-two conditions were attached to the approval, which were intended to mitigate the potential environmental and social impacts of the project.

British Columbia also entered into a sole proponent agreement with Woodside Energy Ltd., an Australian company that has proposed an LNG export facility near Prince Rupert on the Grassy Point parcel.[88] The agreement gives Woodside the exclusive right to negotiate a long-term tenure for an LNG facility at Grassy Point.

V. RENEWABLE ENERGY AND POWER

A. ONTARIO

1. REGULATORY AND COURT ACTIONS

i. *Trillium Power Wind Corp. v. Ontario (Ministry of Natural Resources)*[89]

The appellant, Trillium Power Wind Corporation (Trillium) brought an action against Ontario in respect of a partially-developed wind power project that was cancelled by regulatory action. It pleaded for relief under breach of contract, unjust enrichment, taking without compensation, negligent misrepresentation, negligence, misfeasance in public office, and intentional infliction of economic harm. At motions court, the appellant's claim was summarily dismissed in its entirety. The motions judge held that the decision to cancel outstanding wind projects was a core policy decision and immune from scrutiny.

The Court of Appeal held that the motion court erred in dismissing the claim for misfeasance in public office, but was otherwise correct. It permitted the appellant to advance its claim against Ontario, but only on the grounds that Ontario's conduct was specifically intended to injure the appellant.

The appellant's claim for misfeasance was grounded in an allegation of bad faith. It claimed that the responsible minister had cancelled its project to prevent political embarrassment during the election season in the riding where it was being developed. That ground was rejected. Instead, the Court permitted the claim to advance on the basis that the government had cancelled the project in order to prevent a project financing from closing.

Subsequent to the appeal, Trillium amended its statement of claim and, as of this writing, is proceeding with the action.

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87 *Environmental Assessment Certificate # E13-03* (7 October 2013), online: Government of British Columbia <a100.gov.bc.ca/appsdata/epic/documents/p379/1381341989111_b90f61e89592b8a615f367c5ba77ce5ee4114b647f0c414c5a3f618614b48068.pdf>.

88 See "Second LNG Agreement reached for Grassy Point with Woodside" (16 January 2014), online: British Columbia Newsroom <www.newsroom.gov.bc.ca/2014/01/second-lng-agreement-reached-for-grassy-point-with-woodside.html>.

89 2013 ONCA 683, 117 OR (3d) 721.

ii. *Lewis v. Director, Ministry of the Environment*[90]

The Ontario Ministry of the Environment (MOE) issued an approval to Bornish Wind LP to construct, install, operate, use, and retire a wind facility with a capacity of 72 megawatts. Robert Lewis appealed the decision to the Ontario Environmental Review Tribunal (ERT). He alleged that the wind facility would cause serious and irreversible harm to the environment pursuant to section 142.1(3) of the *Environmental Protection Act* (Ontario).[91]

The ERT noted that the test for harm was whether the appellant could prove it on the civil balance of probabilities, and that the evidence of potential harm was insufficient to meet that burden. When determining whether a project would harm the environment, an "ecosystem" approach was held to be necessary. Such an approach considers harm at many different scales, including individual species, ecosystems, habitats, and other structures.

The ERT held that evidence of actual harm is necessary to prove that a project will cause serious and irreversible harm to plant life, animal life, or the natural environment. It found that Lewis had not given evidence of actual harm, only potential harm, and that he had not proven harm on the balance of probabilities. It dismissed his application.

iii. *Alliance to Protect Prince Edward County v. Director, Ministry of the Environment*[92]

The Ontario MOE issued a renewable energy approval to the general partner of Ostrander Point Wind Energy LP to construct nine wind turbine generators on 324 hectares of provincial Crown land on the south shore of Prince Edward County, Ontario. The Alliance to Protect Prince Edward County (APPEC) and the Prince Edward County Field Naturalists (PECFN) appealed the decision to the ERT pursuant to section 142.1 of the *EPA*.[93] Section 145.2.1(2) of the *EPA* requires the ERT to determine whether the renewable energy approval will cause: (1) serious harm to human health; or (2) serious and irreversible harm to plant life, animal life, or the natural environment. While the appellants alleged that both aspects of the section 145.2.1(2) test were met, the ERT only accepted their argument under the second branch of the test and revoked the decision of the Director of the Ontario MOE.

a. The Project Caused No Serious Harm to Human Health

The appellants argued, relying on the 2011 ERT decision of *Erickson v. Director, Ministry of the Environment*,[94] that "the evidence of persons suffering serious harm from other windfarms under a variety of conditions, combined with a Case Definition [of Adverse Health Effects in the Environs of Industrial Wind Turbines] proposed by Dr. Robert

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90 12 November 2013, 13-044, online: Ont ERT <www.ert.gov.on.ca/english/decisions/index.htm> [*Lewis*].

91 RSO 1990, c E.19 [*EPA*].

92 3 July 2013, 13-002/13-003, online: Ont ERT <www.ert.gov.on.ca/english/decisions/index.htm> [*Prince Edward*]. The Ontario Superior Court overturned this decision in *Ostrander Point GP Inc v Prince Edward County Field Naturalists*, 2014 ONSC 974, 318 OAC 118 [*Ostrander*].

93 *Supra* note 91.

94 12 August 2011, 10-121/10-122, online: Ont ERT <www.ert.gov.on.ca/english/decisions/ index.htm> [*Erickson*].

McMurtry, leads to the conclusion that this Project will cause serious harm to the health of persons living in its vicinity."[95] In rejecting this argument, the ERT held that the appellants were unable to prove both that certain negative health effects were caused by wind turbines *and* that the Ostrander Point wind project itself would be the direct cause of "serious harm" to human health.[96] The ERT was particularly challenged by the fact that, in this case, "the subjective reporting by the post-turbine witnesses of both onset or aggravation of symptoms, and association with turbine noise, was shown to be unreliable" for a number of witnesses and that Dr. McMurtry's "Case Definition" was only a "preliminary attempt to explain symptoms that appear to be suffered by people … who live in the environs of wind turbines."[97]

b. The Project Would Cause Serious and Irreversible Harm to Plant Life, Animal Life, or the Natural Environment

In determining whether serious and irreversible harm would be caused to plant or animal life by the project, the ERT noted that the relevant factors to take into account and their particular weight should "be assessed on a case by case basis."[98] For plant or animal life that has previously been identified as being "at risk, a decline in the population or habitat of the species, or the alteration or destruction of such feature, will generally be factors with considerable weight."[99] However, for life that is not considered to be at risk, "the analysis would require greater preliminary consideration of such factors as the degree to which a species' population is threatened, the vulnerability of a species, the dispersal of the species' population and the quantity and quality of habitat."[100]

Applying the above test, the ERT held that the wind farm project would cause serious and irreversible harm to the Blanding's turtle, a "threatened species in Ontario."[101] In doing so, the ERT specifically examined each mitigation measure contained in the MOE approval to determine their effectiveness. It found that the "mitigation measures to be employed during the construction phase of the Project … would be effective to prevent serious and irreversible harm to [the] turtle from construction activities of the Project itself. However, such measures do not prevent use of the roads in the post-construction phase."[102] This was particularly relevant as one of the most serious threats to the viability of Blanding's turtle was its high road mortality rate. Accordingly, the ERT held that "mortality due to roads, brought by increased vehicle traffic, poachers and predators, directly in the habitat of Blanding's turtle, a species that is globally endangered and threatened in Ontario, is serious and irreversible harm."[103]

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95 *Prince Edward*, *supra* note 92 at para 24.
96 *Ibid* at para 28.
97 *Ibid* at paras 142-43.
98 *Ibid* at para 206.
99 *Ibid* at para 208.
100 *Ibid* at para 209.
101 *Ibid* at para 220.
102 *Ibid* at para 360.
103 *Ibid* at para 363.

iv. *Ostrander Point GP Inc. v. Prince Edward County Field Naturalists*[104]

In *Ostrander*, the Ontario Divisional Court was asked to review the decision of the Ontario ERT to revoke the Ontario MOE's approval of the Ostrander Point wind project. The Court ruled in favour of the wind developer, holding that the ERT had erred in revoking the approval. While PECFN and APPEC both appealed, this summary will focus on the Court's reasons for overturning the ERT's decision, which the Court reviewed on a standard of reasonableness.[105]

The Court took issue with the ERT's finding that the wind project would cause serious and irreversible harm to Blanding's turtle. While the Court was persuaded that serious harm would result to the turtle as a result of the project, they held that the fact that the ERT did not separate out their analysis of the "serious harm" factor from the "irreversible harm" factor was fatal.[106] The Court also held that the ERT, in any case, would not be able to establish "irreversible harm" to any species without a determination of the population of the species and the geographic area that is relevant to the species.[107] The Court noted that the ERT had not determined the population of Blanding's turtle in their analysis.

With respect to the ERT's emphasis on the project's increased road mortality of Blanding's turtle, the Court noted that "[w]hile it placed great emphasis on the issue of road mortality and the effect of the Project on road mortality, it is difficult to see how the Tribunal could make a determination that the Project would cause irreversible harm without any data as to the existing or projected traffic on the site."[108]

Additionally, the Court also held that the ERT was "dismissive" of the relevance of the permit the wind developer obtained under the Ontario *Endangered Species Act, 2007*, which allowed the developer to "kill, harm, harass, capture, possess and transport Blanding's Turtle" subject to the permit's conditions.[109] While the Court noted that the ERT did not have to take the permit's existence as "determinative," the ERT was

> obliged to explain how the fact that the [Ministry of Natural Resources] had concluded under the *ESA* that the Project would lead to an overall benefit to Blanding's turtle (notwithstanding the harm that would arise from the Project) could mesh with its conclusion that the Project would cause irreversible harm to the same species.[110]

Subsequent to the decision of the Ontario Divisional Court, the PECFN brought a motion to the Ontario Court of Appeal for a stay of the Divisional Court's decision, as well as a motion for leave to appeal the decision.[111] On 25 March 2014, the Ontario Court of Appeal,

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104 *Supra* note 92.
105 *Ibid* at paras 27-28.
106 *Ibid* at para 39.
107 *Ibid* at para 40.
108 *Ibid* at para 48.
109 *Ibid* at paras 50-51; SO 2007, c 6 [*ESA*].
110 *Ostrander*, *ibid* at para 70.
111 See *Prince Edward County Field Naturalists v Ostrander Point GP Inc*, 2014 ONCA 227, 119 OR (3d) 704 [*Ostrander Stay Decision*].

applying the three part test for a stay from *RJR-MacDonald Inc. v. Canada (Attorney General)*,[112] granted the stay motion. In granting the motion, the Ontario Court of Appeal noted that there were two serious issues that were "of broad public implication in the field of environmental law," including the correct interpretation of the term "serious and irreversible harm," the evidentiary standard to meet such term, and the correct remedies to be imposed by the ERT and a Divisional Court when dealing with a renewable energy approval issued by the Ontario MOE.[113]

B. NOVA SCOTIA

1. RENEWABLE ELECTRICITY REGULATIONS

The Nova Scotia *Electricity Act* mandates that a public utility: (1) allow qualifying generators to connect an electricity generation facility to its electrical grid; and (2) pay for any electricity that such a generator produces in accordance with the Community Feed-in Tariff Program (COMFIT).[114] Tariffs are set by the Nova Scotia Utility and Review Board.[115] These tariffs apply to facilities that produce renewable low-impact electricity, including:

(a) wind power;

(b) biomass, including the electricity produced from a combined heat and power plant;

(c) small-scale in-stream tidal;

(d) developmental tidal arrays; and

(e) other generation facilities as provided by the regulations.[116]

On 21 January 2014, the Government of Nova Scotia amended the *Renewable Electricity Regulations*[117] to provide further clarity on feed-in-tariff approval and power purchase agreement schemes. The amendments included the establishment of a process for evaluating applications for developmental tidal array feed-in-tariffs. In coming to a decision on such an application, the Minister of Energy must consider whether the application is consistent with the province's policies on renewable energy and its other energy objectives, and may consider the public interest.[118] As well, while qualification for a developmental tidal array feed-in-tariff continues to require a facility to be located in the "Province," that term is now defined so that it includes the land and submarine areas within the limits of the offshore areas under Nova Scotia's jurisdiction in the federal-provincial offshore regime.[119]

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112 [1994] 1 SCR 311 at 332-33 [*RJR MacDonald*]. That test is: (1) that the moving party has a serious issue for consideration on appeal; (2) that the moving party will suffer irreparable harm if the stay application is refused; and (3) that the balance of convenience favours the granting of the stay.
113 *Ostrander Stay Decision*, *supra* note 111 at para 15.
114 SNS 2004, c 25, s 4A(1).
115 *Ibid*, s 4A(2).
116 *Ibid*, ss 4A(7)(a)-(e).
117 NS Reg 155/2010, as amended by NS Reg 14/2014 [*Renewable Electricity Regulation*].
118 *Ibid*, s 28.
119 *Ibid*, s 3(1).

VI. ALBERTA ENERGY REGULATOR

This past year saw the Province of Alberta implement Phases 2 and 3 of its move towards a unified energy regulator. Phase 2 included the proclaiming into force of additional sections of the *REDA*[120] on 30 November 2013.[121] On 29 March 2014, Phase 3 also transferred certain powers to the Alberta Energy Regulator (AER) under various "specified enactments," including approvals that were formerly handled by Alberta Environment and Sustainable Resource Development for "energy resource activities."[122] At the same time, the AER has begun issuing more substantive decisions and an increasing number of regulatory bulletins. As the implementation phases of *REDA* have been well canvassed elsewhere, we thought it would be worthwhile to highlight six particular decisions and bulletins that the AER has released over the past year.

A. REGULATORY DECISIONS AND BULLETINS

1. AER, BULLETIN 2014-03, "REGULATORY APPROACH FOR SHALLOW THERMAL IN SITU OIL SANDS APPLICATIONS IN THE WABISKAW-MCMURRAY DEPOSIT OF THE ATHABASCA OIL SANDS AREA"[123]

On 28 January 2014, the AER announced that they would defer decisions on applications for certain thermal oil sands projects until the development of official regulatory requirements for steam-assisted gravity drainage (SAGD) projects. The AER is currently preparing a "technical review of the factors that affect reservoir containment of [SAGD] projects" that will assist them in preparing such regulations.[124]

There are two criteria on which the AER will base any decision to defer a SAGD application:

(1) The thermal project must fall within a designated area in the Wabiskaw-McMurray Deposit.[125] The AER is concerned that the shallow thermal resource in this area could increase the risk of steam and reservoir fluid releases if containment is compromised.

(2) The thermal project must "[a]ddress reservoir containment in a manner that is different from the approach the AER currently uses."[126] The current approach assesses containment "by establishing caprock integrity and determining the

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120 *Supra* note 23.

121 See AER, Bulletin 2013-04, "AER Implementation, Phase 2" (15 November 2013), online: <www.aer.ca/documents/bulletins/AER-Bulletin-2013-04.pdf>; AER, Bulletin 2013-05, "AER Implementation, Phase 2, Information Technology Implications" (22 November 2013), online: <www.aer.ca/documents/bulletins/AER-Bulletin-2013-05.pdf>.

122 See *Specified Enactments (Jurisdiction) Regulation*, AR 201/2013.

123 28 January 2014, online: AER <www.aer.ca/documents/bulletins/AER-Bulletin-2014-03.pdf> [Bulletin 2014-03].

124 *Ibid* at 1.

125 A map of the designated area can be found *ibid* at 3.

126 *Ibid* at 1.

maximum operating pressure,"[127] calculated as 0.8 x caprock fracture closure gradient x depth to base of caprock.

2. *DOUGLAS AND DOROTHY HOLLANDS, SECTION 33 APPLICATION FOR PIPELINE REMOVAL, LEDUC-WOODBEND FIELD*[128]

The applicants applied to the then-ERCB for an order requiring Alberta Products Pipeline Ltd. (APPL) to remove a portion of its pipeline. The application was made pursuant to section 33 of the *Pipeline Act*,[129] which permits the AER to relocate a section of pipeline. The applicants asked to relocate the pipeline section to a different location on their lands.

The applicants and APPL were successors in interest to the original lessor and lessee of the lands. A separate application concerning the interpretation of the lease had been brought to the Alberta Court of Queen's Bench. The AER declined to consider matters related to the interpretation of the lease.

The question before the AER was whether the application was in the public interest. The AER considered the factors set out in section 3 of the *REDA* in making its determination. It held that the potential annexation of the applicants' lands by the City of Leduc was not determinative as to the pipeline's social effects, that the economic benefit of relocating the pipeline was uncertain because the applicants had no firm development plans, that the applicants failed to provide sufficient evidence of environmental benefit from relocating the pipeline, and that the applicants failed to provide sufficient evidence of potential impacts on neighbouring landowners. The AER dismissed the application.

3. *GRIZZLY RESOURCES LTD. AND SINOPEC DAYLIGHT ENERGY LTD., APPLICATIONS FOR WELL, PIPELINE, AND FACILITY LICENCSES AND A REGULATORY APPEAL OF A PIPELINE LICENCE, PEMBINA FIELD*[130]

Grizzly Resources Ltd. (Grizzly) applied for a licence to drill a directional well to produce crude oil with a high hydrogen sulphide (H_2S) content. Sinopec Daylight Energy Ltd. (Sinopec) applied for approvals to construct, operate, or vary the operations of several pipelines in connection with the Grizzly well. Two interveners (Interveners) appealed an earlier approval granted to Sinopec in respect of one of its pipelines. The Interveners' land was within the Emergency Planning Zone (EPZ) of the proposed Grizzly well. A hearing was held, during which numerous other interveners gave evidence.

The AER held that the Grizzly well and Sinopec pipelines were in the public interest. It held that Grizzly and Sinopec had met the public consultation requirements. It approved the project design, noting that safety concerns regarding the proposed fiberglass pipeline would be mitigated by proper installation. It held that the proposed emergency response plans met AER requirements. The AER approved both applications subject to two conditions on drilling and flaring. It rejected the Interveners' appeal.

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127 *Ibid*.
128 25 February 2014, 2014 ABAER 003, online: AER <www.aer.ca/>.
129 RSA 2000, c P-15, s 33.
130 31 October 2013, 2013 ABAER 019, online: AER <www.aer.ca/>.

4. *TECK RESOURCES LIMITED, APPLICATION FOR OIL SANDS EVALUATION WELL LICENCES, UNDEFINED FIELD*[131]

The applicant Teck Resources Ltd. (Teck) applied for licences to drill 177 vertical crude bitumen oil sands evaluation wells in a winter corehole drilling program (the Program). Teck submitted oil sands exploration applications pursuant to section 2.030 of the *Oil and Gas Conservation Rules*.[132]

Three First Nations groups intervened in the application. A public hearing was held. The AER dismissed the First Nations groups' claims. It held that consultation with two of the groups was adequate, and accepted that Teck would increase its consultation efforts going forward. The AER also held that the environmental impacts of the Program would be minimal, notwithstanding gaps in the data used to predict those impacts. Finally, any disruptions to traditional land use caused by the Program would be minimal. Ultimately, the winter drilling program was approved.

5. *KALLISTO ENERGY CORP., APPLICATION FOR A WELL LICENCE, CROSSFIELD EAST FIELD*[133]

The applicant, Kallisto Energy Corp. (Kallisto), applied for a licence to drill an oil well under section 2.020 of the *OGCR*.[134] A group of companies (the Interveners) owned and operated a commercial natural gas storage cavern in depleted pools roughly 290 metres from the proposed well. The Interveners opposed the well, and claimed that it would produce storage gas as it targeted the same formation in which the gas was stored.

The AER held that it was not required to deny Kallisto a well licence in order to create a buffer zone around the Interveners' gas storage facility. A well licence does not entitle its holder to rights other than what it holds under a mineral lease. It does not operate to transfer ownership of a substance. Any trespass or conversion would still be tortious activity under the jurisdiction of the courts. Whether or not a particular formation is porous at a proposed well location does not affect the ability of the AER to grant the well licence.

The AER approved Kallisto's well licence. It required Kallisto to measure gas produced from the well in excess of the solution gas the well would already have produced, and return such gas to the Interveners. It held that it had no jurisdiction to award anticipatory compensation. Finally, it held that storage operators such as the Interveners should ensure that they have secured title to adjacent lands which, if developed, could harm their storage operations.

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131 21 October 2013, 2013 ABAER 017, online: AER <www.aer.ca/>.
132 Alta Reg 151/1971 [*OGCR*].
133 23 July 2013, 2013 ABAER 013, online: AER <www.aer.ca/>.
134 *Supra* note 132.

6. *CANADIAN NATURAL RESOURCES LIMITED, APPLICATION FOR THE KIRBY EXPANSION PROJECT*[135] AND RELATED AER LETTER DECISIONS

On 3 April 2014, an AER panel held that a proposed public hearing for Canadian Natural Resources Limited's (CNRL) Kirby Expansion Project should be cancelled. The AER had received a number of submissions from various interested parties (the majority of which were Aboriginal groups), who argued that they were entitled to be heard at a public hearing because they met the "directly and adversely affected" test for standing under the *REDA*.[136] However, the AER held that none of the parties who provided submissions were "directly and adversely affected" pursuant to Section 9(3) of the *Rules of Practice* which states:

> (3) The Regulator may refuse to allow a person to participate in the hearing on an application if the Regulator is of the opinion that any of the following circumstances apply:
>
> (a) the person's request to participate is frivolous, vexatious, an abuse of process or without merit;
>
> (b) the person has not demonstrated that the decision of the Regulator on the application may directly and adversely affect the person;
>
> (c) in the case of a group or association, the request to participate does not demonstrate to the satisfaction of the Regulator that a majority of the persons in the group or association may be directly and adversely affected by the decision of the Regulator on the application;
>
> (d) the person has not demonstrated that
>
> (i) the person's participation will materially assist the Regulator in deciding the matter that is the subject of the hearing,
>
> (ii) the person has a tangible interest in the subject-matter of the hearing,
>
> (iii) the person's participation will not unnecessarily delay the hearing, and
>
> (iv) the person will not repeat or duplicate evidence presented by other parties;
>
> (e) the Regulator considers it appropriate to do so for any other reason.[137]

In the various letter decisions issued by the AER to each of the parties who argued they were directly and adversely affected by CNRL's application, the AER hearing panel agreed that "some degree of location or connection between the work proposed and the right asserted"[138] was a valid consideration in assessing whether a party is directly and adversely affected. The

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135 3 April 2014, 2014 ABAER 006, online: AER <www.aer.ca/>.

136 *REDA*, *supra* note 23, s 34. Section 9(3) of the *Alberta Energy Regulator Rules of Practice*, AR 99/2013 [*Rules of Practice*], sets out situations where the AER may deem a person to not meet this threshold.

137 *Rules of Practice*, *ibid*.

138 See e.g. Letter Decision from Gary D Perkins to Councilor Cecil Janvier et al (27 March 2014), online: Ablawg <ablawg.ca/wp-content/uploads/2014/06/AER-Letter-decision-to-Cold-Lake-First-Nation-re-CNRL's-Kirby-Expansion-Project.pdf> at 2 [CLFN Letter Decision], citing *Dene Tha' First Nation v Alberta (Energy and Utilities Board)*, 2005 ABCA 68, 363 AR 234 at para 14.

AER hearing panel went on to quote a decision of the Alberta Environmental Appeals Board, which summarized the "directly affected" test as follows:

> *What the Board looks at when assessing the directly affected status of an appellant is how the appellant will be individually and personally affected.* The more ways in which the appellant is affected, the greater the likelihood of finding that person directly affected. The Board also looks at how the person uses the area, how the project will affect the environment, and how the effect on the environment will affect the person's use of the area. The closer these elements are connected (their proximity), the more likely the person is directly affected. The onus is on the appellant to present a prima facie case that he or she is directly affected.[139]

While many of the Aboriginal groups argued that CNRL's project would impact their ability to exercise their Aboriginal and treaty rights, the AER hearing panel rejected these arguments, holding that many of the groups had failed to provide enough specific evidence to support these claims. Each of the letter decisions uses slightly different wording to reject such arguments; however, the following quote from the Cold Lake First Nation (CLFN) letter decision is representative of the AER hearing panel's position:

> In conclusion, the Panel has decided that CLFN has not demonstrated that it may be directly and adversely affected if the Project proceeds, or that a CLFN member's use of lands or natural resources in or near the Project lands may be impacted by the Project in a way that results in a direct and adverse effect on CLFN or the member. The information in CNRL's application does not locate any CLFN uses within or in specific proximity to the Project area. The Panel has therefore decided that CLFN will not be extended participation rights in a hearing of the Project application.[140]

VII. OIL AND GAS

A. ALBERTA

1. COURT DECISIONS

i. *Pembina Institute v. Alberta (Environment and Sustainable Resources Development)*[141]

In *Pembina*, the Pembina Institute and the Fort McMurray Environmental Association applied for judicial review of a decision of the Director, Northern Region of Alberta Environment and Sustainable Resources Development (in this section, the Director) to reject a "Statement of Concern" (in this section, a Statement) submitted by the Oil Sands Environmental Coalition (OSEC), of which the two applicants are members, under the Alberta *Environmental Protection and Enhancement Act* and *Water Act* (collectively, in this

139 CLFN Letter Decision, *ibid* at 3, citing *Tomlinson v Director, Northern Region, Operations Division, Alberta Environment and Sustainable Resource Development re: Evergreen Regional Waste Management Services Commission*, (3 April 2013) 12-033-ID1, online: AEAB <www.eab.gov.ab.ca/> at para 28 [emphasis added].

140 CLFN Letter Decision, *ibid* at 6.

141 2013 ABQB 567, 571 AR 184 [*Pembina*].

section, the *Acts*).[142] The Statement was submitted in relation to an application by Southern Pacific Resource Corp. to construct a SAGD project on the MacKay River in Alberta.

The *Acts* give a person the right to submit a Statement to the Director if they are directly affected by an application for certain oil and gas projects. The acceptance of a Statement by the Director "in turn entitles the person to other participatory rights under the *Acts*, including the right to appeal the Director's decision to issue an approval."[143] The Director had determined that the Statement did not sufficiently demonstrate that OSEC or its members were directly affected by the SAGD application.[144]

The Alberta Court of Queen's Bench quashed the Director's decision, holding that the decision breached four principles of natural justice as outlined in *Baker v. Canada*:[145]

1. a fair and open procedure
2. the right to be heard
3. consideration by the decision maker tasked with the duty to decide and
4. that decisions are to be free from a reasonable apprehension of bias.[146]

a. A Fair and Open Procedure

Justice Marceau was persuaded by a previously unpublished "Briefing Note," created in 2009 for the Deputy Minister of Alberta Environment. Justice Marceau held that a "fair and open procedure does not allow [Alberta Environment] to ignore the purposes of the Act as published … while apparently operating under an undisclosed policy (the Briefing Note)."[147] He also found that the Briefing Note "contradict[ed] the publicly stated policies of the *EPEA* encouraging public participation in the regulatory process."[148]

b. The Right to be Heard

The rights of both the Pembina Institute and the Fort McMurray Environmental Coalition were also breached as a result of the Briefing Note. Justice Marceau held, since neither group were informed of the Briefing Note, that they "consequently could not have answered the allegation [in the Briefing Note] that Pembina was regarded as uncooperative because it had withdrawn from [the Cumulative Environmental Management Association] and had published negative comments about oil sands development."[149]

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142 *Environmental Protection and Enhancement Act*, RSA 2000, c E-12 [*EPEA*]; *Water Act*, RSA 2000, c W-3.
143 *Pembina*, *supra* note 141 at para 2.
144 *Ibid* at para 19.
145 [1999] 2 SCR 817 [*Baker*].
146 *Pembina*, *supra* note 141 at para 25.
147 *Ibid* at para 33.
148 *Ibid*.
149 *Ibid* at para 34.

c. Consideration by the Decision Maker Tasked with the Duty to Decide

Justice Marceau found the Briefing Note particularly relevant under this principle, which he interpreted

> as a formula for rejection of future submissions of Statements of Concern from Pembina and OSEC. The principles of natural justice clearly require the decision maker to not consider irrelevant and improper reasons. Since as a matter of policy the Director was told to consider whether the Statement of Concern filer was cooperative and whether it had published negative media about the oil sands in coming to the Director's conclusion, the reasons are fatally flawed.[150]

d. Decisions are Free from Reasonable Apprehension of Bias

Applying the test for reasonable apprehension of bias from *Committee for Justice and Liberty v. National Energy Board*[151] as set out in *Baker*, Justice Marceau held that a well-informed member of the public would find that the public participation objectives of the *EPEA* were "hijacked by the Briefing Note" which "basically says that the interpretation of 'directly affected' will be changed in such a way that OSEC will no longer qualify as a Statement of Concern filer for oil sands projects."[152]

ii. *Stewart Estate v. TAQA North Ltd.*[153]

Stewart is a lengthy and comprehensive decision of the Alberta Court of Queen's Bench that discusses a number of important issues relevant to oil and gas leases. In *Stewart*, the plaintiffs were the registered freehold owners of most of the surface, petroleum, and natural gas rights on a particular parcel of land near Crossfield, Alberta. The prior landowners had signed five freehold petroleum and natural gas leases that covered most of the land. A dispute arose when the plaintiffs claimed that the leases had been terminated under a term of the leases that stated that if production from the leases ceased, the lease would no longer remain in force unless the lessee commenced further drilling or working operations within 90 days.

Between mid-1995 and early-2011, the sole well that was responsible for the pooled production of all five leases was shut-in, and the previous production royalty payments were changed to shut-in royalty payments. The leases also contained a "Third Proviso," which Justice Romaine summarized as follows:

> "if … any well … is shut-in, capped, suspended or otherwise not produced as the result of a lack of or an intermittent market, or any cause whatsoever beyond the Lessee's reasonable control, the time of such

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150 *Ibid* at para 35.

151 [1978] 1 SCR 369 at 394, citing *Re Canadian Arctic Gas Pipeline Ltd* (1975), [1976] 2 FC 20 at 29: "[W]hat would an informed person, viewing the matter realistically and practically — and having thought the matter through — conclude. Would he think that it is more likely than not that [the decision-maker], whether consciously or unconsciously, would not decide fairly."

152 *Pembina*, *supra* note 141 at para 37.

153 2013 ABQB 691, 92 Alta LR (5th) 141 [*Stewart*].

> interruption or suspension or non-production shall not be counted against the Lessee…", or a slight variation on this wording.[154]

While the decision discussed a number of major issues, including a determination of who the proper parties to the lawsuit were and standing of certain parties, only two of the key issues are discussed in this summary: (1) whether any of the plaintiff's claims were statute-barred by the *Limitations Act*;[155] and (2) whether the leases had not been terminated as a result of the Third Proviso.

a. Limitations Issue

Justice Romaine held that many of the claims were barred by both the knowledge-based two-year limitations period and the ultimate 10-year limitations period under the *Limitations Act*. The plaintiffs argued that the first time they had knowledge as to whether the leases validly existed was when one of them met with a lawyer in 2003. The plaintiffs filed their claim in 2005.[156] However, the defendants argued that the plaintiffs knew or ought to have known about the claim shortly after the well was shut-in, when the production royalty payments were replaced by the shut-in royalty payments.

In rejecting the plaintiff's argument, the Court, applying a reasonable diligence standard, held that the plaintiffs "knew or ought to have known that production had ceased under the leases shortly after July 1995. By the end of November 1995, they ought reasonably to have known that production had ceased for more than 90 consecutive days."[157] The Court found that there was some evidence that at least one of the plaintiffs knew the significance of the royalty payments change in 1995.[158]

b. Lease Interpretation

Despite holding that the plaintiff's claims were statute-barred, Justice Romaine went on to consider the issue of whether the defendants were nonetheless immune from liability as a result of the Third Proviso. The defendant had to prove that the well was shut-in or production was suspended: "as the result of a lack of or an intermittent market, or any cause whatsoever beyond the Lessee's reasonable control"; and "as the result of any cause whatsoever beyond the Lessee's reasonable control, including … lack of or an intermittent market."[159]

With respect to the interpretation of the words "lack of an intermittent market" the defendants argued that interpreting the words literally would lead to "a lessee being required to produce a well at a loss or a break-even point if it sought to rely on the ameliorating sub-clauses to preserve the validity of the lease, a result that could not be considered the parties' intention when they entered into the lease with the intention of making a profit."[160] Justice

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154 *Ibid* at para 10.
155 RSA 2000, c L-12.
156 *Stewart*, *supra* note 153 at paras 187-88.
157 *Ibid* at para 197.
158 *Ibid* at para 193.
159 *Ibid* at para 514.
160 *Ibid* at para 520.

Romaine held that the phrase, "read in context and with a view to the reasonable intention of parties to a lease to profit from the extraction of leased substances, should be interpreted to mean lack of or an intermittent economical or profitable market."[161] The defendants proved that their situation fell within this definition.

When interpreting the phrase "any cause whatsoever beyond the Lessee's reasonable control," the Court rejected the plaintiff's argument that "events that were foreseeable by the parties at the time of entering into the leases do not fall within the meaning" of the phrase.[162] The Court held that it could not "be said that a drastic down-turn in the price of gas and accompanying high processing costs caused by external forces, the two factors relied upon by the Defendants in this case, are as inevitable or foreseeable as seasonal road bans"[163] and, accordingly, that the defendants were entitled to rely on this part of the Third Proviso to escape liability.

B. BRITISH COLUMBIA

1. FEE, LEVY, AND SECURITY REGULATION

As of 6 February 2014, applications to the British Columbia Oil and Gas Commission are subject to a new fee schedule as set out in the *Fee, Levy and Security Regulation*.[164] Fees of note include:

- Well drilling permit application fees have been decreased from $18,700 to $12,400 for first time permit holders, and increased from $10,700 to $12,400 for people who already hold permits;

- A new permit application fee has been instituted for major pipelines, with application fees of $2,000 plus $1,400 per kilometer for pipelines under 50 kilometers in length, and $370,000 plus $1,400 per kilometer for pipelines 50 kilometers or over in length; and

- Levies will be increased from $1.41 to $1.45 per cubic metre of petroleum and from $0.71 to $0.73 per thousand cubic meters of marketable gas, with the increase attributable to the development of the Science and Community Environmental Knowledge Fund.[165]

In addition, while there used to be no fees associated with permits for the use of oil and gas roads, the enactment of the *Oil and Gas Road Regulation*[166] has brought into force the following application fees:

161 *Ibid* at para 542.
162 *Ibid* at para 554.
163 *Ibid* at para 558.
164 BC Reg 8/2014; BC Oil & Gas Commission, Industry Bulletin 2014-02, "Changes to Fee, Levy and Security Regulation" (20 January 2014), online: <www.bcogc.ca/node/11148/down load/> [Industry Bulletin 2014-02].
165 Industry Bulletin 2014-02, *ibid*, Appendix.
166 BC Reg 56/2013.

- For winter access roads over 5 kilometers, $100 per kilometer;
- For all season access roads over 5 kilometers, $200 per kilometer; and
- For amendments to existing roads, $500 per road.[167]

It is also intended that there will be new fee categories for major projects.[168]

2. *OIL AND GAS ACTIVITIES ACT*

Bill 12, which received Royal Assent on 9 April 2014,[169] introduced changes to two oil and gas-related statutes in British Columbia: the *Oil and Gas Activities Act*[170] and the *Petroleum and Natural Gas Act*.[171] The changes for the *Oil and Gas Activities Act* are currently in force and the changes to the *Petroleum and Natural Gas Act* will come into force by regulation.

With respect to the *Oil and Gas Activities Act*, certain exemptions that existed for legacy pipelines have been removed.[172] Accordingly, certain legacy pipelines will now have to meet the requirements of permit holders under the *Oil and Gas Activities Act*, which includes responsibilities in regards to things such as environmental protection and record-keeping.[173] Such permit-holders will also have to comply with any other requirements of the permit, including permit expiration dates.[174]

More significant changes will be made to the *Petroleum and Natural Gas Act*, including amendments relating to permits, leases, and drilling licences. The new section 49.1 to the *Petroleum and Natural Gas Act* will provide that a "holder of drilling licence has the exclusive right to apply under the *Oil and Gas Activities Act* to drill for the Crown reserves referred to in the licence."[175] The section will also stipulate that "a drilling licence does not prohibit a person other than the holder … from carrying out … geological work or geophysical exploration in the area."[176] The holder of a drilling licence will also have to pay rent as prescribed by the relevant regulations.[177]

Amendments were also passed for the *Petroleum and Natural Gas Act* in regard to the reinstatement of leases. One of the new provisions to be added by Bill 12, section 63(2), states that if a lease expires, the Minister may reinstate it if the expiry was inadvertent or the result of circumstances, other than financial circumstances, beyond the control of the lessee.

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167 Industry Bulletin 2014-02, *supra* note 164 at 2.
168 *Ibid*.
169 Bill 12, *Natural Gas Development Statute Amendment Act, 2014*, 2nd Sess, 40th Leg, 2014 (assented to 9 April 2014), SBC 2014, c 11 [Bill 12].
170 SBC 2008, c 36.
171 RSBC 1996, c 361.
172 British Columbia Ministry of Natural Gas Development, Information Bulletin "Amendments improve management of oil and gas, strata properties" (26 February 2014), online: Government of British Columbia <www2.news.gov.bc.ca/news_releases_2013-2017/2014MNGD0008-000200.htm>.
173 See e.g. *Oil and Gas Activities Act*, *supra* note 170, ss 36-38.
174 *Ibid*, s 40.
175 Bill 12, *supra* note 169, s 25.
176 *Ibid*.
177 *Ibid*.

The Minister also has the ability to exempt a person from rental payments, at the Minister's discretion.[178]

C. MANITOBA

1. *CROWN ROYALTY AND INCENTIVES REGULATION*

On 20 December 2013 the Government of Manitoba amended the *Crown Royalty and Incentives Regulation*, issued under the *Oil and Gas Act* (Manitoba).[179] The amended regulation represents an update to the Crown royalty regime so as to further incentivize horizontal drilling over vertical drilling, but also so as to bring Manitoba's regime closer in line with the incentive volumes in Saskatchewan and Alberta. What follows are two of the more significant changes: the revision to the incentive volumes and the expansion of the solution gas conservation program.

Under the amended section 3.1(1) of the *Manitoba Royalty Regulation*, a new formula for "Holiday Oil Volume" (HOV) has been introduced. Firstly, the maximum available HOV, (which is applied as a reduced royalty, 3 percent, on the volume of oil produced for each producing month up to a certain volume from a well), has been scaled back from 10,000 cubic metres to 8,000 cubic metres. Secondly, new depth and trajectory thresholds have been introduced which, although reducing the HOV of the large majority of vertical wells down to 500 cubic metres, is intended to strongly incentivize increased horizontal and/or deep exploratory activity.[180] The new thresholds are as follows:

- 8,000 cubic metres if the well is a horizontal well, a deep development well completed for production in the Birdbear Formation or a deeper formation, or a deep exploratory well drilled below the Birdbear Formation;
- 4,000 cubic metres if the well is a non-deep exploratory well drilled more than 1.6 km from a well cased for production from the same or deeper zone;
- 500 cubic metres if the well is a vertical oil well; and
- 500 cubic metres if the well is a marginal oil well that undergoes a major work-over after 31 December 2013 but before 1 January 2019.[181]

The solution gas conservation incentive has also been modified. Section 3.2 provides for an exemption from payment of any royalty or production tax on gas captured from an approved, new solution gas conservation project. Projects must be initiated and approved by the Director and the exemption will apply from the project implementation date to the expiry

[178] *Ibid*, ss 32, 36.

[179] Man Reg 109/94 [*Manitoba Royalty Regulation*] as amended by Man Reg 201/2013; *Oil and Gas Act*, CCSM c O34.

[180] Under the previous formula, the incentive volume of a newly drilled, non-horizontal well could range from a minimum of 500 cubic metres up to a maximum of 10,000 cubic metres of oil in certain exploratory and oil pricing situations.

[181] *Manitoba Royalty Regulation*, *supra* note 179, s 3.1(1).

of the program on 31 December 2018. In addition, the exemption period for wells converted to injection after 31 December 2013 has been extended from 12 months to 18 months.[182]

This royalty regime will be in place until 1 January 2019.

D. QUEBEC

1. OIL DEVELOPMENT ON ANTICOSTI ISLAND

The Quebec government has recently shown an increased interest in the exploration and development of oil and gas resources on Anticosti Island, a large but sparsely populated island located in the Gulf of St. Lawrence. In February 2014, the Quebec government signed separate letters of intent to establish two joint ventures that would allow the exploitation and development of Anticosti Island's oil resources.[183]

The first letter of intent was announced on 13 February 2014, between Corridor Resources Inc., Petrolia Inc., Etablissements Maurel & Prom S.A. and the Quebec government (through its affiliates, Investissement Québec and Ressources Québec).[184] Under the terms of the letter of intent, the parties intend to invest up to $100 million in an exploration program, commencing in 2014, for the drilling of 15 to 18 stratigraphic wells in the first year, followed by three multiple fracture-stimulated wells in the second year.

The second letter of intent was also announced on 13 February 2014, between Junex Inc. and Ressources Quebec.[185] The parties intend to bring a third partner into the joint venture at a future date. Under the terms of the letter of intent, Ressources Québec intends to invest up to $45 million in the joint venture to allow for the completion of the evaluation of the oil exploration permits currently held by Junex Inc.

2. MUNICIPAL REGULATION OF DRILLING ACTIVITIES

In *Pétrolia inc. c. Gaspé (Ville)*,[186] the Court had to determine the validity of a municipal bylaw adopted by the City of Gaspé (in this section, the City). When Pétrolia Inc. sought to exploit oil reserves in the region, the City adopted two bylaws, the stated objective of which was the protection of the environment and, in particular, the protection of sources of water. Section 8 of the bylaw prohibits the introduction into the water of any substance susceptible of altering the quality of underground or surface water destined for human or animal consumption within certain distances from the sources of water. Sections 9 to 14 of the bylaw prohibit the introduction into the waterways, whether by drilling or any other process, of any

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182 *Ibid*, Schedule E, s 4.

183 Nicolas Van Praet, "Quebec oil juniors hopeful new Liberal government will honour Anticosti deals" *Financial Post* (8 April 2014), online <business.financialpost.com/2014/04/08/quebec-oil-juniors-hopeful-new-liberal-government-will-honour-anticosti-deals/?_lsa=a994-df77>.

184 "Corridor Announces $100 Million Anticosti Joint Venture — The Government of Quebec and Maurel & Prom to Invest" (13 February 2014), online: Corridor Resources Inc <www.corridor.ca/media/2014-press-releases/02132014.html>.

185 Nicolas Van Praet, "Quebec takes an inside seat in Anticosti Island oil development," *Financial Post* (13 February 2014), online: <business.financialpost.com/2014/02/13/quebec-takes-a-seat-at-development-table/?__lsa=d29a-63d0>.

186 2014 QCCS 360, 21 MPLR (5th) 73 [*Pétrolia*].

substance susceptible of altering the quality of underground or surface water outside of the zones provided for in section 8. A permit must be obtained from the City before any such substances may be introduced into the waterways.

Pétrolia sought declaratory relief pursuant to section 453 of the *Code of Civil Procedure*.[187] In particular, it sought a declaration that, among other things, the City's bylaw was ultra vires of the powers of the City and that it was incompatible with provincial laws and regulations and thus inoperative to the extent of any such incompatibility.[188] The Court first determined the pith and substance of the bylaw. It ruled that one of the objects of the bylaw, namely the protection of water quality, is duly authorized by the *Municipal Powers Act*,[189] which grants municipalities the power to protect the environment. The Court found, however, that the true pith and substance of sections 9 to 14 of the bylaw was to regulate drilling. However, the province already regulates drilling, and has reserved this power to itself pursuant to the *Mining Act*.[190] In addition, the Court noted that this matter is specifically subtracted from the jurisdiction of municipalities by section 246 of *An Act Respecting Land use Planning and Development*.[191] As such, the Court declared that sections 9 to 14 of the bylaw were ultra vires.[192] The Court also found that section 8 of the bylaw was incompatible with provincial regulation adopted under the *Mining Act*. Consequently, section 8 of the bylaw was declared to be inoperative as against Pétrolia's activities.[193]

E. NORTHWEST TERRITORIES

1. *NORTHERN JOBS AND GROWTH ACT*

The *Northern Jobs and Growth Act*[194] was passed in June 2013. It brought into force the *Northwest Territories Surface Rights Board Act*,[195] the *Nunavut Planning and Project Assessment Act*,[196] and amended the *Yukon Surface Rights Board Act*.[197]

The *Northwest Territories Surface Rights Board Act* provided for a Surface Rights Board in the territory to settle disputes between landowners and surface and subsurface rights holders,[198] which will replace the arbitration systems set up under certain land settlement agreements. This legislation accords with the Gwich'in Comprehensive Land Claims Agreement and the Sahtu Dene and Métis Comprehensive Land Claims Agreement, which imposed an obligation on Canada to establish a regime for surface rights legislation in the

187 CQLR c C-25, s 453.
188 *Pétrolia*, *supra* note 186 at para 18.
189 CQLR c C-47.1, s 4(4).
190 CQLR c M-13.1.
191 CQLR c A-19.1, s 246.
192 *Pétrolia*, *supra* note 186 at paras 55, 88.
193 *Ibid* at para 87.
194 SC 2013, c 14.
195 SC 2013, c 14, s 11 (repealed by *Devolution Act*, *supra* note 1, replaced by SNWT 2014, c 17) [*NWT SRB Act*].
196 SC 2013, c 14, s 2.
197 SC 1994, c 43.
198 *Supra* note 195, s 9.

Northwest Territories.[199] The amendments to the *Yukon Surface Rights Board Act* are meant to align that legislation with the *Northwest Territories Surface Rights Board Act*.[200]

The *Nunavut Planning and Project Assessment Act* establishes joint management of resources between the Inuit and the federal government in Nunavut; it has not yet come into force.

F. YUKON

1. *GAS PROCESSING PLANT REGULATION*

The Government of the Yukon introduced the *Gas Processing Plant Regulation*[201] to provide oversight of gas processing plants and liquefied natural gas facilities in the territory. The regulation is intended to be comprehensive and incorporate national operational standards. The Yukon Minister of Energy, Mines and Resources' stated goal in implementing the *Gas Processing Plant Regulation* is to "oversee the use of additional energy sources, such as liquefied natural gas, to replace diesel as a cheaper, safer and greener option to meet Yukon's current and future electricity needs."[202]

The *Gas Processing Plant Regulation* requires that the licensee of an LNG facility comply with CSA Z276[203] in all matters relating to the LNG facility. The licensee must also comply with any orders or directions of the Chief Operations Officer.[204] In addition, the Chief Operations Officer has the power to vary any of the requirements of a licence.[205]

A licensee must implement certain prescribed programs, which include monitoring, recording and auditing the plant's activities.[206] The processing plant or LNG facility must also have:

- a management system;[207]
- a safety program;[208]
- an environmental protection program;[209] and
- a non-destructive examination program.[210]

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199 Aboriginal Affairs and Northern Development Canada, "Backgrounder — Northwest Territories Surface Rights Board Act," online: <www.aadnc-aandc.gc.ca/eng/1352232835989/1352232884589>.
200 *Northern Jobs and Growth Act*, *supra* note 194, ss 12-16.
201 YOIC 2013/162 [*GPPR*].
202 Government of Yukon, Press Release, "Yukon government implements gas processing plant regulation" (6 August 2013), online: <www.gov.yk.ca/news/13-201.html>.
203 *GPPR*, *supra* note 201, s 5. CSA Z275 is discussed above in Part IV.A.1.
204 *GPPR*, *ibid*, s 6.
205 *Ibid*, s 7.
206 *Ibid*, s 8.
207 *Ibid*, s 12.
208 *Ibid*, s 13.
209 *Ibid*, s 14.
210 *Ibid*, s 15.

The activities of a plant may be suspended or terminated if the licensee does not comply with the terms of its licence, with penalties for non-compliance having a maximum amount of $500,000.[211]

Once a licence is issued, construction of the plant or facility must be commenced and completed by the respective dates on the licence.[212] Construction may not commence until detailed designs and specifications of components have been submitted to the Chief Operations Officer.[213] In addition, the *Gas Processing Plant Regulation* sets out various construction and safety requirements that must be met.[214]

After construction, a licensee must apply to the Chief Operations Officer for approval to operate.[215] An application for operation approval must include results of pressure testing, an operations and maintenance manual, an emergency procedures manual, a staffing plan, a training program, and any other information required by the Chief Operations Officer.[216]

The first licence issued under the *Gas Processing Plant Regulation* was an LNG licence issued to the Yukon Electrical Company Limited.[217] The licence is for a 25 year term, and enables the company to install LNG storage and vaporization facilities in its existing system at the Watson Lake power plant.[218]

G. FEDERAL

1. *ENERGY SAFETY AND SECURITY ACT*

On 30 January 2014, Bill C-22, the *Energy Safety and Security Act*,[219] passed its first reading in the House of Commons. While the Bill has two parts, only the first is relevant for the purposes of this article, which adds to and amends provisions of the *Canada Oil and Gas Operations Act*,[220] the *Canada Petroleum Resources Act*,[221] the *Canada-Newfoundland Atlantic Accord Implementation Act*,[222] and the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*.[223] The changes are intended to increase safety measures in the event of an offshore oil spill.[224]

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211 *Ibid*, ss 9, 51-53.
212 *Ibid*, s 17(1).
213 *Ibid*, s 19(1).
214 *Ibid*, ss 20-23.
215 *Ibid*, s 24.
216 *Ibid*, s 25.
217 Government of Yukon, Press Release, "Government of Yukon authorizes natural gas power generation in Watson Lake" (10 January 2014), online: <www.gov.yk.ca/news/14-003.html>.
218 *Ibid*.
219 Bill C-22, *An Act respecting Canada's offshore oil and gas operations, enacting the Nuclear Liability and Compensation Act, repealing the Nuclear Liability Act and making consequential amendments to to other Acts*, 2nd Sess, 41st Parl, 2013 (as amended by the standing committee on Natural Resources and reported to the House on 11 June 2014) [*Energy and Safety and Security Act*].
220 *Supra* note 2.
221 *Supra* note 10.
222 SC 1987, c 3.
223 SC 1988, c 28.
224 Natural Resources Canada, News Release, "Harper Government Introduces Energy Safety and Security Legislation," (30 January 2014), online: <www.nrcan.gc.ca/media-room/news-release/2014/14656>.

The main purpose of the *Energy Safety and Security Act* is to increase environmental liability for offshore oil spills. The key points to be taken from the *Energy Safety and Security Act* are that it establishes the "polluter pays" principle, maintains unlimited liability where negligence is involved, raises the caps on absolute liability to $1 billion for any offshore area (whether Atlantic or Arctic), allows the government to seek environmental damages, and clarifies that permits holders are responsible for all contractors.[225]

2. *OFFSHORE HEALTH AND SAFETY ACT*

On 24 October 2013, Bill C-5, the *Offshore Health and Safety Act*[226] passed its first reading in the House of Commons. While the *OHSA* amends a number of other acts, its main purpose is to amend the *Canada-Newfoundland Atlantic Accord Implementation Act*[227] and the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*[228] to create an occupational health and safety framework for workplaces offshore of Newfoundland and Labrador, and Nova Scotia.[229] The *OHSA* also proposes to repeal the current occupational health and safety framework for offshore workplaces, which currently adopts Newfoundland and Labrador and Nova Scotia provincial legislation.[230]

The new occupational health and safety framework sections would apply to: (1) workplaces that are "situated within the offshore area for the purposes of exploration, production, conservation, or processing of petroleum"; and (2) "to employees and other passengers while — and immediately before — being transported on a passenger craft to, from, and between such offshore workplaces."[231]

The *OHSA* was reviewed by the Standing Committee on Natural Resources, who presented their report to the House of Commons on 12 February 2014. The *OHSA* received Royal Assent on 19 June 2014.

3. NORTHERN GATEWAY JOINT REVIEW PANEL REPORT

The Government of Canada and the Provinces of Alberta and British Columbia convened a Joint Review Panel (JRP) under the *CEAA, 2012*[232] to evaluate the proposed Northern Gateway Pipeline (the Project).

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225 *Energy Safety and Security Act*, *supra* note 219, Summary.

226 Bill C-5, *An Act to amend the Canada-Newfoundland Atlantic Accord Implementation Act, the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act and other Acts and to provide for certain other measures*, 2nd Sess, 41st Parl, 2013 (as assented to 19 June 2014) SC 2014, c 13 [*OHSA*].

227 *Supra* note 222.

228 *Supra* note 223.

229 Parliamentary Information and Research Service, *Legislative Summary of Bill C-5: An Act to Amend the Canada-Newfoundland Atlantic Accord Implementation Act, the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act and other Acts and to provide for certain other measures* by Penny Becklumb et al (Ottawa: Library of Parliament, 2013) (revised on 2 April 2014) at 1 [*Legislative Summary*].

230 *Ibid* at 4. See also *OHSA*, *supra* note 226, ss 28, 69.

231 *Legislative Summary*, *ibid* at 5. See also *OHSA*, *ibid*, s 45.

232 *Supra* note 84.

The JRP indicated that it was satisfied that the Project, subject to the 209 conditions set out in Appendix 1 of the JRP's report and the commitments made by Northern Gateway through the hearing, is required by the present and future public convenience and necessity.[233] In this regard the JRP recommended to the Governor in Council that certificates of public convenience and necessity be issued pursuant to Part III of the *NEB Act*.[234]

The Panel made the recommendation for issuance of certificates notwithstanding two determinations of significant adverse environmental effects associated with the Project and indicated that in its view such effects are justified in the circumstances. The Panel also held that the toll principles are acceptable for developing tolls for both the oil pipeline and the condensate pipeline in a subsequent Part IV application subject to the Panel's conditions. The Panel further ordered that Northern Gateway be designated a Group 1 company.[235]

4. JACKPINE MINE EXPANSION JOINT REVIEW PANEL REPORT[236]

As part of a planned expansion, Shell Canada Energy, the operator of the Jackpine oilsands mine (Jackpine Mine), applied to the ERCB for an amendment to the Jackpine Mine Phase 1 Approval permitting the increase of production of bitumen by 15,900 cubic meters per day. Shell also submitted an EIA a part of its application. A JRP was convened between Alberta Environmental and Sustainable Resource Development (ESRD), Canadian Environmental Assessment Agency (CEAA), and the ERCB. Provincial and federal approvals were necessary for the approval.

After the JRP was convened, *CEAA, 2012* and *REDA* came into force. The AER took over from the ERCB.

The JRP concluded that the proposed expansion was in the public interest. It found that the project would provide significant economic benefits to the region, the province, and Canada. It held that the anticipated significant adverse effects on wildlife and vegetation were justified. It approved the AER application subject to conditions.[237]

H. KEYSTONE XL PIPELINE

The approval of the Keystone XL Pipeline has remained an ongoing topic throughout 2013 and into the early parts of 2014. While it had been widely speculated that US President Barack Obama would make a final decision on the approval of the pipeline sometime in early 2014, the timing of any such decision still remains undetermined. Supporters of the pipeline

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233 *Considerations: Report of the Joint Review Panel for the Enbridge Northern Gateway Project*, vol 2 (Calgary: National Energy Board, 2014) at 6 [*JRP Report*].
234 *Supra* note 70.
235 *JRP Report, supra* note 233 at 6.
236 *Shell Canada Energy, Application to Amend Approval 9756, Jack Mine Expansion Project, Fort McMurray Area* (8 July 2013) 2013 ABER 011, online: AER <www.aer.ca/>.
237 *Ibid* at para 8.

were concerned by statements made by President Obama last year that the pipeline would not be approved if it caused carbon emissions from the Alberta oil sands to increase.[238]

The US State Department recently issued a report (in this section, the Report) which concluded that the pipeline would be unlikely to increase greenhouse gas emissions at a significant rate.[239] The Report found that the Keystone XL Pipeline "is unlikely to significantly affect the rate of extraction in oil sands areas (based on expected oil prices, oil-sands supply costs, transport costs, and supply-demand scenarios)."[240] The Report also found that "[a]ssuming construction of the proposed Project were to occur in the next few years, climate conditions during the construction period would not differ substantially from current conditions" and that during the "subsequent operational time period" of the Keystone XL Pipeline, many climate change effects were "anticipated to occur regardless of any potential effects from the proposed Project."[241] The Report will likely be used by the US State Department in making its determination as to whether approval of the pipeline is in the US national interest.[242]

On 18 April 2014, the U.S. State Department again announced that the Keystone XL Pipeline would face additional delays.[243] In their statement to the media, the State Department said that it needed additional time to determine the impact a Nebraska court challenge to the Keystone XL Pipeline may have on the routing of the pipeline.[244]

VIII. ENVIRONMENTAL PROTECTION

A. FEDERAL

1. *TRANSBOUNDARY WATERS PROTECTION ACT*

The federal government introduced amendments to the *International Boundary Waters Treaty Act*[245] to prohibit the bulk removal of water from the Canada–US border.[246] Generally, bulk removal of water occurs as a result of certain man-made diversions, such as trucks, tanker ships, or pipelines.[247] It is not referring to a situation where water is being intentionally

238 Shawn McCarthy, Kelly Cryderman & Jeffery Jones, "In Alberta, fresh optimism for keystone after pivotal U.S. review" *The Globe and Mail* (31 January 2014), online: <www.globeinvestor.com/servlet/WireFeedRedirect?cf=GlobeInvestor/config&vg=&date=20140131&archive=rtgam&slug=escenic_16632806>.

239 US, Department of State Bureau of Oceans and International Environmental and Scientific Affairs, *Final Supplemental Environmental Impact Statement for the Keystone XL Project: Executive Summary, January 2014* (Washington, DC: US Department of State, 2014), online: <keystonepipeline-xl.state.gov/documents/organization/221135.pdf> [US State Report].

240 *Ibid* at ES-9.

241 *Ibid* at ES-17.

242 "New Keystone XL Pipeline Application," online: US Department of State <www.keystone pipeline-xl.state.gov/>; see also, "Keystone XL gets environmental OK from U.S. State Dept." *CBC News* (31 January 2014), online: <www.cbc.ca/news/business/keystone-xl-gets-environmental-ok-from-u-s-state-dept-1.2518271>.

243 Shawn McCarthy, "U.S.once again delays decision on Keystone XL pipeline," *The Globe and Mail* (18 April 2014), online: <www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/us-once-again-delays-decision-on-keystone-xl-pipeline/article18066497/>.

244 *Ibid*.

245 RSC 1985, c I-17, as amended by *Transboundary Waters Protection Act*, SC 2013, c 12.

246 See *Transboundary Waters Protection Act*, *ibid*, s 13(0.1).

247 "Prohibition of Bulk Water Removal," online: Environment Canada <www.ec.gc.ca/eau-water/default.asp?lang=En&n=1356EC91-1>.

shipped to other countries for profit, but is a consequence of other activities, such as those previously mentioned.[248] The bulk removal of water does not necessarily mean that the water is being transferred out of the country, but refers to a situation where the water is being transferred away from its basin of origin.[249]

For the purposes of the *International Boundary Waters Treaty Act*, the removal of bulk water is deemed to affect the natural level or flow of those waters on the other side of the international boundary.[250] There are exceptions in respect of transboundary waters that are used in a vehicle as ballast, for the operation of the vehicle, or for people, animals, or goods on or in the vehicle, as well as for non-commercial projects on a short-term basis, firefighting, or humanitarian purposes.[251]

An administration and enforcement section was also added into the *International Boundary Waters Treaty Act*. Pursuant to section 20.2, an inspector has the power to enter any place where such inspector has reasonable grounds to believe an activity regulated by this Act is taking place.[252] Upon entry, the inspector has the power to examine anything in the place, use any means of communication in the place, use any computer system, or examine any data in the place, remove anything from the place for examination or copying, direct any person to put any machinery, vehicle, or equipment in the place into operation or to cease operating it, prohibit or limit access to the place, and take samples or conduct tests on anything in the place.[253] In addition, an analyst may accompany the inspector, who may take samples and perform tests in any manner considered appropriate.[254]

2. *ADMINISTRATIVE MONETARY PENALTIES REGULATIONS (NATIONAL ENERGY BOARD)*

As part of the *Jobs, Growth and Long-term Prosperity Act*[255] that came into force in 2012, the *National Energy Board Act*, was amended to provide the National Energy Board (NEB) with the authority to issue administrative monetary penalties under the *Administrative Monetary Penalties Regulations (National Energy Board)*,[256] in order to promote compliance with the *NEB Act*.[257] Administrative penalties do not replace any of the NEB's other enforcement tools, and NEB staff maintain the discretion to apply the enforcement tool they deem most appropriate in the circumstances.[258]

In considering whether to issue an administrative penalty, the NEB will apply the following criteria:

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248 *Ibid*.
249 *Ibid*.
250 *Supra* note 245, s 13(3).
251 *Ibid*, s 13(4).
252 *Ibid*, s 20.2(1).
253 *Ibid*, s 20.2(2).
254 *Ibid*, s 20.3.
255 SC 2012, c 19.
256 SOR/2013-138 [*NEB Penalty Regulation*].
257 *Supra* note 70 , ss 134-154.
258 National Energy Board, *Administrative Monetary Penalties Process Guide*, (Calgary: National Energy Board, 2013) at 1 [*NEB Penalty Process Guide*].

- whether compliance has been obtained using other enforcement tools;
- whether the non-compliance has caused harm;
- whether the non-compliance is likely to cause harm; and
- whether the situation is one where the issuance of an administrative penalty is likely the best way to obtain compliance or deter future non-compliances.[259]

Any contravention of the *NEB Act*, or failure to comply with any term or condition of any certificate, licence, permit, leave, or exemption granted under the *NEB Act*, may result in an administrative penalty being issued.[260] Each day that a violation continues is considered a separate violation.[261] The amounts discussed below are in reference to the penalties imposable per day.

The amount of the administrative penalty in each case is determined by consulting the table found in Schedule 2 of the *NEB Penalty Regulation*.[262] There are two types of violations, Type A and Type B. Penalties for Type A violations range from $250 to $3,000 for individuals, and from $1,000 to $12,000 for any other person. Type B penalties range from $1,000 to $25,000 for individuals, and from $4,000 to $100,000 for any other person.[263] There is also a table found in section 4(2) which lists a variety of criteria and its effect on the determination of the final gravity level of the violation. Generally, aggravating factors increase the final gravity level, while mitigating factors decrease it.[264]

When an administrative penalty is issued, the NEB will serve notice on the company, third party, or individual.[265] The party receiving the notice of violation may either pay the administrative penalty, or request it be reviewed by the NEB Board, which will then issue a decision with reasons.[266] Regardless of whether a notice of violation is paid immediately or reviewed by the NEB Board, the notice of violation will be published on the NEB's website.[267]

3. *FISHERIES ACT*

In late November 2013, amendments to the fisheries protection provisions of the *Fisheries Act*[268] came into force. The prohibition found in section 35 of the *Fisheries Act* now reads "[n]o person shall carry on any work, undertaking or activity that results in serious harm to fish that are part of a commercial, recreational or Aboriginal fishery, or to fish that support such a fishery,"[269] whereas it used to apply in regard to "harmful alteration or disruption, or

259 *Ibid* at 3.
260 *NEB Penalties Regulation*, *supra* note 256, s 2.
261 *NEB Act*, *supra* note 70, s 141.
262 *Supra* note 256, s 4(1).
263 *Ibid*, Schedule 2.
264 *Ibid*, s 4(2).
265 *NEB Penalty Process Guide*, *supra* note 258 at 5.
266 *Ibid* at 8.
267 *Ibid* at 10.
268 RSC 1985, c F-14.
269 *Ibid*, s 35.

the destruction, of fish habitat."[270] The prohibition has now been divided into three classifications of protected fish: commercial, recreational, and Aboriginal.

Serious harm to fish is described under the *Fisheries Act* as "the death of fish or any permanent alteration to, or destruction of, fish habitat."[271] The Department of Fisheries and Oceans Canada released a Fisheries Protection Policy Statement in late 2013, explaining that "permanent alteration" and "destruction" of fish habitat is to be considered in regards to the spatial scale, duration, or intensity for which fish can use the habitat for behaviours such as spawning, nursing, rearing, feeding, or migrating.[272]

Another change under the amendments to the *Fisheries Act* is the requirement for authorizations for any work, undertaking, or activity that results in serious harm to fish that fall within one of the three protected classifications.[273] Also released were the *Applications for Authorization under Paragraph 35(2)(b) of the Fisheries Act Regulations*,[274] which describe the requirements for seeking such an authorization. Aside from describing specific information that must be included in an application, an irrevocable letter of credit must be provided to cover the costs of implementing a plan to offset the destruction to fish habitat.[275] The Minister has 90 days to issue a decision on the authorization.[276]

In addition, the maximum penalty for individuals who contravene section 35(1) has been raised to $1 million, with a minimum of $15,000, and for corporations to a maximum $6 million and minimum of $500,000.[277]

4. *REGULATION DESIGNATING PHYSICAL ACTIVITIES*

Under the *CEAA, 2012*,[278] certain projects are deemed to be "designated projects" that require environmental assessments.[279] A list of these projects is found in the *Regulations Designating Physical Activities*,[280] amended in 2013 by the *Regulations Amending the Regulations Designating Physical Activities*.[281]

Of note to the oil and gas industry, a newly designated activity is the expansion of an oil sands mine that would result in an increase in the area of mine operations of 50 percent or more and a total bitumen production capacity of 10,000 cubic metres per day or more.[282] Also added to the list is the drilling, testing, completion, suspension, and abandonment of exploratory wells prescribed by certain licences in relation to offshore exploration,[283] as well

270 *Ibid* as it appeared 13 November 2013. The previous version of the *Fisheries Act* can be found online: <laws-lois.justice.gc.ca/eng/acts/f-14/20120629/P1TT3xt3.html>.
271 *Ibid*, s 2(2).
272 Fisheries and Oceans Canada, *Fisheries Protection Policy Statement:October 2013* (Ottawa: Ecosystem Programs Policy, 2013) at 13.
273 *Supra* note 268, s 35(2).
274 SOR/2013-191.
275 *Ibid*, s 3(1).
276 *Ibid*, s 7.
277 *Fisheries Act*, *supra* note 268, s 40.
278 *Supra* note 84.
279 *Ibid*, s 32.
280 SOR/2012-147.
281 SOR/2013-186
282 *Regulations Designating Physical Activities*, *supra* note 280, Schedule, s 9.
283 *Ibid*, Schedule, s 10.

as the decommissioning and abandonment of existing offshore floating or fixed platforms, vessels or artificial islands used for the production of oil and gas.[284] The threshold for NEB-regulated pipelines has also been reduced, from 75 kilometers on a new right-of-way to 40 kilometers of new pipe, regardless of whether it is on a new right-of-way.[285]

The production thresholds resulting in designation have also been increased for certain activities, from 35 percent to 50 percent production capacity. Examples include tidal power generating facilities,[286] existing dams or dykes (35 percent to 50 percent increase in total surface area), expansions of oil refineries, liquid petroleum production facilities, sour gas processing facilities, or petroleum storage facilities,[287] and the expansion of hazardous waste disposal facilities.[288] The threshold for LNG storage facilities has also been increased to a processing capacity of 3,000 tonnes per day or more, or a liquefied natural gas storage capacity of 55,000 tonnes or more.[289]

Designations that have been removed include water extraction facilities, expansions of heavy oil or oil sands processing facilities, developing an oil and gas pipeline more than 75 kilometres in length on a new right-of-way, and developing certain types of electrical transmission lines on a new right-of-way.

B. BRITISH COLUMBIA

1. *WATER SUSTAINABILITY ACT*

British Columbia's *Water Sustainability Act*[290] passed its third and final reading on 29 April 2014 and is intended to update and replace the current British Columbia *Water Act*.[291] However, the *WSA* will not come into force until spring 2015 when supporting regulations have been finalized.[292] The most significant aspect of the *WSA* is its regulation of groundwater in the province. Prior to the *WSA*, British Columbia was the only province in Canada without legislation to regulate groundwater use.[293] Groundwater will be regulated in a similar manner to surface water using a "first in time first in right" approach, giving priority to those who have an existing authorization to divert water from a given source.[294]

A notable aspect of the *WSA* is its recognition of the evolving nature of resource management. First, a key component of the *Act* is the development of "water sustainability plans" which can impact licences issued in perpetuity. These plans can be implemented by the Minister of the Environment at any time in order to prevent or address conflicts between

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284 *Ibid*, Schedule, s 12.
285 *Ibid*, Schedule, s 47; *c.f. ibid*, Schedule, s 38(a) as it appeared on 23 October 2013.
286 *Ibid*, Schedule, s 3.
287 *Ibid*, Schedule, s 15.
288 *Ibid*, Schedule, s 30.
289 *Ibid*, Schedule, s 14(d).
290 Bill 18, *Water Sustainability Act*, 2nd Sess, 40th Leg, British Columbia, 2014 (assented to 29 May 2014), SBC 2014, c 15 [*WSA*].
291 *Supra* note 16.
292 "Water Sustainability Act," online: British Columbia <engage.gov.bc.ca/watersustainabilityact/>.
293 Dan Fumano, "New water proposal out on Friday; Updating Act: This is a big deal," *The Province* (18 October 2013) A4.
294 *WSA*, *supra* note 290, s 22(1).

water users, risks to water quality, or risks to aquatic ecosystem health.[295] If a water sustainability plan is implemented for a particular region, the government is empowered to cancel or amend the terms and conditions of existing licences identified by the plan.[296] Second, the *Act* authorizes the government to review both existing and future licences every thirty years.[297] This allows government officials to review and amend the terms and conditions of licences for more efficient water use.[298] Factors that will be considered when reviewing licences include best available technology, best practices, effects of climate change, and the licensee's beneficial use of water.[299]

While the *WSA* covers a wide range of issues, one particular provision of the *Act* has significant implications for the energy sector. In British Columbia it was considered common practice for the Oil and Gas Commission to issue repeated short-term water approvals for use in hydraulic fracturing.[300] The practice has been criticized in the province and is the basis of the plaintiff's cause of action in the WCWC Petition, discussed above in Part II.B.1.i of this article.[301] However, section 10(3) of the new *WSA* appears to allow for a short-term water approval to be repeatedly issued:

> For certainty, a use approval may be issued authorizing a person to divert water from a source of water supply for a water use purpose in relation to an appurtenancy, if any, specified in the use approval, whether or not a use approval was previously issued authorizing the person to divert water from the same water source supply for the same water use purpose in relation to the same appurtenancy.[302]

C. ALBERTA

1. REGULATORY AND COURT DECISIONS

i. *Water Conservation Trust of Canada v. Director, Central Region, Operations Division, Alberta Environment and Sustainable Resource Development*[303]

The Water Conservation Trust of Canada (WCTC) filed an application for a water licence transfer under the Alberta *Water Act*.[304] The purpose of the transfer was habitat enhancement and water management. The application was rejected. ESRD claimed that only the Government of Alberta was entitled to hold a licence in support of water conservation.

WCTC appealed. It argued that it had applied for a water licence transfer for numerous reasons other than water conservation, including recreation and fish and wildlife management. The Environmental Appeals Board (the Board) heard the appeal. It held that

295 *Ibid*, s 65(1)(a)(i).
296 *Ibid*, s 79(1).
297 *Ibid*, s 23.
298 *Ibid*, s 23(7).
299 *Ibid*, s 23(6).
300 Dan Fumano, "Court to decide if gas firms circumvent B.C. water laws; Environment," *The Province* (17 March 2014) A6.
301 *Supra* note 15.
302 *Supra* note 290, s 10(3)
303 8 March 2013, 10-056-R, online: AEAB <www.eab.gov.ab.ca/> [*WCTC*].
304 RSA 2000, c W-3.

the primary purpose of the proposed transfer was to support water conservation, and not the ancillary objectives alleged by the applicant WCTC. It further held that a private person is not entitled to hold a water-conservation-objective licence.[305] While it supported the WCTC's goals, it held that it had no choice but to recommend that the Minister reject the WCTC's application for the transfer of a water licence.[306] On 17 September 2013, the Minister signed an order rejecting the proposed transfer.

ii. *Gull Lake Water Quality Management v. Director, Central Region, Operations Division, Alberta Environment and Sustainable Resource Development, re: Delta Land Co. Inc.*[307]

Delta Land Co. Inc. (Delta) applied for an approval under the Alberta *Water Act* to construct and maintain a marina. The marina included an inland marina connected by a channel to Gull Lake. It also applied for water licences to divert water for the purpose of a golf course at Gull Lake. ESRD approved Delta's applications. The Gull Lake Water Quality Management Society (the Society) appealed the approvals.

The Board held a hearing to determine whether to quash the approvals and water licences. It held that the environmental disturbances from the marina would cause greater harm to Gull Lake than had been claimed by Delta or the ESRD. The Board recommended that a condition be added to the approval requiring Delta to provide new information regarding the marina, and to monitor environmental disturbances as they occurred. It ordered a stay of the approval until such conditions were approved and implemented.[308] The Board did not disturb the ESRD recommendation with respect to the water licences.

D. ONTARIO

1. REGULATORY AND COURT DECISIONS

i. *Castonguay Blasting Ltd. v. Ontario (Environment)*[309]

In *Castonguay*, the appellant was hired to perform rock blasting operations for a highway-widening project commissioned by the Ontario Ministry of Transportation. An accident occurred during blasting, and rock debris (fly-rock) was thrown into the air. The fly-rock crashed through the roof of a nearby home, seriously damaged a vehicle, and left a significant amount of rock in the yard of the nearby home. While the appellant reported the incident to the Ministry of Transportation and the Ontario Ministry of Labour, they did not report the incident to the Ontario Ministry of the Environment (MOE). Accordingly, the Ontario MOE charged them with failing to report the "'discharge of a contaminant into the natural environment' to the [Ontario MOE] contrary to s. 15(1) of the *EPA*."[310]

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305 *WCTC, supra* note 303 at para 119.
306 *Ibid* at para 130.
307 3 October 2013, 12-019-021, 023-024, & 027-029-R, online: AEAB <www.eab.gov.ab.ca/>.
308 *Ibid* at paras 119-20.
309 2013 SCC 52, [2013] 3 SCR 323 [*Castonguay*].
310 *Ibid* at para 7.

Section 15(1) of the *EPA* states that:

> Every person who discharges a contaminant or causes or permits the discharge of a contaminant into the natural environment shall forthwith notify the Ministry if the discharge is out of the normal course of events, the discharge causes or is likely to cause an adverse effect and the person is not otherwise required to notify the Ministry under section 92.[311]

"Adverse effect" is also defined under the same *Act* as

> one or more of,
>
> (a) impairment of the quality of the natural environment for any use that can be made of it,
>
> (b) injury or damage to property or to plant or animal life,
>
> (c) harm or material discomfort to any person,
>
> (d) an adverse effect on the health of any person,
>
> (e) impairment of the safety of any person,
>
> (f) rendering any property or plant or animal life unfit for human use,
>
> (g) loss of enjoyment of normal use of property, and
>
> (h) interference with the normal conduct of business.[312]

The appellant had argued that while the above definition of "adverse effect" had "eight components," paragraph (a) acted as an "umbrella clause" that must be satisfied "before any of the other seven elements come into play."[313] The Court rejected this argument based on a plain reading of the definition, holding that "all eight branches of 'adverse effect' provide independent triggers for liability."[314]

The Court also took the opportunity to comment on how general environmental principles could be applied to the interpretation of environmental legislation. For example, the Court observed how "s. 15(1) is also consistent with the precautionary principle … by ensuring that the Ministry of the Environment is notified and has the ability to respond once there has been a discharge of a contaminant out of the normal course of events, without waiting for proof that the natural environment has, in fact, been impaired."[315] The Court also warned against restricting the scope of the definition of "adverse effect," noting that to do so "would

311 *Supra* note 91, s 15(1).
312 *Ibid*, s 1(1)
313 *Castonguay*, *supra* note 309 at para 16.
314 *Ibid* at para 30.
315 *Ibid* at para 20.

therefore also limit the scope of the *EPA*'s protective and preventative capacities and, consequently, the Ministry's ability to respond to the broad purposes of the statute."[316]

ii. *Kawartha Lakes (City) v. Gendron*[317]

In *Kawartha*, the appellant City of Kawartha Lakes had been ordered by the Ontario MOE to remediate the adverse effects on their property of an oil spill that occurred on an adjacent property. The Ontario MOE order was a "no fault order" made under section 157.1 of the *EPA*, which "did not require an assertion by the [Ontario] MOE of any fault on the part of the appellant."[318] On an appeal of the order to the Ontario Environment Review Tribunal (ERT), the ERT prevented the appellant from calling evidence to show who was at fault for the spill and this decision was upheld on appeal to the Ontario Divisional Court.[319]

At the Ontario Court of Appeal level, the appellants argued that the ERT's "procedural order excluding evidence that others were at fault for the spill denied it natural justice and prevented it from fully making its case that it should be relieved of the [Ontario MOE's] order because of the 'polluter pays' principle."[320] The Ontario Court of Appeal affirmed the decisions of the ERT and of the Ontario Divisional Court, holding that:

> evidence that others were at fault for the spill is irrelevant to whether the order against the appellant should be revoked. That order is a no fault order. It is not premised on a finding of fault on the part of the appellant but on the need to serve the environmental protection objective of the legislation.
>
> The tribunal had to determine whether revoking the Director's order would serve that objective. Deciding whether others are at fault for the spill is of no assistance in answering that question. Evidence of the fault of others says nothing about how the environment would be protected and the legislative objective served if the Director's order were revoked. Indeed, by inviting the Tribunal into a fault finding exercise, permitting the evidence might even impede answering the question in the timely way required by that legislative objective.[321]

iii. *Baker v. Ontario (Director, Ministry of the Environment)*[322]

This is a significant case regarding whether directors and officers of a corporation can be held personally liable for Ontario MOE remediation orders. The appellants were former directors and officers of Northstar Aerospace (Canada) Inc. (Northstar) who, in 2004, had discovered the presence of trichloroethylene on property owned by Northstar. While Northstar engaged in voluntary remediation of the property between 2004 and 2012, in early 2012 the Ontario MOE became concerned about the financial well-being of Northstar.[323] Accordingly, the Ontario MOE issued two "Director's Orders" which, among other things, ordered Northstar and its parent to ensure that remediation would continue "notwithstanding

316 *Ibid* at para 35.
317 2013 ONCA 310, 307 OAC 264 [*Kawartha*].
318 *Kawartha*, *ibid* at para 7; *EPA*, *supra* note 90.
319 *Ibid* at para 3.
320 *Ibid* at para 17.
321 *Ibid* at paras 19-20.
322 2013 ONSC 4142, [2013] OJ No 3145 (QL) [*Baker v MOE*].
323 *Ibid* at para 7.

the financial difficulties of both companies."[324] In response, both companies applied for, and received, protection under the *Companies' Creditors Arrangement Act*.[325] The *CCAA* court approved a sales process that would sell the majority of both companies' assets to a third party, leaving the companies with little to no assets.[326]

Despite the above, in late 2012 the Ontario MOE issued a Director's Order (in this section, the Order) against the former directors and officers of Northstar "requiring them to assume responsibility for the remediation activities…at an estimated cost…of about $1.4 million per year."[327] On appeal to the ERT, the former directors and officers requested a stay of the Order pending a determination of the appeal. The ERT rejected the stay request, holding that the appellants did not meet the three part test for the granting of a stay from the *RJR MacDonald* case.[328]

The former directors and officers both appealed and judicially reviewed the ERT's decision to the Ontario Divisional Court. The Ontario MOE argued that the appeal should be quashed on the basis that the Ontario *EPA* provided no right for the appeal of an interlocutory decision. The Court agreed with the Ontario MOE that the issue was an "interlocutory" one, holding that the ERT's stay order "does not finally dispose of any of the Appellants' rights in the proceedings it has pending before the Tribunal.… The order deals with a 'collateral' issue in the litigation, namely who should bear the costs of remediation pending the hearing of the appeal. As such, it is an interlocutory order."[329]

The Court also agreed that the wording of the appeal provisions of the *EPA* did not give an applicant the right to appeal an interlocutory stay decision of the ERT. The Court was concerned that broadening the right to appeal an ERT decision to include a stay decision might challenge the justifications for establishing a specialized tribunal in the first place, "namely, 'cheapness, expedition and expertise.'"[330]

The Court also rejected the application for judicial review of the stay decision, noting that "the Appellants have failed to avail themselves of all effective remedies that are available within the administrative process," including requesting the ERT to reconsider "all or part" of its decision or bringing a motion to stay the order in light of new evidence and arguments that were not before the ERT when it initially dealt with the stay motion.[331]

On 28 October 2013, the day before the ERT was to hear the appeal of the Order, the Ontario MOE and the former directors and officers of Northstar reached a $4.75 million settlement agreement.[332] Under the terms of the settlement, the MOE will assume the

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324 *Ibid* at para 8.
325 RSC 1985, c C-35 [*CCAA*].
326 *Baker v MOE*, *supra* note 322 at paras 10-12.
327 *Ibid* at para 14.
328 *Supra* note 112. The three part test is also described at note 112.
329 *Baker v MOE*, *supra* note 322 at para 32.
330 *Ibid* at 39, citing *Re Roosma and Ford Motor Co of Canada* (1988), 66 OR (2d) 18 at 24 (Div Ct).
331 *Baker v MOE*, *ibid* at paras 45-47.
332 Bill Jackson, "Northstar officials, MOE reach $4.75M remediation deal," *Cambridge Times* (28 October 2013), online: <www.cambridgetimes.ca/news-story/4179562-northstar-officials-moe-reach-4-75m-remediation-deal/>.

remediation work on the former Northstar property and will revoke the previously-issued Order against the former directors and officers of Northstar.[333]

XI. ABORIGINAL ISSUES

A. *GOVERNMENT OF ALBERTA'S POLICY ON CONSULTATION WITH FIRST NATIONS ON LAND AND RESOURCES MANAGEMENT, 2013*

On 16 August 2013, the Government of Alberta released *The Government of Alberta's Policy on Consultation with First Nations on Land and Resources Management, 2013*.[334] The stated purpose of the *Policy* is "to reconcile First Nations' constitutionally protected rights with other societal interests with a view to substantially address adverse impacts on Treaty rights and traditional uses through a meaningful consultation process."[335]

1. APPLICATION OF THE *POLICY*

The *Policy* applies to any strategic Crown decisions[336] and project-specific Crown decisions[337] that "may adversely impact the continued exercise of Treaty rights and traditional uses."[338] The *Policy* also contemplates the establishment of "consultation process agreements" between Alberta and individual First Nations that will clarify specific aspects of the consultation process.

2. CONSULTATION PROCESS UNDER THE *POLICY*

Concurrently with the releasing of the *Policy*, Alberta has drafted the *Government of Alberta's Corporate Guidelines for First Nations Consultation Activities* (*Corporate Guidelines*).[339] The *Corporate Guidelines* augment the *Policy* by developing specific standards for consultation activities to ensure that Alberta meets its constitutional duty to consult.

To facilitate consultation between First Nation groups and Alberta, Alberta also established the Alberta Consultation Office (the ACO), which reports to the Minister of Aboriginal Relations. Whenever a Crown decision is proposed that may require First Nations consultation, the ACO will conduct an initial assessment to determine:

- Whether the project requires consultation;

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333 *Ibid*.
334 Alberta, *The Government of Alberta's Policy on Consultation with First Nations on Land and Resources Management, 2013* (3 June 2013), online: Alberta Aboriginal Affairs <www.aboriginal.alberta.ca/documents/GoAPolicy-FNConsultation-2013.pdf> [*Policy*].
335 *Ibid* at 1.
336 Examples include the establishment of provincial regulations, policies, or plans that have the potential to adversely affect First Nations rights.
337 Examples include any decisions that relate to oil and gas, forestry, or other natural resource development approvals that have the potential to adversely affect First Nations rights.
338 *Policy*, *supra* note 334 at 2.
339 Alberta, *The Government of Alberta's Corporate Guidelines for First Nations Consultation Activities, 2013* (draft, 3 June 2013), online: Alberta Aboriginal Affairs <www.aboriginal.alberta.ca/documents/GoACorpGuidelines-FNConsultation-2013.pdf> [*Corporate Guidelines*].

- Which First Nations to notify;
- What level of consultation is necessary in the circumstances; and
- Whether or not to delegate procedural aspects of consultation to project proponents.[340]

The *Corporate Guidelines* establish a draft “consultation matrix” that assists in this assessment. The matrix allows the ACO to assign one of three “assessment levels” to a project, depending on the project’s impact on First Nations treaty rights and traditional uses of the land.[341] A Level 1 assessment will be made where a project is expected to have no adverse impact on Treaty rights and traditional uses and no consultation will be necessary.[342] A Level 2 assessment will be made where a project is expected to have a low adverse impact and some of the required consultation will be delegated to project components. A Level 3 assessment will be made where a project may have a significant adverse impact and consultation must be directly carried out by Alberta.[343]

3. CURRENT STATUS OF THE *POLICY* AND THE ACO

The ACO became effective as of 1 November 2013.[344] However, as the ACO is still undergoing an internal re-organization, any First Nations consultation applications will continue to be handled under *The Government of Alberta’s First Nations Consultation Policy on Land Management and Resource Development, 2005*,[345] which includes related guidelines originally published in 2006. While the ACO had stated that it expected to become fully operational in the spring of 2014, there is no indication of when the ACO will be fully implemented. Similarly, the *Policy* will not be implemented until “operational guidelines are developed to support the Policy,”[346] including the finalization of the *Corporate Guidelines*.

B. ***FORT MCKAY FIRST NATION V. ALBERTA ENERGY REGULATOR***[347]

1. BACKGROUND

In *Fort McKay*, the Alberta Court of Appeal granted the Fort McKay First Nation (FMFN) leave to appeal the decisions of the ERCB and the AER approving the development of the bitumen recovery scheme of Brion Energy Corporation (Brion, formerly known as Dover Operating Corp.). While Brion and the FMFN reached a settlement agreement to discontinue

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340 *Ibid* at 1.
341 *Ibid* at 2.
342 “First Nation Consultation Matrix,” online: Alberta Aboriginal Affairs <www.aboriginal.alberta.ca/documents/GoAMatrix-FNConsultation-2013.pdf>.
343 *Ibid*.
344 “First Nations Consultation Updates,” online: Alberta Environment and Sustainable Resource Development <esrd.alberta.ca/lands-forests/first-nations-consultation/first-nations-consultation-updates.aspx>.
345 Alberta, *The Government of Alberta’s First Nations Consultation Policy on Land Management and Resource Development* (16 May 2005), online: Alberta Aboriginal Affairs <www.aboriginal.alberta.ca/documents/Policy_APPROVED-May16.pdf>.
346 “First Nations Consultation Updates,” *supra* note 344.
347 2013 ABCA 355, [2013] AJ No 1108 (QL) [*Fort McKay*].

the appeal on 21 February 2014,[348] the leave to appeal application highlighted a number of live issues that could implicate future energy projects in Alberta.

2. FACTS

Brion applied to the Energy Resources Conservation Board (the ERCB, the predecessor entity to the AER) for approval of the project pursuant to the *Oil Sands Conservation Act*[349] and related statutes. Subsequent to the application being filed, the FMFN gave the ERCB notice that it intended to raise two constitutional issues at the hearing for the project: (1) whether the approval of the project would constitute a prima facie infringement of the FMFN's treaty rights; and (2) whether the Crown adequately discharged its duty to consult and accommodate the FMFN for the adverse effects of the project.[350]

Prior to the hearing, the ERCB advised the FMFN that it "does not possess the jurisdiction to consider"[351] the constitutional questions because the questions did not fall within the types of constitutional questions it was able to consider under the *Administrative Procedures and Jurisdiction Act*.[352] On 6 August 2013, the AER (who had assumed the ERCB's powers as of June 17, 2013) approved Brion's application and again affirmed the decision of the ERCB to not consider the FMFN's constitutional questions. The AER also cited section 21 of the new *REDA* in support of its position, which states that the AER has "no jurisdiction with respect to assessing the adequacy of Crown consultation."[353] The FMFN applied for leave to appeal the decisions of both the ERCB and the AER.

3. DECISION

The FMFN applied for leave to appeal on four issues and the Alberta Court of Appeal granted leave to appeal on the following two issues:

> (a) Did the Energy Resources Conservation Board or the Alberta Energy Regulator commit any reviewable error of law or jurisdiction in the assessment of the type of constitutional questions they could or should consider under their general jurisdiction over issues of law, or the *Administrative Procedures and Jurisdiction Act*?, and if so
>
> (b) Did any such reviewable error in defining the scope of the constitutional issues have any reviewable impact on the ultimate approval of the project by the Alberta Energy Regulator?[354]

Brion had argued that the FMFN's leave to appeal application on the AER's interlocutory decision relating to the scope of the constitutional issues that would be considered was filed out of time.[355] Brion noted that the *Responsible Energy Development Act General Regulation*

348 See Dan Healing, "Brion Energy reaches oilsands deal with Fort McKay First Nation," *Calgary Herald* (21 February 2014), online: <www.calgaryherald.com/business/Brion+Energy+reaches+oilsands+deal+with+Fort+McKay+First+Nation/9536166/story.html>.
349 RSA 2000, c O-7.
350 *Fort McKay*, *supra* note 347 at para 3.
351 *Ibid*.
352 RSA 2000, c A-3.
353 *REDA*, *supra* note 23, s 21.
354 *Fort McKay*, *supra* note 347 at para 20.
355 *Ibid* at para 10.

requires that any leave to appeal application must be filed within one month of when the decision was made[356] and since the initial "constitutional decision" was initially issued by the ERCB in April 2013, the FMFN was out of time.

The Court of Appeal rejected Brion's argument, noting that "[c]omplex project approvals, such as the one in issue here, often lend themselves to being decided in stages. There might be a number of interlocutory decisions, on discrete issues, leading up to an eventual decision on the project approval itself."[357] Accordingly, "[t]he better approach is, as a general rule, to regard the final decision as incorporating by reference all of the interlocutory decisions that preceded it, and then to apply for leave to appeal on any issues that remain at the end of the proceedings."[358]

The Court also discussed the fact that the original constitutional questions that the FMFN posed to the AER "would have required the Regulator to inquire into the applicant's treaty rights, and then the legislative competence of the province, both things which the Regulator declined to do."[359] Accordingly, the Court held that "[o]n that basis, there is a live issue respecting the Regulator's interpretation of its power to decide constitutional issues under the *Administrative Procedures and Jurisdiction Act*. The issue is of general importance, and leave to appeal is justified."[360]

X. OTHER ISSUES

A. FEDERAL

1. *INVESTMENT CANADA ACT*

In June 2013 the federal government proclaimed into force certain amendments to the *Investment Canada Act*.[361] Of note, the definition of "state-owned enterprise" (SOE) was broadened to include entities controlled or influenced, directly or indirectly, by foreign governments or agencies.[362]

There were also amendments to provisions dealing with deeming entities to be either Canadian-controlled or SOEs. One such change is that if it can be established that a trust is not controlled in fact through the ownership of its voting interests, then it will be considered to be Canadian-controlled if two-thirds of its trustees are Canadian.[363] Another notable change is that even if an entity qualifies as Canadian-controlled, the Minister may nevertheless determine that it is not Canadian-controlled if the Minister deems that the entity is controlled in fact by an SOE.[364] The Minister also has the power to determine whether or

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356 Alta Reg 90/2013, s 5.
357 *Fort McKay*, *supra* note 347 at para 11.
358 *Ibid* at para 12.
359 *Ibid* at para 13.
360 *Ibid* at para 14.
361 RSC 1985, c 28 (1st Supp).
362 *Ibid*, s 3.
363 *Ibid*, s 26(2).
364 *Ibid*, s 26(2.31).

not there has been an acquisition of control by an SOE, and to request information in order to make these determinations.[365]

2. *SPECIES AT RISK ACT — EMERGENCY ORDER FOR THE PROTECTION OF THE GREATER SAGE-GROUSE*

i. Background

On 4 December 2013, the Government of Canada published the *Emergency Order for the Protection of the Greater Sage-Grouse*[366] (in this section, the *Order*) pursuant to section 80(1) of the *Species at Risk Act*.[367] The purpose of the *Order* is to protect the greater sage-grouse species, of which there were estimated in 2012 to be between 93 and 138 adult birds remaining in Canada.[368] The *Order* will cover approximately 1700 square kilometres stretching across Alberta and Saskatchewan, a significant portion of which are provincial Crown lands.[369] Accordingly, any future orders issued by the federal government could potentially have massive implications for energy projects that fall within the scope of such orders.

ii. Legal Framework for the *Order*

Sections 80(1) and (2) of *SARA* gives the federal Cabinet the power to issue an emergency order on the recommendation of the federal Minister of the Environment, so long as "he or she is of the opinion that the species faces imminent threats to its survival or recovery."[370] Section 80(4) of *SARA* defines the specific protection measures that an order may include. The Order was issued under section 80(4)(c), which states that an emergency order issued for species other than "aquatic species" and "migratory birds protected by the *Migratory Birds Convention Act, 1994*" may:

> (i) on federal land, in the exclusive economic zone of Canada or on the continental shelf of Canada,
>
> (A) identify habitat that is necessary for the survival or recovery of the species in the area to which the emergency order relates, and
>
> (B) include provisions requiring the doing of things that protect the species and that habitat and provisions prohibiting activities that may adversely affect the species and that habitat, and
>
> *(ii) on land other than land referred to in subparagraph (i),*
>
> (A) identify habitat that is necessary for the survival or recovery of the species in the area to which the emergency order relates, and

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365 *Ibid*, ss 28(6.1), 37.
366 SOR/2013-202 [*Order*].
367 SC 2002, c 29, s 80(1) [*SARA*].
368 Environment Canada, News Release, "Working Together to Protect the Greater Sage-Grouse" (23 January 2014), online: <www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=DAF1 BEAD-78B5-419D-8FE8-C80BE918A19B>.
369 *Ibid*.
370 *SARA*, *supra* note 367, s 80(2).

(B) include provisions prohibiting activities that may adversely affect the species and that habitat.[371]

The emphasized portion of section 80(4)(c) above gives the *Order* the power to encroach on provincially-owned lands, in addition to federally-owned lands. The *Order* generally prohibits the killing or moving of sage-brush or grasses that are important to the sage-grouse's survival, the construction or installation of new fencing (except where the fencing complies with the exceptions in the *Order*), constructing any structure that emits chronic noise in a manner described by the *Order*, the construction or the widening of a road, or installing a structure, machine or pole exceeding 1.2 metres in height.[372] The *Order* also carves out a number of exceptions to the above prohibitions, including the fact that the prohibitions do not apply within 100 metres of a residential building or building used for agricultural operation purposes that existed as of the date of the *Order*.[373]

As a final note, while there are no existing gas wells that will be affected by the *Order*, future development in this area "could nonetheless take place in such a way as to not contravene the Order (e.g. via horizontal access of the resource) without significantly increasing the cost."[374]

3. NATIONAL ENERGY BOARD DECISIONS

i. *Re Westcoast Energy Inc., carrying on Business as Spectra Energy Transmission (Westcoast) — Application for Access to Certain Lands dated 7 June 2013, Applications to Review Board Orders for Access to Certain Lands Issued 8 August 2013*[375]

Westcoast Energy Inc., carrying on business as Spectra Energy Transmission (Westcoast), had applied to the NEB under sections 11, 12, 13 and sections 73(g) and 73(i) of the *NEB Act*, to gain access to lands for a pipeline replacement project in British Columbia. Sections 73(g) and 73(i) of the *NEB Act* state that "[a] company may, for the purposes of its undertaking … alter, repair or discontinue the works mentioned in this section, or any of them, and substitute others in their stead; … [and] do all other acts necessary for the construction, maintenance and operation of its pipeline."[376] The NEB granted Westcoast these orders in mid-2013.

On 10 October 2013, a number of parties affected by the project applied to the NEB for a review of the NEB orders and, accordingly, the NEB established a process to determine whether there was "doubt as to the correctness of the [NEB's] decision to grant the … orders."[377] The affected parties argued that: (1) before Westcoast could perform any actual

371 *Ibid*, s 80(4) [emphasis added].
372 *Order*, *supra* note 366, s 3.
373 *Ibid*, s 4(3).
374 "Emergency Order for the Protection of the Greater Sage-Grouse: Regulatory Impact Analysis Statement," online: Species at Risk Public Registry <www.registrelep-sararegistry.gc.ca/ default.asp?lang=En&n=F25868B7-1>.
375 31 January 2014, GH-3-2008, online: NEB <www.neb-one.gc.ca> [*Westcoast Board Decision*].
376 *NEB Act*, *supra* note 70, s 73.
377 *Westcoast Board Decision*, *supra* note 375 at 2.

work, a written agreement addressing compensation had to be entered into; and (2) that the NEB orders were made without the "statutory and procedural requirements" of sections 104 and 105 of the *NEB Act*, which allow the NEB to issue a right of entry order for a parcel of land so long as particular conditions are met.[378] In response, Westcoast argued that it had registered existing easement agreements against the lands and that sections 104 and 105 of the *NEB Act* were not applicable to such situations.

The NEB accepted the arguments of the affected landowners and rescinded the prior orders made in favour of Westcoast. The NEB held that, if Westcoast in fact had valid easement agreements and had "obtained the legal interests and rights in lands that it needs to exercise its powers under sections 73(g) and 73(i) of the NEB Act," there was no need for Westcoast to apply for right of entry orders.[379] The NEB also held that it

> should not have relied upon sections 11, 12 and 13, and paragraphs 73(g) and 73(i), to grant Westcoast access to the lands. That is not the intended purpose of these provisions. Part V of the NEB Act provides a legal framework for land acquisition agreements and orders for immediate right of entry. When a company has obtained the necessary legal interests and rights in lands, it is the company's responsibility to enforce those interests and rights through the use of section 17 of the NEB Act, where appropriate, or by seeking remedies in the appropriate court of competent jurisdiction.[380]

ii. *Re Application for Review and Variance of Application (Review Application)*[381]

On 27 March 2013, the NEB released their decision on TransCanada PipeLines Limited's (TransCanada) Mainline pipeline system restructuring application.[382] On 1 May 2013, TransCanada filed an application for review requesting that the NEB review and vary their decision with respect to the restructuring application. To meet the threshold for the Board to potentially vary a prior decision, the applicant must "raise a doubt as to the correctness of the [NEB's] decision or order."[383] The NEB rejected TransCanada's application for review, because TransCanada did not raise a doubt as to the correctness of the NEB's decision.

TransCanada made three main arguments: (1) that the NEB breached its duty to be fair "because the Decision implements a tolling model that in its totality was not disclosed on the record of the proceeding";[384] (2) that the NEB made incorrect findings of fact; and (3) that new facts arose since the close of the original proceeding.[385] The NEB rejected all three of these arguments.

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378 *Ibid* at 2.
379 *Ibid* at 3.
380 *Ibid*.
381 22 July 2013, A53024, online: NEB <www.neb-one.gc.ca> [*Review Application*].
382 See *Re Hearing Order RH003-2011 – TransCanada Pipelines Limited (TransCanada), NOVA Gas Transmission Ltd (NGTL) and Foothills Pipe Lines Ltd (Foothills) Application dated 1 September 2011 for Approval of the Business and Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013 – Toll Order* (27 March 2013) A51040, online: NEB <www.neb-one-gc.ca>.
383 *Review Application*, *supra* note 381 at 3.
384 *Ibid* at 4.
385 *Ibid* at 3.

With respect to the duty to be fair, the NEB noted that their decision was based on a toll proposal made by the Canadian Association of Petroleum Producers (CAPP) and that "[a]ll findings made in the Decision, including findings that differ from the assumptions underlying CAPP's toll proposal, were based on the record."[386] With respect to TransCanada's second argument, the NEB held that they had not made any incorrect findings of fact and that a difference of opinion is "not a fact."[387] Finally, the NEB found that TransCanada's alleged "new facts" did not raise a doubt as to the correctness of their original decision.[388]

iii. *Enbridge Pipelines Inc. — Application dated 29 November 2012 for the Line 9B Reversal and Line 9 Capacity Expansion Project*[389]

On 6 March 2014, the NEB approved Enbridge Pipelines Inc.'s (Enbridge) application to reverse a segment of Line 9 (Line 9B) between North Westover, Ontario and Montreal, Quebec and to expand the total pipeline capacity from Sarnia, Ontario to Montreal, Quebec. This is a final decision that does not require approval of the federal Governor in Council.[390] The NEB determined that, subject to 30 conditions it placed on the project, approving the project was in the public interest and consistent with the relevant parts of the *NEB Act*.[391] The decision also allows Enbridge to now transport heavy crude oil on the pipeline.

A number of the conditions placed on Enbridge's NEB approval include requirements that, prior to construction, the NEB establish a "Commitments Tracking Table" on its website that lists all commitments made by Enbridge in its application and to continuously update the status of these commitments.[392] Many also include requirements that Enbridge file documentation with the NEB relating to the safety and integrity of the pipeline prior to requesting leave to open the line and a number of reports following the line going into operation, as well as certain ongoing reporting requirements for the line.[393]

B. ALBERTA

1. *OCCUPATIONAL HEALTH AND SAFETY ACT*[394]

In October 2013, further changes were made to the *OHSA* to supplement changes made in 2012. Of particular note is the introduction of administrative penalties for breaches of the *OHSA*, the *Occupational Health and Safety Code 2009*[395] and the *Occupational Health and Safety Regulation*.[396] These penalties may be issued to contractors, employers, prime contractors, suppliers, and workers.[397]

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386 *Ibid* at 2.
387 *Ibid* at 11.
388 *Ibid* at 11-12.
389 6 March 2014, A59174, online: NEB <www.neb-one.gc.ca> [*Enbridge Pipelines*].
390 "Enbridge Pipelines Inc. – Line 9B Reversal and Line 9 Capacity Expansion Project — Frequently Asked Questions," online: NEB <www.neb-one.gc.ca/pplctnflng/mjrpp/ln9brvrsl/ln9brvrslrfdfq-eng.html>.
391 *Enbridge Pipelines*, *supra* note 389 at 4.
392 *Ibid* at 131.
393 *Ibid* at 132.
394 RSA 2000, c O-2 [*OHSA*].
395 Alta Reg 87/2009, online: <work.alberta.ca/documents/whs-leg_ohsc_2009.pdf>.
396 Alta Reg 62/2003.
397 *OHSA*, *supra* note 394, s 40.3.

Under the new administrative penalty regime, for a first offence the maximum fine is $500,000, with a further fine of not more than $30,000 for each day that the offence continues.[398] Imprisonment for up to 6 months remains an enforcement option.[399] For offences that are not a first offence, the maximum fine is $1 million, with further fines of up to $60,000 for each day that the offence continues.[400] In addition, if a person fails to comply with an order in regards to the health or safety of a worker, he or she may be fined up to $1 million, liable to imprisonment for up to 12 months, or both.[401] Knowingly giving false information or making a false statement to an officer may also result in a fine of up to $1,000, a term of imprisonment of up to 6 months, or both.[402] A party given an administrative penalty has the option to appeal it to the OHS Council.[403] A two-year limitation period for prosecution under the *OHSA* has also been introduced.[404]

In addition, on 1 January 2014 amendments were made to the *Provincial Offences Procedure Act Procedures Regulation*[405] to allow for tickets in amounts of up to $500 to be issued to companies and individuals in regards to certain violations of the *Occupational Health and Safety Code 2009* and the *Occupational Health and Safety Regulation*. For example, tickets may be issued for employers in regards to protective equipment, biological hazards, smoking in prohibited areas, fire prevention, equipment safety and standards, and the safety of stairways and ladders.[406] These tickets are given "on the spot," and are not criminal in nature.[407]

2. *BUILDING NEW PETROLEUM MARKETS ACT*

On 10 January 2014, Bill 34, the *Building New Petroleum Markets Act*,[408] was proclaimed in force. The dual purpose of the *BNPMA* is not only to expand the contracting powers of the Alberta Petroleum Marketing Commission (Commission), but also to increase the ability of the Minister of Energy to issue directives and otherwise set strategic priorities for the board of directors of the Commission.

The Commission, originally created in 1974, is the provincial Crown corporation responsible for marketing hydrocarbons the province receives as in-kind royalty payments. The Commission saw its role expanded just two years ago to facilitate the development and implementation of the province's new Bitumen Royalty-in-Kind (BRIK) program.[409] The flagship project for the BRIK program was the 30-year processing agreement signed with North West Redwater Partnership on 16 February 2011, whereby the province agreed to supply 75 percent of the bitumen feedstock volume to the Sturgeon Refinery (the Northwest

398 *Ibid*, s 41(1)(i).
399 *Ibid*, s 41(1)(ii).
400 *Ibid*, s 41(1)(b)(i).
401 *Ibid*, s 41(2).
402 *Ibid*, s 41(3).
403 *Ibid*, s 16(1).
404 *Ibid*, s 41(4).
405 Alta Reg 233/1989, as amended by Alta Reg 140/2014.
406 *Ibid*, Schedule 2, part 13.1-13.2.
407 *Ibid*, s 12.
408 Bill 34, 1st Sess, 28th Leg, Alberta, 2013 (assented to 11 December 2013), SA 2013, c 16, proclaimed in force 31 January 2014, (2014) A Gaz I, 110:2 [*BNPMA*].
409 See "Alberta Petroleum Marketing Commission (APMC)," online: Alberta Energy <www.energy.alberta.ca/includes/3435.asp>.

Upgrader) currently under construction 45 kilometres northwest of Edmonton.[410] In addition, just prior to the tabling of Bill 34, on 28 October 2013 the province announced the Commission had signed an Expression of Intent with Indian Oil Corporation Limited to supply 100,000 barrels per day of bitumen on the Energy East pipeline.[411]

The *BNPMA* amends both the *Petroleum Marketing Act*,[412] and the *Natural Gas Marketing Act*.[413] The most important amendment appears to be the broad authority added to section 15 of the *PMA*. Whereas previously the Commission's power was limited primarily to accepting delivery of and dealing with the Crown's royalty share, the Commission now has the ability to "*engage in other hydrocarbon-related activities* in a manner that is, in the Commission's opinion, in the public interest of Alberta."[414] Another important amendment is the ability of the Minister of Energy to issue directives that the Commission, its board of directors, or both, must follow in carrying out their statutory powers and duties.[415] The board must also ensure that such directives are "implemented in a prompt and efficient manner" and in accordance with the newly-added section 6.1, which provides that the duties of the directors to (1) "act honestly and in good faith and with a view to the best interests of the Commission," and (2) "exercise the care, diligence and skill that a reasonable and prudent person would exercise in comparable circumstances."[416]

Other changes include the creation of a larger board of directors (whereas previously the maximum was not more than three, now there will not be more than seven)[417] and a broader ability to guarantee obligations, enter into loans, and enter into other investment transactions.[418] For example, section 12.1(3) of the *PMA* reads as follows:

> The Commission may, with the approval of the Lieutenant Governor in Council,
>
> (a) directly or indirectly purchase shares,
>
> (b) make a loan of money or acquire an existing loan of money, or
>
> (c) in a transaction involving the payment of any money, enter into a joint venture or partnership
>
> for the purposes of fulfilling its responsibilities under section 15.[419]

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410 North West Redwater Partnership is a partnership between North West Upgrading Inc. and Canadian Natural Upgrading Limited, a wholly-owned subsidiary of Canadian Natural Resources Limited. More details on the project can be found at "The Sturgeon Refinery: Fueling the Future," online: Alberta Energy <www.energy.alberta.ca/3444.asp>.

411 "Alberta Petroleum Marketing Commission (APMC) News," online: Alberta Energy <www.energy.alberta.ca/NaturalGas/3610.asp>.

412 RSA 2000, c P-10 [*PMA*].

413 RSA 2000, c N-1 [*NGMA*].

414 *PMA*, *supra* note 412, s 15(c) [emphasis added].

415 *Ibid*, s 12.2(1).

416 *Ibid*, ss 6.1, 12.2(3). Section 6.1 of the *PMA* uses identical language to that of section 122 of the *Business Corporations Act*, RSA 2000, c B-9, which sets out the duty of loyalty and duty of good faith for directors and officers in corporate law. The new section 6.2 of the *PMA* also expressly states that section 120 of the *Business Corporations Act*, which relates to material contract disclosure, applies to the directors and officers of the Commission.

417 *Ibid*, s 2(1.2).

418 *Ibid*, ss 12, 12.1.

419 *Ibid*, s 12.1(3).

Finally, the provincial government has stated publicly that the amendments introduced by the *BNPMA* are intended to build on the momentum of the Sturgeon Refinery and Energy East initiatives. When Bill 34 was originally tabled in the Legislature, on 6 November 2013, Energy Minister Ken Hughes had said that

> [the *BNPMA*] *will be the vehicle the government uses for strategic initiatives to ensure we get access to markets and add value where there is a direct role of the province*.
>
> …
>
> We would look at projects that need strategic support from the province to enable them to happen. That is what we did with North West, and with Energy East, when the proponents came to us and said they didn't know whether they had enough support from shippers to go all the way to Saint John, N.B.[420]

The impact of the amendments have yet to be seen, but it is already clear that the province has made room for the Commission to have an expanded role in private contracting for the Crown's royalties-in-kind.

3. ALBERTA UTILITIES COMMISSION

i. AUC Decision 2013-435: *Distribution Performance-Based Regulation 2013 Capital Tracker Applications*[421]

Five regulated utilities filed capital tracker applications with the Alberta Utilities Commission (AUC), under the performance-based rate regulation (PBR) framework. PBR, which was adopted by the AUC in 2012, is an alternative to the traditional rate-base or rate-of-return framework. The "capital tracker" is a supplemental mechanism for regulated utilities under the PBR to fund certain capital costs, through which the revenue requirement necessary to pay those costs is collected from ratepayers by way of a "K factor."[422] Capital costs recoverable by way of a capital tracker must:

1. Be outside of the normal course of the utility's ongoing operations;

2. Be for replacement of existing capital assets or otherwise required by an external party; and

3. Have a material effect on the utility's finances.[423]

Previous proceedings before the AUC approved capital tracker placeholders equal to 60 percent of the applied-for amounts. The AUC indicated that its holding in the instant decision would be trued-up with those amounts in future proceedings.[424]

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420 Dave Cooper, "Alberta government seeking to expand role of petroleum marketing commission" *The Edmonton Journal* (6 November 2013) (Factiva) [emphasis added].
421 6 December 2013, 2013-435, online: AUC <www.auc.ab.ca>.
422 *Ibid* at para 2.
423 *Ibid* at para 117.
424 *Ibid* at para 4.

Each of the five applications was evaluated on the three required criteria. The AUC indicated that a party applying for a capital tracker must demonstrate it meets the required criteria. It also offered interpretive guidance as to how parties could meet the capital tracker criteria.

ii. AUC Decision 2013-270: *2012 Performance-Based Regulation Second Compliance Filings*[425]

In this decision, the AUC offered guidance as to the calculation methodologies of regulated utilities using PBR. It endorsed forecast billing determinants for the purpose of future applications dealing with a true-up of PBR rates and their factors, except where a separate collection rider is used.[426] It also directed the utilities to explain their forecasting methodology clearly in future applications.[427]

iii. AUC Decision 2013-417: *Utility Asset Disposition*[428]

In this decision, the AUC commented on the application of *ATCO Gas and Pipelines Ltd v Alberta (Energy and Utilities Board)*, referred to as *Stores Block*.[429] *Stores Block* dealt with asset acquisition and disposition under the traditional rate base or rate-of-return utility rate-setting model. In it, the Court held that the Energy and Utilities Board (predecessor of the AUC) did not have jurisdiction to allocate to ratepayers any portion of the sale proceeds arising from the sale of a utility asset outside the ordinary course of business.[430]

The *Utility Asset Disposition* decision was issued pursuant to a notice issued by the AUC in April 2008, under which it gave utilities a chance to comment on the open issues created by *Stores Block*, with the goal of limiting a multiplicity of proceedings.

The AUC held that *Stores Block* and subsequent decisions had established numerous principles applicable to the acquisition and disposition of assets by a regulated utility.
The AUC considered whether the treatment of a gain or loss arising upon disposition of an asset within the ordinary course of business should be treated differently from a gain or loss arising upon disposition of an asset outside the ordinary course of business. The AUC found that the principles in *Stores Block* applied equally to both types of transaction.[431] *Stores Block* established that ratepayers do not hold any property interest in utility assets, which the AUC found would not be the case if customers stood to gain or lose from sales in the ordinary course of business.

The AUC also considered, where approval to dispose of an asset is conditional on partial reinvestment of the proceeds of the sale, how the reinvested proceeds should be treated. The AUC held that, where proceeds are required to be reinvested "in order to maintain a modern

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425 19 July 2013, 2013-270, online: AUC <www.aub.ab.ca>.
426 *Ibid* at para 21.
427 *Ibid* at para 22.
428 26 November 2013, 2013-417, online: AUC <www.auc.ab.ca> [*Utility Asset Disposition*].
429 2006 SCC 4, [2006] 1 SCR 140 [*Stores Block*].
430 *Utility Asset Disposition, supra* note 428 at para 34.
431 *Ibid* at paras 270-72.

operating system that achieves the optimal growth of the system," such proceeds should be treated as a capital investment entitled to earn a rate of return.[432]

With respect to stranded assets, the AUC held that utilities are entitled to recover reasonable costs associated with retirement, and affirmed that it is required to remove from the rate base assets not presently used and unlikely to be used in the future.[433] It also revised a previous decision in which it held that production abandonment costs could not be included in the revenue requirement and instead accrued to the account of the utility shareholder.[434] It held that production abandonment costs can be included in the revenue requirement where such costs were contemplated in prior depreciation provisions and normally expected at the end of the asset's expected service life.

Finally, the AUC considered the principle that a utility asset must be "used or required to be used" in the "operational sense." It held that assets used in the "operational sense" were those "that are presently used, reasonably used or likely to be used in the future to provide utility services."[435] It further directed all utilities to confirm which of its assets continued to be "used or required to be used," and to remove assets not meeting that requirement from its next revenue requirement filing.

4. ALBERTA SURFACE RIGHTS BOARD

i. *ARC Resources Ltd. v. Starling*[436]

Six lessors applied to the Alberta Surface Rights Board (SRB) for compensation reviews under section 27 of the *Surface Rights Act*[437] in respect of seven surface leases held by ARC Resources Ltd. (ARC). The leases related to four quarter sections of land.

ARC raised a preliminary jurisdictional issue. It argued that a written agreement between itself and one of the lessors settled the matter of compensation between them. The lessor argued that the agreement settled the matter only after its adoption and that the SRB had jurisdiction to consider a compensation award from before. The SRB held in favour of ARC. It concluded on an interpretation that the parties to the agreement intended to settle compensation for the period after. However, the SRB also held that its compensation review jurisdiction included agreements not concluded in accordance with the process set out in section 27 of the *SRA*.

On the main issue, the lessors argued that their land had increased in market value, and therefore should attract increased compensation. They adduced expert evidence. It focused on potential compensation in relation to hypothetical non-agricultural use. As grounds for their request for a reduction in compensation, ARC argued that the leased land was going to

432 *Ibid* at para 324, citing *Stores Block*, *supra* note 429 at para 77.
433 *Utility Asset Disposition*, *supra* note 428 at paras 302-303.
434 *Ibid* at para 317. The revised decision was *ATCO Gas 2011-2012 General Rate Application Phase I* (5 December 2011), 2011-450, online: AUC <www.auc.ab.ca/>.
435 *Utility Asset Disposition*, *ibid* at para 326.
436 12 November 2013, 2013 ABSRB 876, online: Alberta Surface Rights Board <surfacerights. alberta.ca/>.
437 RSA 2000, c S-24 [*SRA*].

be used for agricultural purposes based on a local pattern of dealings, and that compensation should flow based on agricultural use.

The SRB held that no pattern of dealings had been established by either party. It held that compensation was to be awarded on actual loss to the lessor from the operator's surface leases, not hypothetical future use. In order for a lessor to secure compensation based on a change in land use, it must put forward evidence that a market for such use existed, or alternatively that the operator was responsible for the lack of such a market.

Ultimately, the SRB rejected the lessors' position and reduced compensation on most of the leases. With respect to costs, the SRB disallowed most of the lessors' expert costs. It awarded 60 percent of the costs claimed by counsel for the lessor.

ii. *TAQA North Ltd. v. SL Developments Inc.*[438]

A surface lessor applied to the Board for a compensation review. The Town of Sylvan Lake had annexed the leased parcel in 2006. Subdivisions and planning approvals resulted in development of the boundaries of the parcel, but the majority of the land, which had previously been used for agriculture, was undeveloped and dormant.

The lessor claimed that, in the absence of the operator's well site, the leased parcel would have been developed with low density housing. The lessor sought compensation for loss of use, adverse effect, and costs associated with the construction of a temporary road and sanitation line, in total amounting to hundreds of thousands of dollars. The operator claimed that the lessor had not suffered any loss from its inability to develop the parcel, and that several of the alleged losses would have been reflected in the purchase price of the land. The operator proposed that annual compensation for the parcel remain unchanged at $2,600.00.

The Board raised the rate of compensation to $5,000.00 annually. It rejected the lessor's claim for loss of use based on a market value rate of return approach, and held that the surface lease had not resulted in the lands not being developed, and that such development was not imminent. It rejected the lessor's claim for adverse effects associated with the temporary road and sewer line, which it agreed had been factored into the purchase price of the land. It held that compensation of $5,000.00 reflected comparable payments in the area.

C. ONTARIO

1. BILL 69 – *PROMPT PAYMENT ACT, 2013*[439]

In May 2013, Bill 69, passed its second reading. Bill 69 has been proposed to supplement the *Construction Lien Act*,[440] and involves changes that could potentially have significant impacts on the construction industry.

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438 23 August 2013, 2013 ABSRB 580, online: Alberta Surface Rights Board <surfacerights.alberta.ca/>.
439 Bill 69, *An Act respecting payments made under contracts and subcontracts in the construction industry*, 2nd Sess, 40th Leg, Ontario, 2013 (second reading 16 May 2013) [Bill 69].
440 RSO 1990, c C.30 [*CLA*].

Bill 69 states that every contractor and subcontractor is entitled to receive mandatory progress payments, payable at least every 31 days. If the contract states that progress payments become payable at least every 31 days after the first day that services or materials are supplied, then the contract will govern.[441] If this is not the case, then the statutory scheme for progress payments will govern.[442] Not only could this change prevent parties from using their current structure of milestone progress payments, it may also impact project funding in a much broader sense. For example, if payments must be made every 31 days, this may impact the value of incomplete work, which in turn could impact the value of the project as security.

Additionally, the amendments would significantly modify the holdback regime in Ontario. Specifically, no holdbacks are permitted besides those retained under the *CLA*. Of particular note is section 4(2), which requires that all holdbacks must be paid back within one day after the payor is no longer required to retain the holdback under the *CLA*.[443] The major implication of this change is that it could interfere with contractual rights of set-off, and owners may look to other ways of off-setting this risk, such as surety bonds.

The statutory scheme states that for every monthly payment period, the contractor or subcontractor must prepare a process payment application that sets out the value of the supplies or materials that have been or will be supplied under the contract during the payment period.[444] The progress payment application must be based on reasonable estimates.[445] A payee may suspend work or terminate a contract if a progress payment is not made within the specified time frames,[446] which in the case of a contractor is 20 days after a progress payment is made, and in the case of a subcontractor, 30 days after a progress payment is made.[447] If the payor disagrees with the amount, the payor has 10 days to disagree in writing.[448] Construction contracts may have to be modified to deal with this requirement.

In addition, before entering into a contract, section 14 stipulates that an owner must provide the contractor with financial information "for the purpose of demonstrating the financial ability of the owner to make the payments provided for under the contract."[449] In addition, the contractor may at any time request the owner provide updated financial information and the owner must promptly provide such information.[450] Furthermore, "[w]hen a payer who is a contractor or subcontractor receives a payment … the payer shall promptly notify any subcontractor who supplies services or materials."[451] Stricter confidentiality clauses may have to be included in construction contracts to deal with these additional statutory requirements.

441 Bill 69, *supra* note 439, s 5(1).
442 *Ibid*, s 5(2).
443 *Ibid*, s 4(2).
444 *Ibid*, s 6(3).
445 *Ibid*, s 6(4).
446 *Ibid*, s 7.
447 *Ibid*, s 6.
448 *Ibid*, s 12.
449 *Ibid*, s 14(1).
450 *Ibid*, s 14(2).
451 *Ibid*, s 14(5).

D. NORTHWEST TERRITORIES

1. *NORTHWEST TERRITORIES DEVOLUTION ACT*

On 25 March 2014 the *Devolution Act*[452] received Royal Assent. Effective as of April 1, 2014, the *Devolution Act* transferred responsibility over the management of most public lands, water, and resources in the Northwest Territories from the federal government (through Aboriginal Affairs and Northern Development Canada) to the Government of the Northwest Territories.[453] The *Devolution Act* implements the provisions of the Northwest Territories Devolution Agreement, signed on 25 June 2013,[454] as well as amends certain provisions of the *Territorial Lands Act*,[455] *Northwest Territories Waters Act*,[456] and the *Mackenzie Valley Resource Management Act*.[457] The *Devolution Act* marks the completion of a gradual transfer of power from the federal government to the GNWT that began in 1967.[458]

With respect to natural resource development, the *Devolution Act* gives the Government of the Northwest Territories the power to, among other things: (1) make laws with respect to onshore exploration, development, conservation, and management of non-renewable natural resources within the Northwest Territories (including the issuance of relevant licences, leases, and mineral rights);[459] (2) make laws regulating the construction of onshore oil and gas pipelines; (3) regulate the inter-provincial export of non-renewable natural resources produced onshore;[460] and (4) control taxation on the production of natural resources.[461]

Additionally, the NEB will also maintain its current jurisdiction over certain oil and gas approvals in the Inuvialuit Settlement Region of the Northwest Territories and the Norman Wells Proven Area.[462]

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452 *Supra* note 1.

453 "Devolution of Lands and Resources in the Northwest Territories," online: GNWT <devolution.gov.nt.ca/>. Note that while the *Devolution Act* also transfers other province-like powers to the GNWT, a discussion of such powers is outside the scope of this article.

454 *Northwest Territories Lands and Resources Devolution Agreement* (25 June 2013), online: GNWT <devolution.gov.nt.ca/wp-content/uploads/2013/09/Final-Devolution-Agreement.pdf>.

455 RSC 1985, c T-7.

456 SC 1992, c 39, repealed by *Devolution Act*, *supra* note 1 and replaced by *Waters Act*, SNWT 2014, c 18.

457 SC 1998, c 25; "Backgrounder — Signing of the Northwest Territories Devolution Agreement," online: Aboriginal Affairs and Northern Development Canada <www.aadnc-aandc.gc.ca/eng/1372180456758/1372180489531>.

458 Government of Canada, News Release, "Harper Government Welcomes Granting of Royal Assent of Northwest Territories Devolution Act" (25 March 2014), online: <news.gc.ca/web/article-en.do?nid=829019>.

459 *Supra* note 1, s 19.

460 *Ibid*, s 19 (1)(e).

461 *Ibid*, s 19(3).

462 "NEB Regulatory Oversight in NWT Post-Devolution," online: NEB <https://www.neb-one.gc.ca/nrth/dvltn/index-eng.html>.

Important changes were also made to the *Mackenzie Valley Resource Management Act*, including provisions allowing for the establishment of a single "superboard" that would combine the four current regional land and water boards.[463] This has drawn criticism from a number of Aboriginal groups, who argue that such changes violate promises the federal government made to the Northwest Territories Aboriginal groups in various land claim agreements.[464]

463 "5 things to know about the proposed N.W.T. superboard," *CBC News* (4 December 2013), online: <www.cbc.ca/news/canada/north/5-things-to-know-about-the-proposed-n-w-t-superboard-1.2451084>.

464 Elizabeth McMillan, "Aboriginal groups oppose N.W.T. Devolution Act," *CBC News* (28 January 2014), online: <www.cbc.ca/news/canada/north/aboriginal-groups-oppose-n-w-t-devolution-act-1.2514077>.